niagara peninsula energy inc.
Your Local Utility

EXHIBIT 1
ADMINISTRATION

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Exhibit 1: Administrative Documents

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Tab 2 (of 10): Executive Summary

EXECUTIVE SUMMARY

1.2.1 Executive Summary

Niagara Peninsula Energy Inc. (NPEI) is a municipally owned electricity distribution company that provides electricity distribution and related services to approximately 56,000 customers in the City of Niagara Falls, the Town of Lincoln, the Township of West Lincoln and the Town of Pelham. The majority of residents live in the City of Niagara Falls.

NPEI is owned 74.5% by Niagara Falls Hydro Holding Corporation (NFHHC) and 25.5% by Peninsula West Power Inc. (PWP). NFHHC is owned 100% by the City of Niagara Falls and PWP is owned 59% by the Town of Lincoln, 24% by the Township of West Lincoln and 17% by the Town of Pelham.

NPEI is committed to ensuring that it is financially viable to make necessary investments to continue to provide a safe, reliable, quality service to its customers. NPEI's objective is to meet that commitment while maintaining fair and reasonable local distribution rates.

NPEI is dedicated to its local community and makes its decisions with its customers as its top priority. Below are the corporate mission and vision statements and the core values shared by all NPEI employees.

<u>Mission (this is who we are)</u> – **To deliver safe, efficient, and reliable electricity with excellent customer service and community value, provided by engaged employees.**

<u>Vision (this is who we want to be)</u> – **To be recognized as exceptional in delivering services and value, to our customers and communities.**

<u>Core Values</u> – **To conduct ourselves with commitment to the values of: Integrity; Fairness; Responsibility; and Respect.**

NPEI's mission, vision and core values align very closely to the performance outcomes identified by the OEB on its Scorecard that each LDC should strive to achieve – Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance.

Six focus areas of NPEI's business were identified as key strategy categories: Customers, Operational, Public Policy, People, Financial and Information Technology. For each key focus area, objectives, goals, measures of success, targets and actions were developed.

NPEI's strategic plan will be revisited periodically to ensure NPEI is on track to achieve its mission, vision, and values. Customer engagement, performance based outcomes, and cost/benefit analysis will be an integral part in decision making and allocation of NPEI's resources. NPEI's cost of service rate application, distribution system plan and customer engagement plan will guide the use of resources over the next rebasing period of five years.

NPEI's objectives and goals for each of the six key focus areas of its strategic plan are summarized below.

NPEI will understand and deliver on customer expectations for reliable, high quality, cost-effective service by enhancing customer satisfaction and customer engagement.

NPEI will productively manage assets and resources to meet current and future customer needs by expanding the transformation and distributions systems to meet the electrical needs of current and future customers. NPEI will effectively maintain and refurbish aging plant facilities and equipment, provide a high level of service quality, enhance system performance and reliability while ensuring 100% level of compliance with the Ontario Regulation 22/04 and promote public safety awareness.

NPEI will successfully deliver public policies, be environmentally responsible and respond to the needs of our communities. Smart Grid initiatives to improve reliability will be implemented to accommodate embedded generation. NPEI will be environmentally responsible, continuously engage in its communities and develop its corporate image.

NPEI will invest in a safe, healthy and engaging workplace that attracts, retains and develops employees who contribute their best. Health and safety awareness will be promoted for NPEI employees and its “Safety Culture” will be strengthened. NPEI will gain a mutual understanding of its employees’ job expectations; provide the equipment, resources and training to do the job well. Feedback and recognition of employee and team performance will be provided on a timely and ongoing basis. Employees will be provided with development opportunities, integrated with a corporate succession plan to sustain operations.

NPEI will deliver sustainable shareholder value and meet or exceed regulatory expectations. Long-term financial viability will be maintained and NPEI’s balanced scorecard will be met or exceeded. NPEI will maintain regulatory compliance and meet or exceed the Ontario Energy Board’s (OEB) scorecard expectations. Shareholder value will continuously be enhanced and dividend expectations will be met.

NPEI will continually improve with a focus on innovation and technology in all areas of the business and provide integrated solutions to meet customer and business needs.

NPEI has been a trusted partner in the City of Niagara Falls, the Town of Lincoln, the Township of West Lincoln and the Town of Pelham since 1915, committed to the safe, reliable delivery of electricity.

NPEI is one of the original founders of LDC members that make up the GridSmartCity Cooperative (GCS), a consortium created to improve service to electricity customers by increasing the efficiencies of scale and scope, while maintaining independent ownership directly in the towns and cities in which the respective LDC’s operate. GSC members collectively;

- Represents a service area of 3,865 square kilometers with a total of 16,160 kilometers of power lines;
- One of top four in Ontario’s electricity sector by size and performance # of Customers;

GSC is a formalized entity with objectives that focuses on achieving cost benefits for its customers by pursuing economies of scale, efficiencies and effectiveness through collaboration and collective purchasing power.

GSC has continued to develop and shape a network of opportunity that lend itself to creating the building blocks to secure a strong and lasting foundation, strengthened by common goals that form the basis to provide a compelling alternative to consolidation.

Review of COVID-19 Impacts

NPEI was scheduled to file its 2021 COS Rate Application by April 30, 2020, for rates effective January 1, 2021.

NPEI closed its doors to the public on March 12, 2020 but continued to deliver distribution service through a combination of remote working, modified work in the office and field.

On April 17, 2020, NPEI filed a letter with the Board requesting an extension to the date for filing the 2021 COS Rate Application. At that time, little was known about COVID-19 and given the uncertainty, NPEI indicated that it would update the Board on or before August 31, 2020. In its letter, NPEI indicated that the extension would allow NPEI to gain a better understanding of what impacts, if any, the COVID-19 pandemic would have on its 2021 COS Rate Application. On April 20, 2020, the OEB issued a letter granting NPEI’s request.

In addition, in April the Board provided LDCs with the opportunity to defer the implementation of the May 1, 2020 rate orders. As NPEI had previously received the Board's decision to be implemented rates effective May 1, 2020, it required the Board to vary its prior order. NPEI received from the OEB a Vary Order to postpone the implementation of its May 1st rate increase to November 1, 2020 on April 28, 2020.

NPEI has reviewed the elements of its 2021 COS Rate Application in the context of the COVID-19 pandemic. The results of NPEI's review, based on information available as at July 31, 2020, are summarized below.

Approach to Managing During COVID-19

In order to address the financing needs of NPEI, a detailed cash flow model was developed in March 2020 as a result of the COVID-19 pandemic. The model is updated daily for all banking transactions, billing journals, outstanding accounts receivable and all cash outflows including payroll and related liabilities, flow through charges (i.e. monthly power bill), loan payments, and accounts payable related to capital spending, inventory purchases and operations and maintenance expenses. NPEI reviewed its' capital budget plan and OM&A for 2020 and 2021 in April and has continued to monitor it throughout.

Capital Expenditures

The start of the 2020 capital project program was delayed due to a combination training of new hires in engineering, scope changes in customer driven work and process changes due to COVID-19.

During the week of April 13th, a review of the planned capital spending for 2020 was performed due to the uncertainty with potential implications of the COVID-19 pandemic. All planned capital expenditures were reviewed to determine which were candidates for deferral. Work that was driven by customer system access needs such as energization of new subdivisions, service upgrades, system expansions and pole relocation work required to facilitate municipal projects were maintained.

Long lead time items such as the ordering of a new radial boom derrick truck were maintained as well as protection and control relay renewal projects at NPEI's Kalar TS required to maintain system reliability.

As a result of the 2020 capital budget review, the decision was made to defer the replacement of a metering department van to 2021. In addition, some of the planned smart grid initiatives and the continued roll out of the WiMAX radio network were also deferred to 2021. A planned new system feeder tie point at Greenlane and Ontario St. was also deferred to be completed within the next five years as the work was a proposed system improvement under system service and not immediately required by our customers.

Due to the uncertainty of what the COVID-19 pandemic may mean for staff availability due to illness, the decision was made to focus much of the initial system renewal work on individual pole replacements as opposed to the planned area rebuilds. This would allow NPEI to continue with needed system renewal work, while also keeping the scope of the work smaller in the event that manpower shortages arose. Stopping work on these smaller projects would be would be much less impactful on our customers in the event that work needed to stop than a larger area re-build of an older overhead distribution subdivision. One of the initial safety protocols implemented by NPEI was to limit one crew member per vehicle in order to ensure proper physical distancing. As a result of this safety measure, equipment utilization costs for capital projects increased but NPEI has been able to continue to make progress on its capital program.

As the pandemic progressed and we better understood the impact, or lack thereof, on our workforce, NPEI shifted the focus back to the planned area rebuilds in June and July. As a result of this approach, some system renewal work planned for 2020 will carry over into 2021.

In managing its capital expenditure program, NPEI is balancing several objectives including: minimizing potential cost implications for our customers; ensuring sufficient cash flow; and maintaining relatively consistent levels of capital expenditures. As such 2020 capital work projects which carry forward into the 2021 test year due to delays from COVID-19, will displace comparable work previously planned for 2021. For example, a system renewal project that was planned for and started in 2020 which carries into 2021 due to a delayed start, will push back the start of a 2021 test year system renewal project or reduce the number of individual pole replacements completed in 2021 as the resources are utilized to complete the remainder of the 2020 project. 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.

OM&A

A similar review was performed with respect to NPEI's OM&A expenses. From the beginning of the state of emergency enacted by the Provincial Government of Ontario in March 2020, NPEI maintained all of its hourly employees to be at work every day and fifty percent of the management employees rotated from either working in the office or remotely working from home. Work plans shifted. In order to keep operations crews working in March, April and May, 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 also had an issue with an overhead load break switch failing during switching operations earlier in the year which resulted in a short outage. As a corrective action, NPEI had a crew take a closer look at our inventory of overhead load break switches in the system and performed additional maintenance and alignment on them. Much of this work was done in April. The impact of increased maintenance work in the first four months increased the labour expensed to OM&A. As part of new safety procedures related to COVID-19, NPEI only allows one employee per vehicle in order to maintain physical distancing. The fuel expenses and the truck utilization or fleet burden have increased due to higher usage of the vehicles.

NPEI performed a review of all of the OM&A expenses budgeted for in 2020 and identified controllable expenses that could be delayed to the fall of 2020 pending the state of the pandemic. Approximately, $600,000 of OM&A expenses were identified to not be incurred in 2020 as a result of the pandemic. NPEI was in the process of hiring the Regulatory Accounting Manager at the onset of the state of emergency. Due to physical distancing and NPEI being closed to the public, the interviews could not be held. NPEI also budgeted to replace an Engineering Technician in the first quarter of 2020. The recruitment and hiring for these two positions has been deferred to the fourth quarter of 2020. NPEI also has an employee who went on EI due to health concerns related to COVID-19. This employee will return to work when it is safe to do so. All consulting work, third party engineering assessments, training, travel and the transformer case study expenses have been deferred to 2021. Due to the extension of the disconnection ban to July 31st, 2020, NPEI's third party collection expenses will be less than the 2020 budgeted amount. The estimated increase in bad debts expenses related to the pandemic have been accounted for in the new deferral and variance account 1509 which was established by the OEB on March 25, 2020. The deferment of these expenses to 2021 will not impact the Test Year OM&A requested in the 2021 Cost of Service rate application at this time.

As part of the cash flow review, NPEI received approval from its Board of Directors in May to obtain an additional emergency line of credit facility. This new facility is temporary and will expire at the end of 2020. There is a standby fee associated with this temporary facility which will be recorded in the new deferral and variance account 1509. As at the end of July 2020, NPEI has a positive cash flow and has not drawn upon any credit facility.

Customer Counts

Since the Government of Ontario declared a provincial state of emergency on March 17, 2020, NPEI has experienced a slight decrease in Residential customer counts as compared to forecast. The commercial customer counts have remained unchanged from December 2019. NPEI has analyzed and reviewed the number of customers billed, first bills issued, final bills issued, number of new connections and the number of requests received from developers for new subdivision expansions.

Since the emergency was declared, NPEI has continued to connect new customers and receive requests from developers to commence new subdivision projects.
Based on this analysis and review, NPEI believes that the originally prepared 2021 test year customer count is still appropriate at this time.

Demand, Consumption and Cost of Power

NPEI has closely monitored the daily consumption and demand, where applicable, by customer class, since the Government of Ontario declared a provincial state of emergency on March 17, 2020. The only significant decline noted to date is the demand for the GS>50 kW class. NPEI views this decline as temporary at this time, and anticipates a return to more typical levels in the 2021 test year as further COVID-19 related restrictions are lifted.

Based on this review, NPEI believes that the originally prepared 2021 test year consumption and demand forecast, and the resulting 2021 Test Year cost of power incorporated into the revenue requirement calculation, are still appropriate at this time.

COVID-19 Deferral Account

NPEI has recorded incremental costs relating to the COVID-19 pandemic, and loss of revenue relating to loss of load in Account 1509 Impacts Arising from the COVID-19 emergency. The OEB has initiated a stakeholder consultation relating to Account 1509, which is still ongoing. NPEI proposes to request disposition of its Account 1509 balances at a future date, in accordance with the results of the consultation.

COVID-19 Deferral Account - Sub-Account Foregone Revenues from Postponing Rate Implementation.

NPEI opted to defer the implementation of its OEB-approved rates for May 1, 2020 until November 1, 2020.

On August 6, 2020, the OEB issued an Accounting Order establishing a new sub-account called Impacts Arising from the COVID-19 Emergency, Sub-account Foregone Revenues from Postponing Rate Implementation.

NPEI proposes to recover lost revenues relating to the deferral of its May 1, 2020 rates in accordance with the guidance provided in the accounting guidance letter. NPEI will submit, a stand-alone rate application under EB-2020-0054 on or before September 15, 2020 which will include the OEB's Foregone Revenue from Postponing Rate Implementation Model. Bill impacts for this 2021 Cost of Service Rate application compare the May 1, 2020 tariff of rates and charges being implemented on November 1, 2020. The rate rider for postponement of the May 1, 2020 rates has not been included in the bill impact calculations as the model for Foregone Revenue from Postponing Rate implementation was made available to LDC's on August 6th, 2020. NPEI will update the bill impacts of the 2021 Cost of Service rate application during the interrogatory process.

Conclusion

In conclusion, after detailed analyses and review based on the best information available at the time, NPEI is filing its 2021 COS Rate Application as originally prepared.
NPEI is requesting approval for its 2021 rates to be effective January 1, 2021.

BUSINESS PLAN

1.2.2 Business Plan

NPEI's business plan is comprised of a strategic plan as well as annual operating and capital budgets. In 2015, NPEI engaged a third party consultant to facilitate the preparation of NPEI's strategic plan. The third party consultant met with NPEI's Board of Directors and senior management staff. NPEI's mission, vision and values were updated. NPEI developed a S.W.O.T. analysis which incorporated its strengths, weaknesses, opportunities and threats. NPEI developed six focus areas: customers; operational; financial; people; public policy and information technology. NPEI's senior management developed objectives, goals, measures of success and target dates for each focus area. NPEI's 2016 strategic plan is included in Appendix 1-8. In 2020, NPEI updated its strategic plan and received approval from its Board of Directors in April 2020. Upon completion of the 2021 Cost of Service rate application process, NPEI will update its strategic plan.

Each year NPEI prepares a detailed operating and capital budget. The operating and capital budgets are prepared in accordance with NPEI's strategic plan. NPEI has included its operating and capital budgets for 2020 in Appendix 1-2. Appendices 1-3 to 1-7 include the operating and capital budgets for the years 2015 to 2019.

NPEI's operating and capital budgets both reflect the organization's continued efforts in maintaining its customer satisfaction, reliability and safety statistics and financial performance targets. NPEI continues to provide safe and reliable electricity to its customers. The introduction of a defined process to reach out directly to customers to better understand their needs priorities and preferences aligns with NPEI's business model and core values (Customer Focus, Financial Responsibility, Safety, Communication, Integrity and Fairness).

The budgets reflect on NPEI's prudent and measured approach over the past many years in executing its business model and operational activities. The budgets and strategic plan also identify the evolving and transformational changes impacting the electricity sector and outlines how NPEI seeks to maintain a reasonable pace in implementing new programs and technology against controlling costs, managing risk, adapting to change and meeting customer's expectations. The operating and capital budgets supports the need to prepare for the changing environment and new technologies and has strong support from customers (See Section 1.6 Customer Engagement) who agree with what is currently in the plan or an approach that accelerates the planned investments.

The total spend changes little between the years 2019 and 2021. Controllable costs are influenced by many factors (both internal and external) such as labour and benefit costs, insurance costs, software maintenance costs etc. While NPEI will continue to look for efficiencies wherever possible, there are limited opportunities to reduce costs. NPEI has budgeted for an increase of 2.4% in total OM&A expenses in the 2020 Bridge Year over 2019 and an increase of 3.9% in total OM&A in the Test Year 2021 over the 2020 Bridge year for controllable expenses. NPEI has utilized a "total spend" approach for many years, moving dollars spent between capital and operating as required, always cognizant that the same pool of limited resources is used to accomplish the needed programs and the same customer is paying for both. The total spend also includes new capital investments of $84.8M over the next five years, from 2021 to 2025, focused primarily on system access projects related to the new hospital and the 2021 Canada Summer Games as well as additional capacity at NPEI's own transformer station, and system renewal projects for pole replacements, transformer replacements and underground subdivision rehabilitations.

NPEI's strategic plan provides a high-level overview of the initiatives and programs that account for NPEI's five year planning cycle. NPEI has aligned its activities and focus with the results of its customer engagement feedback.

A prudent and sound financial plan, that includes a modest increase in staffing levels, specific to regulatory and customer engagement. NPEI's financial plan assumptions are based on: 2.0% inflationary increase; regulatory assets/liabilities not estimated beyond known items; and the discontinuance of NPEI-led Conservation and Demand Management (CDM) programs in 2019.

NPEI has taken its customer's needs, priorities and preferences into strong consideration in developing its five-year distribution system plan. The organization has a solid understanding of its current and future challenges relative to technology, resources, growth and a changing energy sector/environment. NPEI will continue to be a financially viable business, that continually balances cost against customer value.

NPEI'S TOTAL SPEND APPROACH

1.2.3 Total Spend Approach

NPEI reviews its budgets using different methodologies to ensure its proposed budgets are reasonable before asking its Board of Directors for approval. Methodologies employed include the Bottom Up Approach, the Top Down Approach and the Total Spend Envelope.

Bottom Up Approach

The bottom up approach is performed at the detail level, employing the expertise of each responsible Director or Vice President to create departmental budgets by expense type. The labour budget is prepared in detail by employee using current pay rates, estimated performance increases in pay rates and estimated overhead burden rates. All new FTE positions and replacement of FTE's retiring or leaving the corporation are approved by NPEI's President/CEO. The following

- Estimated OM&A expenses for all department budgets are built using the previous two years of actual often using actual invoices by Vendor, current year forecast and current year budget as the base;

- Significant variances in spending from prior years are explained in the budget report;

- The Finance department prepares a total labour budget by employee by department using projected wage and benefit costs. Overtime and account distribution are projected considering previous year's actual

- The labour required for the capital budget is reconciled to the total labour budget where the difference become OM&A labour. This only applies to the direct labour positions that are capitalized. NPEI does not capitalize any management labour costs.

- Depreciation expenses are calculated using the forecast current year's additions by general ledger account divided by the useful lives and application of the half year rule for pooled assets. Budget depreciation expense incorporates the previous year's forecasted additions plus the budgeted capital additions divided by the useful lives and application of the half year rule for pooled assets. Depreciation expense related to identifiable assets (Account 1915 to 1980) are budgeted using the worth-it stand alone software program.

- Income taxes are budgeted using a 26.5% tax estimate. Future income taxes are not accounted for the annual budget.

- Net movement in regulatory accounts are budgeted for all regulatory assets and liabilities except for RSVA (Retail Settle Variance Accounts) accounts. Due to many challenges related to these accounts, NPEI's Sale of Energy equals its Cost of Power in the annual budget.

Top Down Approach

The top down approach can be performed in aggregate or at the individual expense level. NPEI employs both strategies. This method tests the proposed expenses and capital expenditures against expected inflation. Outliers are identified and explained in the annual budget report.

Total Spend Approach

NPEI employs the Total Spend Approach in all of its budgeting and actual spend monitoring throughout the year. NPEI can reasonably estimate what its total envelope will be in any given year. Budgets are then developed using the Total Spend that is approved in rates, inclusive of both the capital and operating budgets. If capital requirements are higher or lower in any given year, the offset will increase or decrease the operating budgets where possible. 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.

Table 1.2.3-1 below illustrates the total spend for the 2019 Actual, 2020 Bridge Year and 2021 Test Year.

1 **Table 1.2.3-1 Total Spend 2019 – 2021**

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	Actual 2019	Bridge Year 2020	Test Year 2021
Gross Capital Cost			
Opening Balance	320,005,612	336,175,261	353,457,606
Capital Additions	16,947,193	17,564,198	17,942,655
Capital Disposals	(777,544)	(281,853)	(565,057)
End Gross Capital Cost	336,175,261	353,457,606	370,835,204
Capital Contributions			
Opening Balance	(37,095,719)	(42,558,399)	(46,412,572)
Additions	(5,462,680)	(3,854,173)	(2,583,228)
End CC	(42,558,399)	(46,412,572)	(48,995,800)
Net Capital Cost	293,616,863	307,045,034	321,839,405
Average Gross FA			314,442,219
Accumulated Depreciation			
Opening Balance	(151,478,242)	(158,593,945)	(166,536,274)
Depreciation	(7,818,837)	(8,224,182)	(8,442,650)
Capital Disposals	703,134	281,853	565,057
End Accumulated Deprec	(158,593,945)	(166,536,274)	(174,413,867)
Amortization CC			
Opening Balance	9,920,039	10,922,804	12,049,613
Amortization CC	1,002,764	1,126,809	1,211,588
End CC	10,922,804	12,049,613	13,261,201
Net Accumulated Depreciation	(147,671,141)	(154,486,661)	(161,152,666)
Average Accum Depreciation			(157,819,664)
Average Fixed Assets in Rate Base			**156,622,556**
OM&A per 2-JA			
Operations	4,985,677	4,848,724	4,798,729
Maintenance	2,678,573	2,567,275	2,577,832
Billing&Collecting	5,966,076	6,406,032	6,792,581
Community Relations	133,276	129,200	102,200
Administrative & General	5,395,203	5,672,162	6,112,668
Total OM&A	19,158,806	19,623,392	20,384,010
Year over Year OM&A $ change		464,586	760,618
Total Spend	**30,643,319**	**33,333,416**	**35,743,437**
Year over Year Total Spend $ change		2,690,097	2,410,021
Mainly due to decrease in Capital Contributions rec'd		8.78%	7.23%

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CUSTOMER SUMMARY

1.2.4 Customer Summary

NPEI has applied to the Ontario Energy Board for a change in the distribution rates that it charges its customers. The distribution rates are based on the amount of capital investments made by NPEI as well as the cost to operate and maintain the capital investments, along with a percentage for a return on equity. The impact to customers is:

Table 1.2.4-1 Total Bill Impacts

RPP

	kWh	kW	Total Bill Change $	Total Bill Change %
Residential	750		1.53	1.26%
GS < 50 kW	2,000		3.16	1.05%
GS > 50 kW	65,000	180	5.75	0.05%
Sentinel	44	0.12	1.19	5.30%
Streetlight	50	0.13	0.11	1.01%
Unmetered Scattered Load	250		0.04	0.08%

non-RPP

	kWh	kW	Total Bill Change $	Total Bill Change %
Residential	750		1.59	1.45%
GS < 50 kW	2,000		3.33	1.22%
GS > 50 kW	65,000	180	13.06	0.12%
Sentinel	44	0.12	1.19	5.48%
Streetlight	50	0.13	0.12	1.17%
Unmetered Scattered Load	250		0.06	0.13%

NPEI has a service area of 827 square kilometers that provides electricity distribution to approximately 56,000 residential and commercial customers. NPEI is incorporated under the Ontario Business Corporations Act and is 100% municipally owned by the City of Niagara Falls, the Town of Lincoln, the Township of West Lincoln and the Town of Pelham.

NPEI currently has the following customer rate classes: Residential, General Service < 50 kW, General Service > 50 kW, Streetlighting, Sentinel Lighting, and Unmetered Scattered Load. These rate classes were approved in the last Cost of Service rate application in 2015. NPEI is not proposing any new rate classes or is proposing any changes to the existing rate classes in this 2021 Cost of Service rate application.

Customer counts are presented in Table 1.2.4-1 below:

Table 1.2.4-1 Customer Counts

	Approved				Proposed		
	2015 Cost	Actual	5 year	5 year	2021 Cost	2 year	2 year
	of Service	Dec-19	change	% change	of Service	Change	% change
Residential	47,067	50,792	3,725	7.91%	51,935	1,143	2.25%
GS< 50 kW	4,385	4,475	90	2.05%	4,541	66	1.48%
GS > 50 kW	862	800	(62)	-7.17%	810	10	1.23%
Unmetered Scattered Load	422	335	(87)	-20.70%	325	(9)	-2.75%
Sentinel (connections)	303	296	(7)	-2.37%	283	(12)	-4.18%
Streetlight (connections)	12,989	13,360	371	2.86%	13,634	274	2.05%
	66,028	70,057	4,029	6.10%	71,529	1,472	2.10%

Exhibit 1: Administrative Documents

Tab 3 (of 10): Administration

STATEMENT OF COMPLETENESS AND ACCURACY

1.3.1 Statement of Completeness and Accuracy

Niagara Peninsula Energy Inc. certifies this Cost of Service rate application is complete and accurate in accordance with the Filing Requirements for Electricity Distribution Rate Applications-2018 Edition for 2019 Rate Applications, last revised on July 12, 2018 and the Addendum to Filing Requirements for Electricity Distribution Rate Applications -2020 Rate Applications issued July 15, 2019.

APPLICATION CONTACT INFORMATION

1.3.2 Application Contact Information

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LEGAL APPLICATION

1.3.3 Legal Application

IN THE MATTER OF the Ontario Energy Board Act, 1998, being Schedule B to the Energy Competition Act, 1998, S.O. 1998, c.15;

AND IN THE MATTER OF an application by Niagara Peninsula Energy Inc. to the Ontario Energy Board for an Order or Orders pursuant to section 78 of the Ontario Energy Board Act, 1998 for 2021 distribution rates and related matters.

APPLICATION:

1. The Applicant is Niagara Peninsula Energy Inc. ("NPEI") is a corporation incorporated pursuant to the Ontario *Business Corporations Act* with its head office in the City of Niagara Falls. NPEI is a licensed electricity distributor operating pursuant to license ED-2007-0749. NPEI carries on the business of distributing electricity to approximately 56,000 customers within the City of Niagara Falls, the Town of Lincoln, the Township of West Lincoln and the Town of Pelham pursuant to a distribution license (ED-2007-0749) issued by the Ontario Energy Board (the "Board") and charges Board authorized rates (EB-2019-0054) for the distribution service it provides.

2. The Application has been prepared pursuant to the OEB's *Renewed Regulatory Framework for Electricity Distributors* as detailed in the Report to the Board October 18, 2013 (RRFE)

3. The Applicant hereby applies to the Ontario Energy Board (the "OEB") for an order or orders made pursuant to Section 78 of the *Ontario Energy Board Act, 1998 (the "OEB Act")*, as amended, approving just and reasonable rates for the distribution of electricity based on a 2021 Test Year, effective January 1, 2021.

4. The Applicant followed Chapter 2 of the OEB's Filing Requirements for Transmission and Distribution Applications dated July 12, 2018 and the Addendum to Filing Requirements for Electricity Rate Applications-2020 Rate Applications dated July 15, 2019.

5. The Applicant has prepared a Consolidated Distribution System Plan (DSP) in accordance with the Chapter 5 of the OEB's Filing Requirements for Electricity Transmission and Distribution Applications, dated July 12, 2018.

6. The 2021 distribution rates proposed by the Applicant will result in overall bill impacts for residential, GS < 50kW, GS>50kW, Unmetered Scattered Load (USL), sentinel and street light customers as detailed in Table 1-1 below. A full list of the bill impacts applicable to all customer classes is found at 8.5.2 and. The proposed schedule of rates and charges in this Application are identified in Appendix 8-5.

Table of Bill Impacts

Rate Class	kWh	kW	Distribution (Fixed and Volumetric) Current 2020	Proposed 2021	$ Change	% Impact	Total Bill Current 2020	Proposed 2021	$ Change	% Impact
Residential	750	0	33.67	36.15	2.48	7.37%	121.11	122.64	1.53	1.26%
GS< 50 kW	2,000	0	69.35	74.51	5.16	7.44%	302.71	305.88	3.17	1.05%
GS > 50 kW-(non-RPP)	65,000	180	751.2	817.81	66.61	8.87%	10,701.42	10,714.48	13.06	0.12%
Sentinel -(non-RPP)	44	0.12	20.73	22.26	1.53	7.38%	21.71	22.90	1.19	5.48%
Streetlight-(non-RPP)	50	0.13	1.92	1.11	-0.81	-42.19%	9.80	9.92	0.12	1.22%
Unmetered Scattered Load	250	0	24.33	24.81	0.48	1.97%	50.68	50.72	0.04	0.08%

7. This Application is supported by written evidence. The written evidence will be pre-filed and may be amended from time to time, prior to the Board's final decision on this Application.

8. The Applicant certifies that the information provided in this application is accurate at the time of this filing.

9. The Applicant acknowledges that the Board will publish an update to the Rate of Return and Short Term Debt Rate and that these matters will affect the Revenue Requirement that NPEI has requested in this Application.

10. The Applicant requests that a copy of all documents filed with the Board in this proceeding be served on the Applicant.

11. The Applicant requests that the OEB make its Rate Order effective January 1, 2021 in accordance with the Filing Requirements. NPEI is requesting approval to align its rate year with its fiscal year in the 2021 Cost of Service Rate Application.

12. The Applicant applies for an Order or Orders approving the proposed distribution rates and other charges set out in the Proposed Rate Tariff in Appendix 8-5 as just and reasonable rates and charges pursuant to Section 78 of the OEB Act, to be effective January 1, 2021, or as soon as possible thereafter; and

13. The Applicant requests that this Application be disposed of by way of written hearing.

DATED at: Niagara Falls, Ontario. This 31st day of August 2020.

All of which is respectfully submitted,

Original Signed By

Certification

I, Suzanne Wilson, Senior Vice-President of Finance of Niagara Peninsula Energy Inc., certify that the evidence file is accurate, consistent, and complete to the best of my knowledge.

Suzanne Wilson

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

IDENTIFICATION OF LEGAL REPRESENTATION

1.3.4 Identification of Legal Representation

Niagara Peninsula Energy Inc. will have legal representation throughout the entire rate application process.

Aird & Berlis LLP
Scott Stoll
Brookfield Place,
181 Bay Street, Suite 1800
Toronto, Ontario
M5J 2T9
416-865-4703
sstoll@airdberlis.com

INTERNET ADDRESS AND SOCIAL MEDIA

1.3.5 Internet Address and Social Media

Niagara Peninsula's website address is **www.npei.ca**.

Niagara Peninsula Energy has a Facebook account under the name Niagara Peninsula Energy. As of August 31, 2019, NPEI has over 2,600 Facebook followers.

Niagara Peninsula Energy has a Twitter account @NPEIHydro. As of August 31, 2019, NPEI has just over 2,500 Twitter followers.

STATEMENT OF WHO WILL BE AFFECTED BY APPLICATION

1.3.6 Statement of who will be affected by the application

All of Niagara Peninsula Energy's customers may be affected by this application.

NOTICE OF HEARING PUBLICATION

1.3.7 Notice of hearing publication

NPEI will publish the Notice of Application in the local paper as follows:

- Publication of the English version of the Notice of Application for an Electricity Distribution Rate Change in the Niagara Falls Review, the West Niagara News and the Lincoln Grimsby News within fourteen days of receiving the Board's Letter of Direction and Notice of Application. The Niagara Falls Review is the newspaper having the highest paid circulation in the service area, according to the best information available.

- Make a copy of the application and evidence available for public review at Niagara Peninsula Energy's head office.

Will make a copy of the application and evidence, and any amendments thereto, available to any intervenor requesting the material.

BILL IMPACTS

1.3.8 Bill Impacts

The OEB Excel file 2021_Tariff_Schedule_and_Bill_Impact_Model_20200514 is included in Appendix 1-34 of this Exhibit. The model includes NPEI's current tariff of rates and charges effective May 1, 2020. NPEI received its IRM decision and Order to change rates effective May 1, 2020 on December 12, 2019. On April 16, 2020, the Board issued its letter Re: Approach to Incentive Rate-Setting Decisions for May 1, 2020 Rates, which provided the option for distributors to postpone the changes in rates to November 1, 2020, due to the uncertainty regarding the severity and duration of the COVID-19 pandemic. NPEI opted to defer the implementation of its May 1, 2020 rates to November 1, 2020. NPEI will file a stand-alone rate application on or before September 15, 2020 under EB-2020-0054 requesting a November 1, 2020 implementation date.

The bill impacts are calculated by comparing existing rates approved in NPEI's 2020 IRM (EB-2019-0054) to proposed distribution rates for NPEI's 2021 test year including all applicable rate riders and proposed 2021 Retail Transmission Service Rates.

Table 1.3.8-1 below details the Total Bill Impact for typical NPEI customers.

Table 1.3.8-1 2021 COS – Total Bill Impacts for Typical NPEI Customers

Customer Class	Volume kWh	Volume kW	2020 Distribution charges	Proposed Distribution Charge	Distribution Charge $ Change	Distribution Charge % Change	2020 Total Bill	2021 Proposed Total Bill	Total Bill $ Change	Total Bill % Change
Residential	750		33.67	36.15	2.48	7.37%	121.11	122.64	1.53	1.26%
GS < 50 kW	2,000		69.35	74.51	5.16	7.44%	302.71	305.88	3.17	1.05%
GS > 50 kW	65,000	180	751.2	817.81	66.61	8.87%	10701.42	10714.48	13.06	0.12%
Sentinel	44	0.12	20.73	22.26	1.53	7.38%	21.71	22.9	1.19	5.48%
Streetlight	50	0.13	1.92	1.11	-0.81	-42.19%	9.8	9.92	0.12	1.22%
Unmetered Scattered Load	250		24.33	24.81	0.48	1.97%	50.68	50.72	0.04	0.08%

Table 1.3.8-2 below details the bill impact related only to the distribution portion of the bill for typical NPEI customers.

Table 1.3.8-2 2021 COS – Distribution Portion – Bill Impacts (excluding rate riders)

Customer Class	Volume kWh	Volume kW	2020 Distribution charges	2021 Proposed Distribution Charge	Distribution Charge $ Change	Distribution Charge % Change
Residential	750		33.67	36.15	2.48	7.37%
GS < 50 kW	2,000		69.35	74.51	5.16	7.44%
GS > 50 kW	65,000	180	751.2	817.81	66.61	8.87%
Sentinel	44	0.12	20.73	22.26	1.53	7.38%
Streetlight	50	0.13	1.92	1.11	-0.81	-42.19%
Unmetered Scattered Load	250		24.33	24.81	0.48	1.97%

There are no rate classes where the distribution portion of the bill exceeds an increase of 10%, and as a result there is no need for rate mitigation.

All bill impacts for all classes RPP and non-RPP are shown in detail in Exhibit 8.

STATEMENT OF REQUESTED HEARING FORM

1.3.9 Statement of requested hearing form

This Application is supported by written evidence. The written evidence will be pre-filed and may be amended from time to time, prior to the Board's final decision on the Application.

NPEI requests that, pursuant to Section 34.01 of the Board's *Rules of Practice and Procedure*, this proceeding be conducted by way of written hearing.

EFFECTIVE DATE REQUESTED

1.3.10 Effective date requested

Niagara Peninsula Energy Inc.'s current Tariff of Rates and Charges as per the Decision and Rate Order EB-2019-0054, dated December 12, 2019 has an effective date of May 1, 2020 is included in Appendix 1-11.

On November 27, 2018, the Ontario Energy Board ("OEB") issued a letter identifying those electricity distributors that are scheduled to file a cost of service application for 2020 rates. Niagara Peninsula Energy Inc.'s ("NPEI's") rates were last set on a cost of service basis for rates effective June 1, 2015 (EB-2014-0096). NPEI is currently included on the OEB's 2020 rebasing list for rates effective May 1, 2020.

In its letter, the OEB advised that distributors whose current rate year commences on May 1 that plan on requesting a change to a January 1 rate year should notify the OEB of this intent no later than March 1, 2019. The letter also indicates that any distributor that has been included on the 2020 rebasing list but wishes to defer rebasing beyond the 2020 rate year must advise the OEB by March 1, 2019.

On February 13, 2019 NPEI requested approval to defer its cost of service rate application for 8 months, such that NPEI would file a cost of service rate application for rates effective January 1, 2021. The reason for this request is to align NPEI's rate year with its fiscal year and Reporting and Record Keeping Requirements ("RRR") reporting year. NPEI will be able to manage its resources and financial needs within the revenue under the 4th Generation Price Cap Adjustment and maintain an adequate ROE and customer service.

On May 13, 2019, NPEI received the following response from the OEB with respect to deferring its Cost of Service Rate Application:

> "This letter is in response to your letter expressing an interest to defer Niagara Peninsula Energy Inc.'s (NPEI) rebasing of its rates beyond the 2020 rate year.
>
> The Ontario Energy Board (OEB) has reviewed your letter, as well as NPEI's financial and non-financial scorecard performance from 2013 to 2017. Based on this review, the OEB has concluded that it will not require NPEI's 2020 rates to be set on a cost of service basis. The OEB will place NPEI on the list of distributors whose rates will be scheduled for rebasing for the 2021 rate year.
>
> If NPEI intends to seek a rate adjustment for 2020 rates, the OEB expects NPEI to adhere to the process for Price Cap Incentive Rate-setting applications for the 2020 rate year."

NPEI submitted an IRM application (EB-2019-0054) on August 9th, 2019 for rates effective May 1, 2020.

NPEI is requesting in this Cost of Service Rate Application that its Tariffs of Rates and Charges be effective January 1, 2021.

On April 16, 2020, the OEB issued decisions and rate orders relating to the IRM applications filed by 31 distributors for new rates effective May 1, 2020. On the same day, the OEB issued a letter explaining the approach in light of the uncertainty regarding the severity and duration of the COVID-19 emergency, distributors had been given the option to postpone implementation of their May 1, 2020 rates until November 1, 2020. The OEB confirmed that the "implementation options and the guidance provided in this letter also apply to distributors who were issued an OEB Decision and Rate Order on December 12, 2019 for rates effective May 1, 2020 (EB-2019-0030 and EB-2019-0054)".

NPEI filed a letter with the OEB on April 22, 2020, advising that the utility is opting to postpone the implementation of its May 1, 2020 rates to November 1, 2020. On April 28, 2020, the OEB found that NPEI's proposal was in the public interest and issued a Vary

Order for case EB-2019-0054, where NPEI shall be authorized to implement its new rates on November 1, 2020 as requested.

STATEMENT OF CHANGES IN METHODOLOGY

1.3.11 Statement of changes in methodology

The methodologies used in this Application are generally consistent with those applied in NPEI's last Cost of Service Application (EB-2014-0096). Historical amounts are the same as approved by the Board in EB-2014-0096 except as noted in Note 21 of the 2015 Audited Financial Statements see Appendix 1-7; Explanation of transition to IFRS where the net income for 2014 was reduced by $27,501 as a result measurement and recognition differences between CGAAP (Canadian Generally Accepted Accounting Principles) and IFRS (International Financial Reporting Standards).

The $27,501 adjustment to the 2014 closing Retained Earnings is a result of the following two adjustments:

1) Increase to General & Admin Expense in the amount of $65,519 for Past Service Costs and amortization of actuarial gains no longer allowed under IFRS offset by

2) a decrease in Income Tax expense in the amount of $(38,018).

See Appendix 1-7 for the details of the 2014 IFRS conversion.

NPEI has also made changes as required as the Filing Requirements have evolved since the 2015 Cost of Service Application. This Application is prepared in accordance with MIFRS which is consistent with NPEI's last Cost of Service Rate Application in 2015.

STATEMENT OF DEVIATION FROM FILING REQUIREMENTS

1.3.12 Statement of deviation from filing requirements

There are no deviations from the filing requirements.

IDENTIFICATION OF OEB DIRECTIVES FROM PREVIOUS OEB DECISIONS

1.3.13 Identification of OEB directives from previous OEB decisions

NPEI received directions from the Board in its last cost of service rate application for 2015. In the Decision and Order dated May 14, 2015, the Conclusion stated: "The Board issued a Rate Order on April 28, 2015 declaring NPEI's existing rates interim on May 1, 2015. As a result of this Decision, new rates for 2015 will be based on the Amended Settlement Proposal, utilizing a 13% WCA. The new 2015 rates will be implemented and effective as of June 1, 2015 and remain interim, pending the results of the lead/lag study and NPEI obtaining the necessary, subsequent OEB approvals at the time of its next incentive rates application."

The Decision and Order dated May 14, 2015, on page 6, the Findings stated "The Board directs NPEI to conduct a lead/lag study and file the study with the OEB with its next incentive rates application." And "The Board directs NPEI to establish a new deferral account to capture all incremental costs associated with the study, both internal and external costs to ensure NPEI is not financially affected by the Board's directive. NPEI is also directed to file a draft accounting order with the draft Rate Order. NPEI filed a draft accounting order with the draft Rate Order in 2015 and also established a sub-account of deferral and variance account 1508 to capture the costs of the lead/lag study. Exhibit 9 provides the details with respect to this deferral and variance account as well as the disposition being requested in this Cost of Service rate application of this sub-account of 1508.

NPEI filed a lead/lag study with the OEB with the 2016 IRM rate application (EB-2015-090/EB2015-328). As a result of the OEB's findings NPEI's final WCA for 2015 is 10.48%. The Decision and Order dated March 17, 2016 ordered NPEI to calculate the amount of over-collection and propose rate riders to return the funds to its customers. On May 12, 2016, the OEB issued its Decision and Order for NPEI to repay to its customers an over-collection of $238,350 ($297,194 times 11/12ths = 272,427 less the costs incurred at the time of the application in the amount of $34,077) effective May 1, 2016. NPEI completed all directives issued by the OEB.

BOARD DIRECTION FROM PREVIOUS EDR DECISIONS

1.3.14 Board direction from previous EDR decisions

NPEI received directions from the Board in its last cost of service rate application for 2015. In the Decision and Order dated May 14, 2015, the Conclusion stated: "The Board issued a Rate Order on April 28, 2015 declaring NPEI's existing rates interim on May 1, 2015. As a result of this Decision, new rates for 2015 will be based on the Amended Settlement Proposal, utilizing a 13% WCA. The new 2015 rates will be implemented and effective as of June 1, 2015 and remain interim, pending the results of the lead/lag study and NPEI obtaining the necessary, subsequent OEB approvals at the time of its next incentive rates application."

The Decision and Order dated May 14, 2015, on page 6, the Findings stated "The Board directs NPEI to conduct a lead/lag study and file the study with the OEB with its next incentive rates application." And "The Board directs NPEI to establish a new deferral account to capture all incremental costs associated with the study, both internal and external costs to ensure NPEI is not financially affected by the Board's directive. NPEI is also directed to file a draft accounting order with the draft Rate Order. NPEI filed a draft accounting order with the draft Rate Order in 2015 and also established a sub-account of deferral and variance account 1508 to capture the costs of the lead/lag study. Exhibit 9 provides the details with respect to this deferral and variance account as well as the disposition being requested in this Cost of Service rate application of this sub-account of 1508.

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On May 12, 2016, the OEB issued its Decision and Order for NPEI to repay to its customers an over-collection of $238,350 ($297,194 times 11/12ths = 272,427 less the costs incurred at the time of the application in the amount of $34,077) effective May 1, 2016. NPEI completed all directives issued by the OEB.

CONDITIONS OF SERVICE

1.3.15 Conditions of Service

The current version of NPEI's Conditions of Service is available on NPEI's website as www.npei.ca. There are no rates or charges listed in the Conditions of Service that are not on NPEI's Tariff of Rates and Charges.

The last Conditions of Service were issued on September 30, 2019. Changes made to the 2019 version of the Conditions of Service are summarized below:

SUMMARY OF CHANGES

Version	Description	Date
Draft Version	Initial Draft	August 11, 2008
Version 2	Update of section 2.3.7.5.1 – Service Changeover	August 24, 2009
Version 3	Update and edit of Dispute process	December 29, 2009
Version 4	Mass review and update relevant to the Cost of Service Application where rates are harmonized	October 18, 2010
Version 5	Update of Specific Service Charges Section 2.4.1.3	Feb 8, 2011
Version 6	Review and update of document to current	June 10, 2014
Version 7	Updated customer classifications	February 12, 2015

Version 8	Updated Disconnection Notification	June 2, 2015
Version 8	Updated Preface and Section 2.2.2	March 7, 2016
Version 9-10	Updated Payment Section 2.4.5.1	January 8, 2018
Version 11	Updated Payment Section 2.4.5.1	January 9, 2018
Version 12	Updated Sections 2.1.1, 2.1.2, 2.6.7, 3.1, 3.2 & 5.3 to clarify Standard Connection Allowance and Variable Connection Costs	May 1, 2019
Version 13	Preface: Removed Fax Number as method of contact due to privacy and security of customer information Section 1.3: Removed Green Energy Act as it was repealed January 1, 2019; Updated to include updates from Customer Service Rules: Section 2.2.2 Updates relative to disconnection to include details of timeline, business process as it relates to low income and delivery of 48 hour notice by phone. Section 2.4.5.1 Updated acceptable methods of payments. Equal Payment Plan Section 2.8 Service Changeovers - Opening and Closing of Accounts;	July 5, 2019 July 23, 2019
Version 14	Updated Customer Service Rules for Disconnection Notice and Deposit effective March 1, 2020, Updated Section 2.1 Connection, 2.2 Disconnection, 2.3.5 Metering, 2.4.1 Service Connections, Section 2.4.3 Deposits, Section 2.4.4 Billing, Section 2.6.5 Payments and Late Payment Charge	September 23, 2019

As a result of the changes, the final version of Conditions of Service for 2019 can be found using the following link:

https://www.npei.ca/online-resources/conditions-of-service

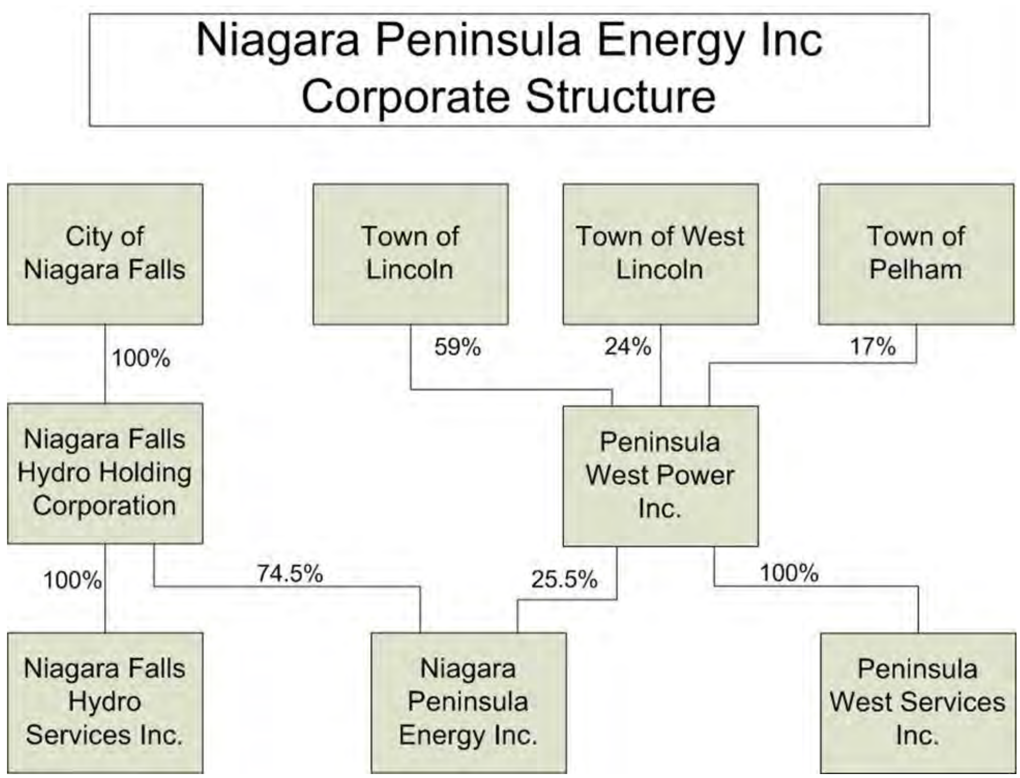
NPEI confirms that there are no rates and charges linked in the Conditions of Service that are not in the distributor's Tariff of Rates and Charges.

DESCRIPTION OF CORPORATE STRUCTURE

1.3.16 Description of Corporate Structure

NPEI's Corporate Entities chart is below in Chart 1-1 and its Utility Organization chart is below in Chart 1-2. There are no planned changes to either the Corporate Entities chart or the utility organization chart.

Chart 1-1 NPEI's Corporate Entities Chart



As per the Shareholders Agreement (Appendix 1-13) NPEI's Board consists of four members appointed by Niagara Falls Hydro Holding Corporation and four members appointed by Peninsula West Power Inc. Currently in 2019, two members of NPEI's Board of Directors are affiliated with Niagara Falls Hydro Holding Corporation as both are members of the Niagara Falls Hydro Holding Corporation's Board of Directors. No other members of NPEI's Board of Directors are affiliated with the Shareholders.

UTILITY ORGANIZATION STRUCTURE

1.3.17 Utility organization structure

Niagara Peninsula Energy's organization structure is shown in Appendix 1-9 of this exhibit. The Senior Executive Management structure is shown in Appendix 1-10 of this exhibit.

ACCOUNTING STANDARDS FOR REGULATORY AND FINANCIAL REPORTING

1.3.18 Accounting Standards for regulatory and financial reporting

NPEI adopted International Financial Reporting Standards (IFRS) effective January 1, 2015. NPEI adopted Modified International Financial Reporting Standards (MIFRS) for rate making purposes effective January 1, 2015 and follows the OEB's Accounting Procedures Handbook (APH).

NPEI adopted the required accounting changes for depreciation and capitalization policies on January 1, 2013.

NPEI has provided the 2014 through 2019 Actuals, the 2020 Bridge and 2021 Test Year under MIFRS unless otherwise noted.

The 2015 Audited Financial Statements were prepared in accordance with IFRS, with 2014 comparative information restated under IFRS. The 2015 Cost of Service Application was prepared on a MIFRS basis. As well, the 2021 Cost of Service is prepared on a MIFRS basis.

STATUS UPDATE ON IMPLEMENTATION OF NEW ACCOUNTING GUIDANCE

1.3.19 Status update on implementation of new accounting guidance

On July 20, 2018, the OEB issued a letter to all rate-regulated licensed electricity distributors, advising them that the OEB is undertaking an initiative to standardize the accounting processes used by distributors relating to Regulated Price Plan (RPP) wholesale settlements. This letter stated that, effectively immediately, the OEB will not be approving Group 1 rate riders on a final basis pending the development of this further guidance.

On February 21, 2019, the OEB issued its Accounting Procedures Handbook Update-Accounting Guidance Related to Commodity Pass-Through Accounts 1588 & 1589, outlining standardized requirements for regulatory accounting and RPP settlements that all distributors are expected to follow (Accounting Guidance). The Accounting Guidance is effective January 1, 2019, and was to be implemented by August 31, 2019.

In the OEB's *Addendum to filing Requirements for Electricity Distribution Rate Applications-2020 Rates* (the 2020 Filing Requirements Addendum), under Section 3.2.5.3, the OEB stated that, for 2020 rate applications, distributors are to provide a status update on the implementation of the new Accounting Guidance, a review of historical balances, results of the review, and any adjustments made to account balances. The 2020 Filing Requirements Addendum also states the following expectations for final disposition requests of commodity pass-through account balances:

- Any historical balances that were previously approved on an interim basis, or not approved at all, including the 2018 balances, have been reviewed in the context of the Accounting Guidance and are confident that there are no systemic issues with their RPP settlement and related accounting processes affecting those balances

- Any historical balances that were previously not approved by the OEB due to concerns noted have been assessed in the context of the updated Accounting Guidance. Any necessary revisions or adjustments made are documented, discussed in detail, quantified, and provided to the OEB for review prior to request for final disposition.

In the 2019 IRM rate application, Niagara Peninsula Energy's 2017 commodity pass-through account balances were approved for disposition on an interim basis as the account balances were justified and were reasonable. In the 2020 IRM rate application, EB-2019-0054, NPEI confirmed that it has considered the Accounting Guidance and is of the view that no adjustments to the 2017 and 2018 balances are required and has requested the disposition of the 2017 and 2018 account balances be approved on a final basis. Also, in the 2020 IRM rate application NPEI applied for the disposition of the 2018 commodity pass-through balances. In the Decision and Order dated December 12, 2019, by the OEB, the findings by the OEB approved the disposition of the 2017 and 2018 balances for Group 1 on a final basis.

In this 2021 COS rate application NPEI is applying for disposition of the 2019 commodity pass-through account balances.

NPEI confirms it has considered the Report of the Ontario Energy Board, Regulatory Treatment of Pension and Other Post-Employment Benefits (OPEBs) Costs dated September 14, 2017, EB-2015-0040, Appendix C. See Exhibit 9 for details.

NPEI confirms it has considered the Accounting Guidance for Wireline Pole Attachment Charges dated July 20, 2018. See Exhibit 9 for details.

NPEI confirms it has considered the Decision and Order, EB-2015-0304, Energy Retailer Service Charges effective May 1, 2019, dated February 14, 2020 in its application. See Exhibit 9 for details.

NPEI confirms it has considered the new Micro-fit monthly service charge effective January 1, 2021 as per the letter from the OEB, dated February 24, 2020.

CONFIDENTIALITY

1.3.20 Confidentiality

NPEI has provided redacted versions of the 2018 and 2019 Income Tax returns. The employee's names listed on Schedules 550 and 552 have been redacted for privacy reasons. The 2018 Income Tax return is included in Appendix 4-5 and the 2019 Income Tax return is included in Appendix 4-13.

The names of the employees have been redacted on the basis of personal information. The redacted information has limited relevance to the COS application and will not hinder the OEB's ability to hear the application in a transparent and open manner. The information relates to individual, identifiable employees and their earnings, and disclosure of such information is restricted by the Freedom of Information and Protection of Privacy Act. The information of salaries is clearly personal information when the employee's names are also presented. NPEI has only redacted the employee's names as noted above. NPEI notes that similar information has been held to be confidential in previous OEB's proceedings and NPEI requests the OEB

CORPORATE GOVERNANCE

1.3.21 Corporate Governance

On June 22, 2016, the Ontario Energy Board (OEB) initiated a consultation to develop guidance on corporate governance for OEB rate-regulated utilities (EB-2014-0255). The final Board Report was issued on December 20, 2018. NPEI has been actively monitoring developments with regards to this consultation and has been preparing its Board for any upcoming changes and reporting requirements. A corporate governance project was initiated by the Board of Directors in 2019 in response to the OEB's Draft report on Governance Best Practices. NPEI's Governance Committee undertook a full review of its Corporate Governance. In Appendix 1-11, NPEI has provided its updated Corporate Governance Introduction and Overview. Appendix 1-11 details NPEI's Corporate Governance Board of Director Policies and Appendix 1-11 relates to NPEI's Board of Directors Roles & Responsibilities and Committee Terms of Reference.

NPEI's Board of Directors consists of eight members, of which four are appointed by Niagara Falls Hydro Holding Corporation which owns 74.5% of the shares in NPEI and four are appointed by Peninsula West Power Inc. which owns 25.5% of the shares in NPEI. Six of the eight directors are independent and are not Boards of Directors on either of the two shareholder Boards.

1.3.21.1 Board Mandate

The Shareholder's Agreement outlines the expectations of the Shareholders relating to the guiding principles and objectives, financial policies, risk management, strategic plan, and permitted business activities. In December 2019, NPEI's Board of Directors approved the updated Corporate Governance documents found in Appendices 1-22-1, 1-22-2 and 1-22-3. The Board of Directors is responsible for overseeing the business and affairs of the Corporation; and ensuring that NPEI conducts the affairs in accordance with the Shareholder's Agreement, subject to licenses, codes, policies, rules, orders, interim orders, approvals, consents and other actions of any regulatory and all other legal requirements.

The Roles and Responsibilities of the Board of Directors, the Chair of the Board, the Vice-Chair of the Board, the Board Secretary, the Chair of the Governance Committee and the Chair of the Finance Committee are detailed in Appendix 1-22-3.

1.3.21.2 Board Meetings

The NPEI Board of Directors meets at a minimum once per quarter. The schedule of Board Meetings for 2019 and 2020 is

2019	**2020**
February 12, 2019	February 18, 2020
April 9, 2019	April 14, 2020
July 9, 2019	June 2, 2020
September 10, 2019	September 8, 2020
December 3, 3019	October 20, 2020
	December 8, 2020

1.3.21.3 Board of Directors Standard of Conduct

NPEI's Board of Directors has a Standard of Conduct Policy. The Standard of Conduct Policy provides for the conduct for members of the Corporation's Board of Directors. The Standard of Conduct Policy provides direction of conflict of interest matters, loyalty and confidentiality, and duty to disclose. See Appendix 1-22-2 Board of Directors Policies.

1.3.21.4 Board Committees

There are currently two committees of the NPEI Board of Directors including:

1. Governance Committee and
2. Finance Committee

The Governance Committee's primary role is to establish process and practices to enable the Board of Directors in delivering effective governance of the organization. The objectives of the Committee are to assist the Board in fulfilling its oversight responsibilities and to hold directors and Board committees accountable to fulfilling their duties.

The Finance Committee's principal role is to ensure that due diligence is directed towards verifying that an effective risk management and control framework has been implemented by management. This framework is to provide reasonable assurance that the financial, operational and regulatory objectives of the Company are achieved and that the governance and accountability responsibilities of the Board and management are met.

Both committees shall be comprised of no less than four (4) members of the Board. The Governance Committee shall meet as required and the Finance Committee meets at a minimum twice per year. Once in April to review the audited financial statements and once in November or December to review the following years operating and capital budgets. Additional meetings shall be held as required.

1.3.21.5 Orientation and Continuing Education

All new Directors of NPEI receive a comprehensive orientation with respect to the organizational structure, the role of the Board, the business plan, budget, financial statements, rate tariffs and the legislative and regulatory environment affecting the electricity sector. A special Board meeting is held specifically for Board orientation.

NPEI utilizes an on-line board portal for all Board of Directors and Committee materials. Included as part of the web-portal are previous Board and Committee agendas and meeting materials, and communications from the EDA weekly and wire scans.

Board members are also encouraged to participate in industry events and conferences, including the EDA's Directors Summit, EDIST (Technical), Enercom, EBIC (Innovation), MEARIE conference and the Women Connected series of events.

SHAREHOLDERS AGREEMENT

1.3.22.1 Shareholders agreement

NPEI's shareholder agreement dated January 1, 2008 is between Niagara Falls Hydro Holding Corporation, Peninsula West Power Inc. and Niagara Peninsula Energy Inc. The Shareholder's Agreement outlines the expectations of the Shareholders relating to the principles of corporate governance. See Appendix 1-13 for a copy of the Shareholder's Agreement. There have been no changes to this Agreement.

The Shareholders Agreement also provides for the following:

- Composition of the Board
- Term of the Board
- Qualifications for the Board of Directors
- Meeting of Directors
- Unanimous Approval by Shareholders
- Special Resolution by Shareholders

As mentioned in section 1-21 Corporate Governance, the Board of Directors of NPEI consists of eight Directors of which six are independent. The two Directors that are not independent include: (2) Councilors of the City of Niagara Falls which are also member of the Niagara Falls Hydro Holding Corporation Board of Directors. The Chair of the Board is an independent Director, as are the Chairs of the Governance Committee and the Finance Committee.

APPROVALS REQUESTED

1.3.23 Approvals requested

In this proceeding, NPEI is requesting the following approvals:

1. Approval to align NPEI's rate year to its fiscal and budget year with rates changing from May 1st to January 1st, effective January 1, 2021.
2. Approval to charge distribution rates effective January 1, 2021 to recover a service revenue requirement of $37,840,675 which includes a revenue deficiency of $2,395,224 as detailed in Exhibit 6. The schedule of proposed rates is set out in Exhibit 8.
3. Approval to adjust the Retail Transmission Rates-Network and Connection as detailed in Exhibit 8.
4. Approval to adjust the Low Voltage rates as detailed in Exhibit 8.
5. Approval of the proposed Loss Factors as detailed in Exhibit 8.
6. Approval to continue to use the Transformer Allowance and Primary Metering Allowance for transformer losses.
7. Approval of the rate riders for disposition of the Group 1 and Group 2 Deferral and Variance Accounts as detailed in Exhibit 9.
8. Approval of the rate rider for disposition of Impacts arising from the COVID-19 Emergency, sub-account - Foregone Revenues from Postponing rate implementation
9. Approval to dispose and discontinue the use of the following Deferral and Variance Accounts:
    a. Lead/Lag Study Variance Account-sub-account 1508
    b. Incremental Capital Charges (Hydro One) Variance Account-sub-account 1508
    c. Wireline Pole Attachments Variance account-sub-account 1508
    d. RCVA Variance Account-Account 1518

e. RCVA (STR) Service Transaction Variance Account-Account 1548
f. Stranded Meter Variance Account-Account 1555
g. Mist Meter Reading Variance Account-Account 1557
h. Accounting Changes under CGAAP-Account 1576

10. Approval of the rate rider for a one-year disposition of the Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) for lost revenue as presented in Exhibits 4 and 9 of this Application.
11. Approval of the micro-FIT service classification and monthly service charge proposed in Exhibit 8.
12. Approval of the Specific Service Charges proposed in Exhibit 8. NPEI is not requesting any changes to its current Specific Service Charges.
13. Approval of the Retail Service Charges proposed in Exhibit 8. NPEI is not requesting any changes to its current Retail Service Charges.

NPEI has completed the OEB Appendix 2-A List of Requested Approvals, which is included in Appendix 1-1.

2021 COS CHECKLIST USED FOR 2021 COS RATE APPLICATION

1.3.24 2021 COS checklist used for 2021 COS rate application

NPEI has included the 2021 COS checklist used for 2021 COS rate application in Appendix 1-14.

Exhibit 1: Administrative Documents

Tab 4 (of 10): Distribution System Overview

DESCRIPTION OF SERVICE AREA

1.4.1 Description of Service Area

Description of Distributor: Niagara Peninsula Energy Inc.

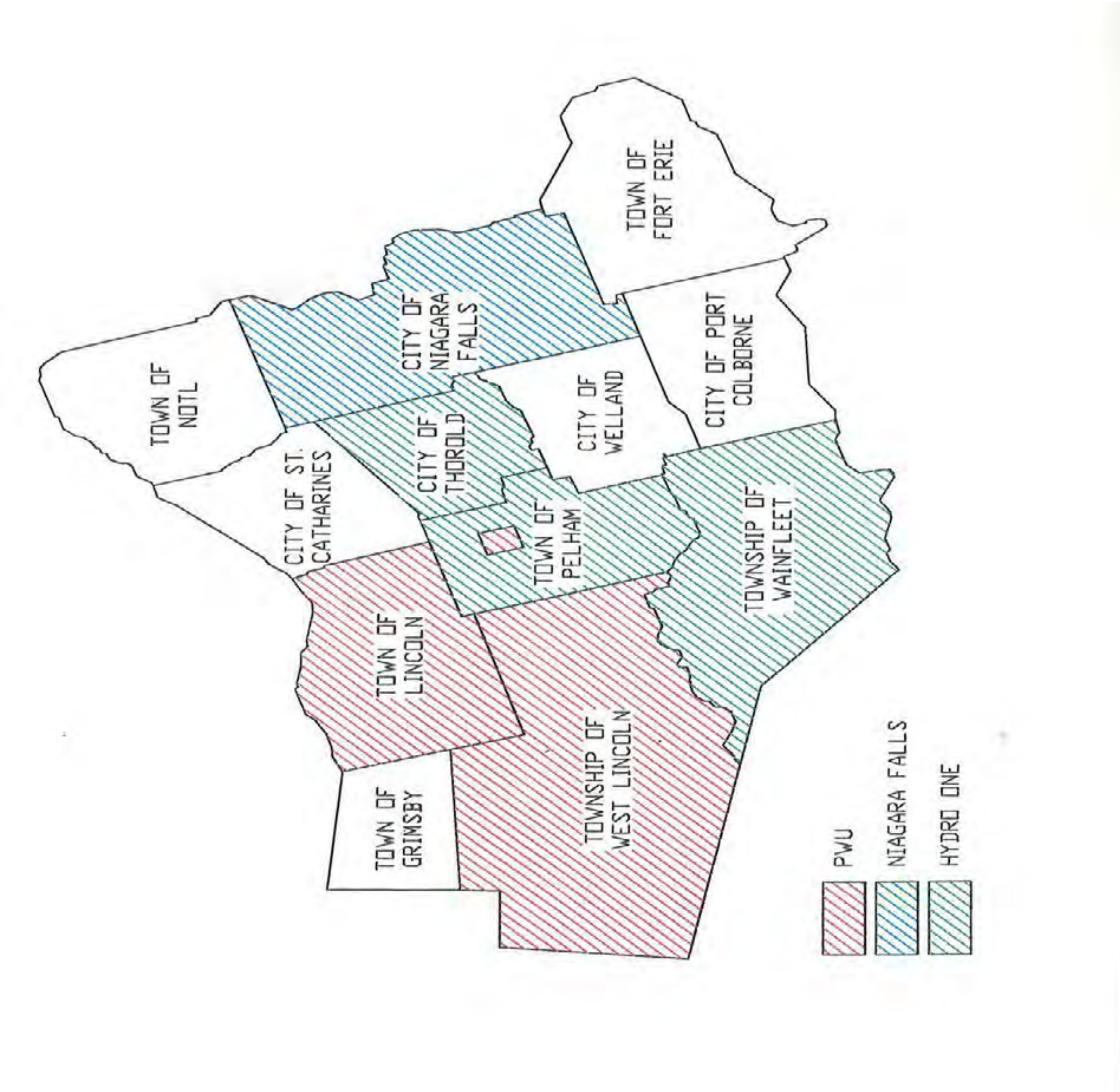
COMMUNITY SERVED:	City of Niagara Falls, Town of Lincoln Township of West Lincoln Town of Pelham
TOTAL SERVICE AREA:	827 sq km
URBAN SERVICE AREA:	68 sq km
RURAL SERVICE AREA:	759 sq km
DISTRIBUTION TYPE:	Electricity distribution
Overhead km of line	1,456
Underground km of line	582
Total km of line	2,038

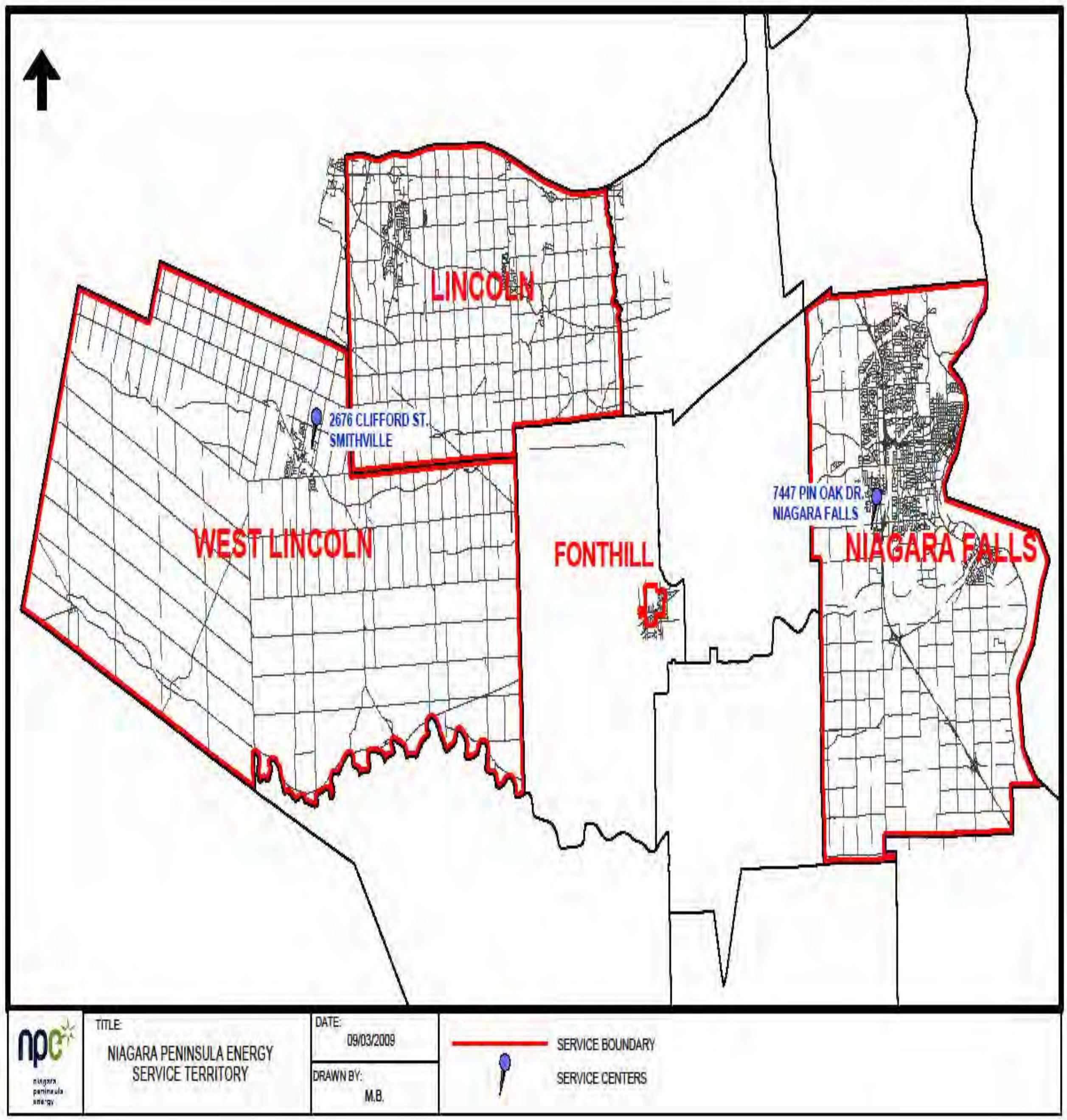
A map of the NPEI's Distribution Service Territory accompanies this Schedule as Map 1-1.

A schematic diagram of NPEI's distribution system is attached in Maps 1-2, 1-3, 1-4 and Map 1-5.

MAP OF DISTRIBUTION SERVICE TERRITORY

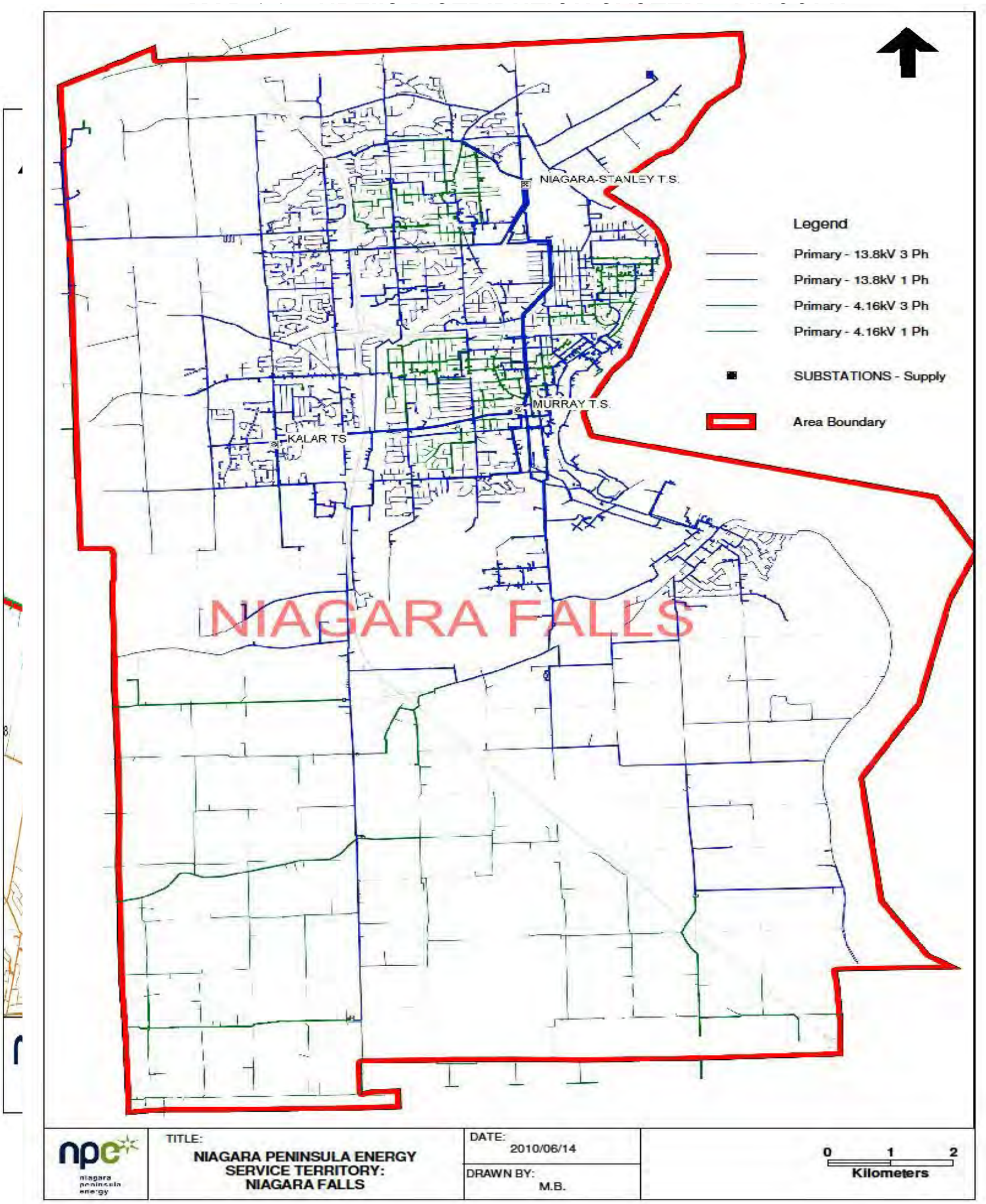
The outlined area represents the City of Niagara Falls, the Town of Lincoln, the Township of West Lincoln and the Town of Pelham. See Map 1-1 below.



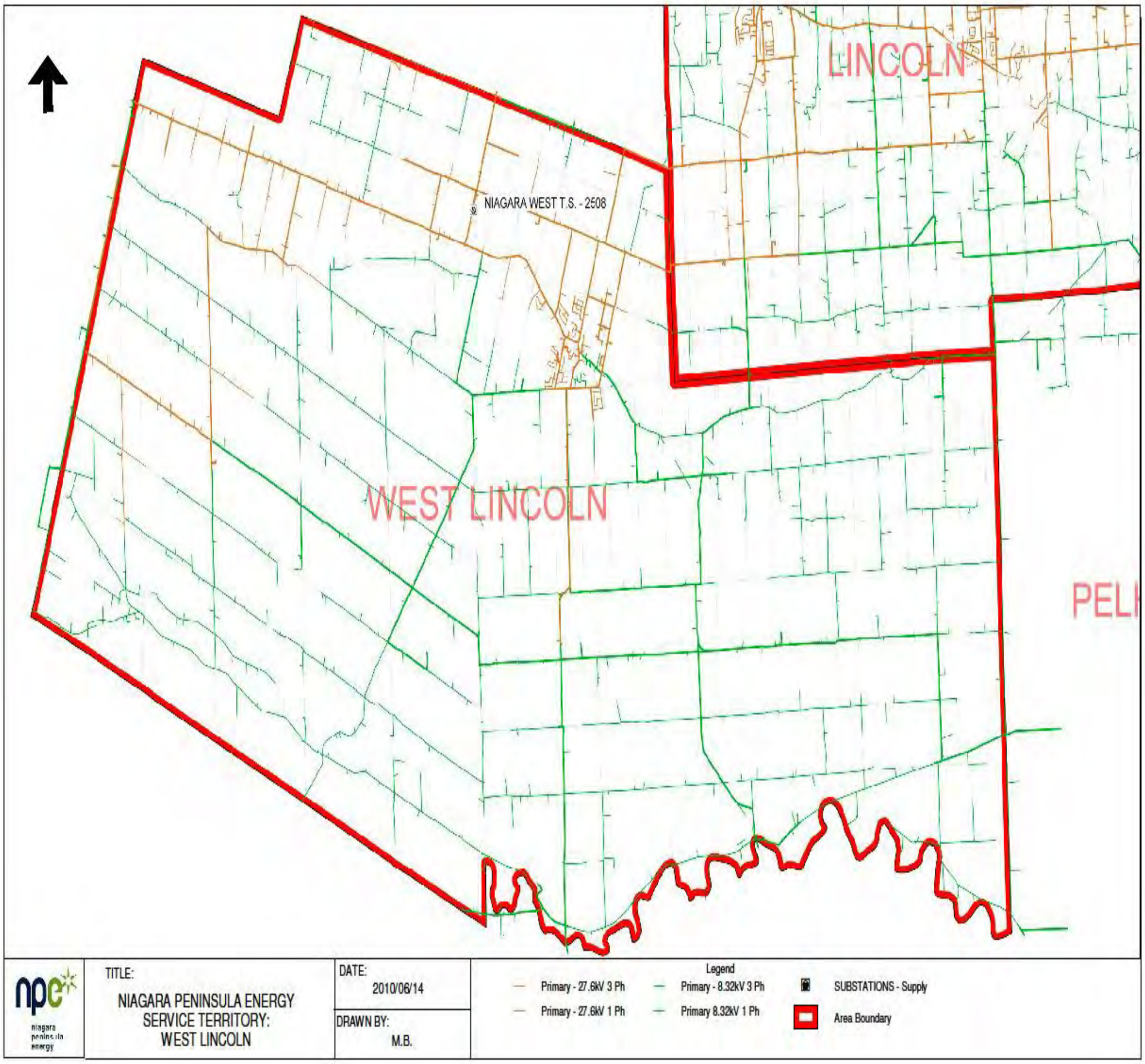

LINCOLN
2676 CLIFFORD ST.
SMITHVILLE
WEST LINCOLN
FONTHILL
7447 PIN OAK DR.
NIAGARA FALLS
NIAGARA FALLS
npe
niagara peninsula energy
TITLE:
NIAGARA PENINSULA ENERGY
SERVICE TERRITORY
DATE:
09/03/2009
DRAWN BY:
M.B.
SERVICE BOUNDARY
SERVICE CENTERS

MAP 1-2 – NPEI'S DISTRIBUTION SYSTEM – NIAGARA FALLS

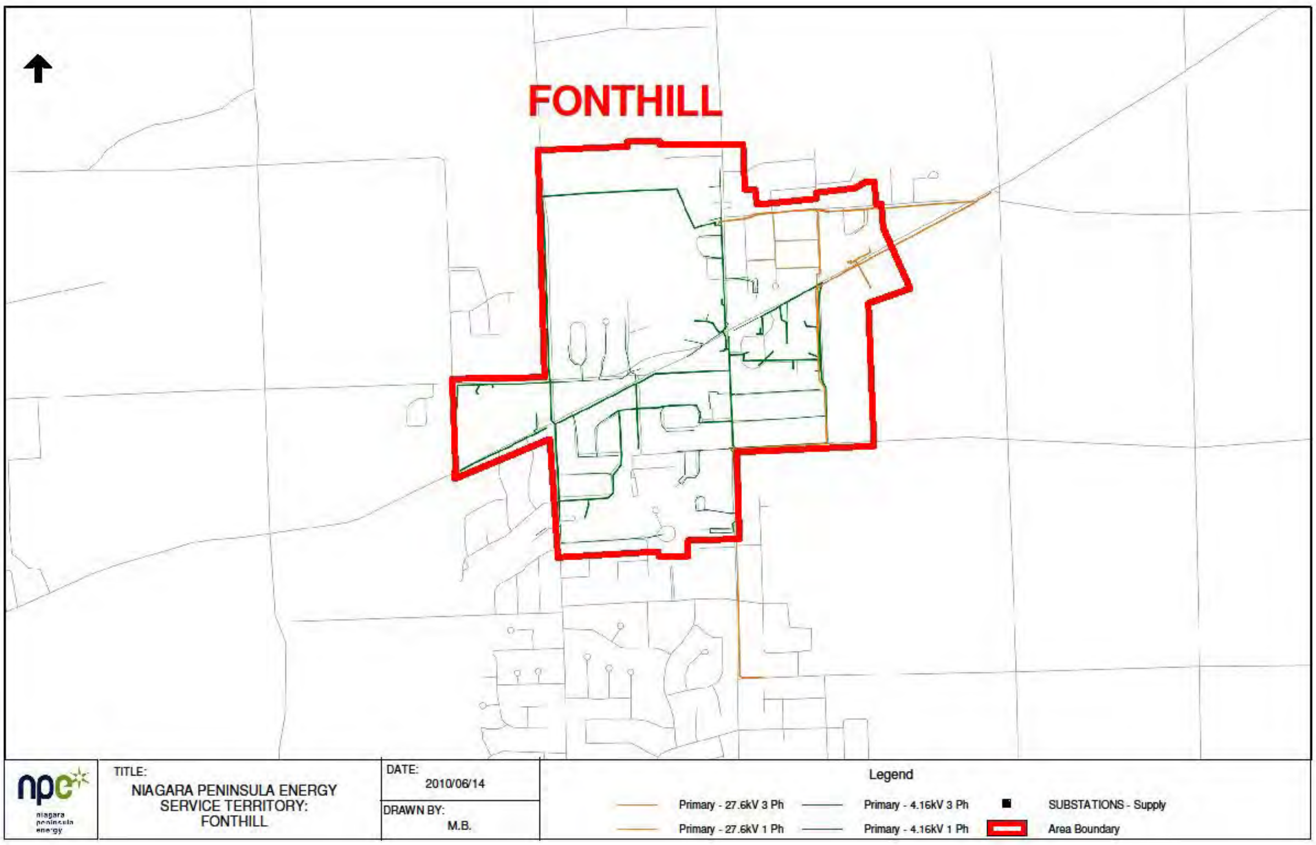
MAP OF DISTRIBUTION SYSTEM


NIAGARA-STANLEY T.S.
MURRAY T.S.
KALAR TS
NIAGARA FALLS
Legend
Primary - 13.8kV 3 Ph
Primary - 13.8kV 1 Ph
Primary - 4.16kV 3 Ph
Primary - 4.16kV 1 Ph
SUBSTATIONS - Supply
Area Boundary
npe
niagara peninsula energy
TITLE:
NIAGARA PENINSULA ENERGY SERVICE TERRITORY: NIAGARA FALLS
DATE:
2010/06/14
DRAWN BY:
M.B.
0 1 2
Kilometers

MAP 1-4 – NPEI'S DISTRIBUTION SYSTEM – WEST LINCOLN



MAP 1-5 – NPEI'S DISTRIBUTION SYSTEM – FONTHILL



NPEI's Distribution System Description

NPEI owns and operates the electricity distribution system in its licensed service area in the City of Niagara Falls, the Town of Lincoln, the Townships of West Lincoln and the Town of Pelham, serving approximately 56,100 Residential, General Service, Street Light, Sentinel and Unmetered Scattered Load customers.

NPEI's distribution assets include one (1) Transformer Station (TS) that steps voltage down from 115kV to 13.8kV for distribution in the City of Niagara Falls. NPEI constructed, owns, and has maintained its TS since 2004. This new TS was approved to be a deemed distribution asset in the 2006 EDR rate application. The TS was built over a two-year period from 2003 to 2004 and as a result, half of the addition costs were included in the rate base for the 2006 EDR rate application. The remaining portion was included in the 2011 Cost of Service rate application.

In addition, NPEI receives power from two (2) Hydro One 115/13.8kV TS's, one (1) Hydro One 115/27.6kV TS, one (1) Hydro One 115/27.6kV Distribution Station (DS), one (1) Hydro One 27.6/8.32kV DS, three (3) Hydro One 27.6kV feeders, and (1) 230kV/27.6kV TS owned by Grimsby Hydro.

NPEI also owns and operates ten (10) 13.8kV/4.16kV Municipal Stations (MS's), four (4) 27.6kV/8.32kV DS's, and two (2) 27.6kV/4.16kV DS's.

Electricity is then distributed through NPEI's service area of 827 square kilometers through over 582 kilometers of underground cable and 1,456 kilometers of overhead conductor. Voltage is stepped down from the primary feeders through approximately 9,888 LDC owned distribution transformers.

NPEI's overhead distribution system accounts for approximately sixty-seven percent of its overall distribution system. This portion of the distribution system is comprised of more than 39,008 poles, 1,456 km of overhead lines and all associated distribution transformers (6,596) and protective devices.

NPEI's underground distribution system accounts for approximately, thirty-three percent of its overall distribution system. This portion of the distribution system is comprised primarily of 582 km of underground conductors and all associated distribution transformers (3,292) and protective devices.

On December 21, 2015, the Ontario Energy Board (OEB) issued a Notice of Amendments to the Code—Amendments to the Distribution System Code (EB-2015-0006), related to the Elimination of Load Transfer Arrangements between electricity distributors (LDC's). The OEB set an objective of eliminating Load Transfer Arrangements by June 21, 2017. NPEI had six Load Transfer Arrangements to complete. NPEI completed the service area amendments and asset transfers for Load Transfer Arrangements with Welland Hydro, Canadian Niagara Power, Niagara-on-the-Lake Hydro, Alectra Utilities and Grimsby Hydro by June 21, 2017.

NPEI and Hydro One filed a joint service area amendment on December 12, 2019. NPEI and Hydro One's joint application was approved by the OEB on March 12, 2020

NPEI monitors its distribution system through a supervisory control system at its main office. Hydro One operates the Supervisory Control and Data Acquisition ("SCADA") system twenty-four hours a day, seven days a week. NPEI owns and maintains approximately 55,200 meters installed on its customers' premises for the purpose of measuring consumption of electricity for billing purposes. Meters vary in type by customer and include meters capable of measuring kWh consumption, kW and kVA demand as well as hourly interval data. NPEI completed the installation of Smart Meters as part of the Province of Ontario's smart meter initiative. NPEI's smart meter rate application for final disposition EB-2013-0359 was approved February 27, 2014.

A letter date May 21, 2014, from the OEB 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 came into force August 21, 2014.

NPEI will have completed the conversion from conventional meters to MIST meters by the end of May 2020. NPEI will complete the conversion of the remaining conventional meters to smart meters for any General Service < 50 kW customer by the end of the second quarter in 2020.

In managing its distribution system assets, NPEI's main objective is to optimize performance of the assets at a reasonable cost with due regard for system reliability, public and worker safety, and customer service requirements. This Application incorporates NPEI's 2021 Capital and OM&A Expense Budgets in determining the revenue requirement to bring these plans to fruition. NPEI considers performance related asset information including, but not limited to, data on reliability, asset age and condition, loading, customer connection requirements, system configuration, and any other customer needs to determine investment needs of the system.

LIST OF NEIGHBORING UTILITIES

1.4.2 List of Neighboring Utilities

NPEI is bounded by the following neighboring utilities:

Canadian Niagara Power
Welland Hydro
Niagara-on-the Lake Hydro
Hydro One
Alectra Utilities
Grimsby Hydro

DESCRIPTION OF EMBEDDED / HOST DISTRIBUTOR RELATIONSHIPS

1.4.3 Description of embedded/host distributor relationships

There are no embedded utilities within NPEI's distribution service territory nor is NPEI a host utility to other distributors.

STATEMENT OF DEEMED TRANSMISSION / HIGH VOLTAGE ASSETS

1.4.4 Statement of deemed transmission/high voltage assets

NPEI confirms that it does have transmission assets (i.e. assets operating at greater than 50 kV) in its distribution system that had previously been deemed by the Board as distribution assets. NPEI constructed a transformer station on Kalar Road in Niagara Falls over a two-year period from 2003 to 2004 and as a result, half of the addition costs were included in the rate base for the 2006 EDR rate application. The remaining portion was included in the 2011 Cost of Service rate application. This transformer station was approved to be a deemed distribution asset in the 2006 EDR rate application. NPEI does not have any other transmission assets being requested to be deemed distribution assets in this Application.

Exhibit 1: Administrative Documents

Tab 5 (of 10): Application Summary

APPLICATION SUMMARY

1.5.1.1 Application Summary

Table 1.5.1.1-1 below lists the main elements of this Application which are further discussed in the Application.

Table 1.5.1.1-1 Application Summary

	2021 Test Year
Revenue Requirement	
Service Revenue Requirement	37,840,675
Revenue Offsets	2,971,337
Base Revenue Requirement	34,869,338
Revenue Deficiency	2,395,224
OM&A (exluding Property Taxes)	20,120,915
Depreciation	8,442,650
Property Taxes	263,095
Deemed Interest Expense	2,887,958
PILS	334,085
Target Return on Equity	5,791,971
Service Revenue Requirement	37,840,675
Rate Base	169,952,205
Working Capital	13,329,650
Capital Expenditures	17,377,598
Capital Contributions	(2,583,228)
Net Capital Expenditures	14,794,371

1.5.1.2 Revenue Requirement

NPEI's requested Service Revenue Requirement for the 2021 Test Year is $37,840,675 which provides for the recovery of the following:

- Operations, Maintenance and Administration Expenses;
- Property Taxes;
- Depreciation/Amortization Expense;
- Payments in Lieu of Income Taxes; and
- Return on Rate Base (Debt Interest Expense + Return on Equity)

The Service Revenue Requirement represents an increase of $6,966,823 or 22.3% over the 2015 Board Approved with a WAC at 10.48% amount of $30,873,852. Note the amortization of capital contributions was netted against depreciation in 2015. The implementation of IFRS in 2015 has changed the presentation, whereby amortization of capital contributions is presented with Other Revenue and hence is included in Revenue Offsets for the 2021 Test Year. For comparison purposes, the 2015 Board Approved Revenue Requirement was restated to gross up depreciation expense and revenue offsets in the amount of $903,332.

Table 1.5.1.2-1 below compares the revenue calculations to the 2015 Board Approved and the 2021 Test Year.

Table 1.5.1.2-1 Revenue Requirement Comparison 2021 to 2015

	2015 Board Approved WCA at 10.48%	2021 Test Year	$ Change	% Change
Gross Average Fixed Assets	246,244,429	314,442,219	68,197,790	27.7%
Average Accumulated Depreciation	(123,110,940)	(157,819,664)	(34,708,724)	28.2%
Average Net Fixed Assets	123,133,489	156,622,556	33,489,067	27.2%
Allowance for Working Capital	16,828,225	13,329,650	(3,498,575)	-20.8%
Total Rate Base	**139,961,714**	**169,952,205**	**29,990,491**	**21.4%**
Working Capital Allowance	10.48%	7.50%	-2.98%	
Regulated Return on Capital	8,402,294	8,679,929	277,635	3.3%
OM&A including Property Taxes	16,424,995	20,384,010	3,959,015	24.1%
Amortization Expense	5,937,406	8,442,650	2,505,244	42.2%
PILS	109,157	334,085	224,928	206.1%
Service Revenue Requirement	30,873,852	37,840,675	6,966,823	22.6%
Less: Revenue Offsets	2,505,854	2,971,337	465,483	18.6%
Base Revenue Requirement	28,367,998	34,869,338	6,501,340	22.9%

Based on the projected load forecast and customer growth for the 2021 Test Year, as provided for in this Application, NPEI has estimated a revenue deficiency of $2,395,224 or 6.76% based on its current rates. The computation of the revenue deficiency is shown in Table 1.5.1.2-2 below, as provided in Exhibit 6, section 6.1.

Table 1.5.1.2-2 Calculation of Revenue Deficiency 2021 versus 2015

Service Revenue Requirement	2015 Board Approved	2021 Revenue at Existing rates	2021 Proposed	Revenue Deficiency	% Change
	(A)	(B)	(C)	(D)	
OM&A including LEAP	16,137,763	18,527,338	20,120,915	1,593,576	8.60%
Depreciation	5,937,406	6,816,579	8,442,650	1,626,072	23.85%
Property Taxes	287,232	329,763	263,095	(66,668)	-20.22%
Return on Rate Base	5,206,576	5,977,532	5,791,971	(185,561)	-3.10%
PILS	109,157	125,320	334,085	208,765	166.59%
Deemed Interest	3,195,718	3,668,919	2,887,958	(780,961)	-21.29%
Total	30,873,852	35,445,452	37,840,675	2,395,224	6.76%
			Difference (D) = (C) - (A)		
Rate Base	139,961,714		169,952,205	29,990,491	21.43%

Table 1.5.1.2-3 illustrates the comparison of the revenue deficiency by component between the 2021 Test Year and the 2015 Board Approved.

Table 1.5.1.2-3 Revenue Deficiency 2021 versus 2015 by component

Service Revenue Requirement	2015 Board Approved	2021 Proposed	Revenue Deficiency	% Change
	(A)	(C)	(D)	
OM&A including LEAP	16,137,763	20,120,915	3,983,152	24.68%
Depreciation	5,937,406	8,442,650	2,505,244	42.19%
Property Taxes	287,232	263,095	(24,137)	-8.40%
Return on Rate Base	5,206,576	5,791,971	585,395	11.24%
PILS	109,157	334,085	224,928	206.06%
Deemed Interest	3,195,718	2,887,958	(307,760)	-9.63%
Total	30,873,852	37,840,675	6,966,823	22.57%
		Difference (D) = (C) - (A)		
Rate Base	139,961,714	169,952,205	29,990,491	21.43%

The revenue deficiency of $2,395,224 for the 2021 Test Year is principally as a result of increases in the following components:

- Increase in OM&A
- Increased depreciation
- Increase in PILS

The following components have decreased since the 2015 COS rate application that offset the above noted increases:

- Decrease in Property Taxes
- Decrease in Return on Rate Base
- Decrease in Deemed Interest

The factors that have increased are further explained below: Depreciation has increased as a result of the increase in net fixed assets in service. The 2015 Board approved average net fixed assets was $123,133,489 compared to $156,622,556 in the 2021 Test Year (Exhibit 2). Details with respect to the increases in the net fixed assets is provided in evidence in Exhibit 2.

PILS has increased as a result of higher utility income before taxes (Exhibit 4). Utility income before taxes in 2015 was $5,315,733 compared to $6,126,057 in the 2021 Test Year. Table 1.5.1.2-4 below details the Utility income before taxes for both 2015 COS Board Approved and the 2021 Test Year.

Table 1.5.1.2-4 – Utility Income before PILS

	2015 Board Approved WCA at 10.48%	2021 Test Year	$ Change	% Change
Operating Revenue:				
Distribution Revenue (at Proposed Rates)	28,367,998	34,869,338	6,501,340	22.92%
Other Revenue	2,505,854	2,971,337	465,483	18.58%
Total Revenue	**30,873,852**	**37,840,675**	6,966,823	22.57%
Operating Expenses				
OM&A Expenses	16,137,763	20,120,915	3,983,152	24.68%
Depreciation/Amortization	5,937,406	8,442,650	2,505,244	42.19%
Property Taxes	287,232	263,095	- 24,137	-8.40%
Total Expenses before Interest	**22,362,401**	**28,826,660**	**6,464,259**	**28.91%**
Deemed Interest Expense	3,195,718	2,887,958	- 307,760	-9.63%
Total Expenses	**25,558,119**	**31,714,619**	**6,156,500**	**24.09%**
Utility income before income taxes	5,315,733	6,126,057	810,324	15.24%
Income taxes (grossed-up)	109,157	334,085	224,928	206.06%
Utility Net Income	**5,206,576**	**5,791,971**	**585,395**	**11.24%**

The return on rate base has increased $585,395 as a result of an increase in total Rate Base of $29,990,491 (Exhibit 2). Table 1.5.1.2-5 below illustrates the comparison in Total Rate Base between the 2021 Test Year and the 2015 Board Approved Rate Based

Table 1.5.1.2-5 Rate Base comparison 2021 Test Year versus 2015 Board Approved

	2015 Board Approved WCA at 10.48%	2021 Test Year	$ Change	% Change
Gross Average Fixed Assets	246,244,429	314,442,219	68,197,790	27.70%
Average Accumulated Depreciation	(123,110,940)	(157,819,664)	(34,708,724)	28.19%
Average Net Fixed Assets	123,133,489	156,622,556	33,489,067	27.20%
Allowance for Working Capital	16,828,225	13,329,650	(3,498,575)	-20.79%
Total Rate Base	**139,961,714**	**169,952,205**	**29,990,491**	**21.43%**

The increase in average net fixed assets was $33,489,067 and is offset by a reduction in the working capital allowance of $3,498,575. The Working Capital Allowance has decreased as a result of a reduction in the working capital allowance percentage from 10.48% to 7.5% based on the Board approved working capital allowance. Included in the working capital is the Cost of Power, which is also lower due to the implementation of the Ontario Electricity Rebate of 31.8% effective November 2019, which has reduced commodity prices (Exhibit 2).

2021 Test Year OM&A expenses, including LEAP donation, have increased from 2015 Board approved and are discussed thoroughly in Exhibit 4.

1.5.1.3 Budgeting and Accounting Assumptions

1.5.1.3.1 Accounting Assumptions

Changes in Capitalization Policies and Depreciation

In accordance with the Board's letter dated July 12, 2012, NPEI adopted capitalization and depreciation policies under CGAAP that were compliant with International Financial Reporting Standards on January 1, 2013. These changes were included in NPEI's 2015 Cost of Service Application (EB-2014-0096).

Capital Contributions were amortized over a period of twenty-five (25) years prior to 2015. The 2015 COS rate application was prepared using this 25-year period to amortize capital contributions. Subsequent to the approval of the 2015 COS rate application, NPEI identified that capital contributions should be amortized over the same period as the assets in which the capital contributions relate to. As a result, since 2015, the amortization period for all capital contributions was adjusted and changed from 25 years the corresponding useful life of the asset.

Transition to Modified International Financial Reporting Standards (MIFRS)

NPEI followed Canadian Generally Accepted Accounting Principles (CGAAP) in 2013 and 2014. NPEI adopted International Financial Reporting Standards effective January

1, 2015 with restatement to January 1, 2014 (transition date). NPEI adopted MIFRS for rate making purposes effective January 1, 2015 and follows the OEB's Accounting Procedures Handbook (APH).

1.5.1.3.2 Budgeting Assumptions

NPEI prepares an annual operating and capital budget that is reviewed and approved by the Finance Committee and ultimately by the Board of Directors. The operating budget is prepared annually by Senior Management on a collaborative basis with all departments of NPEI. The capital budget is prepared by the Senior VP of Asset Management and it is reviewed by the Senior VP of Finance. The capital and operating budgets are prepared before the start of each fiscal year. The current operating year is Forecasted using the actual OM&A and capital expenditures at the end of October plus an estimate for November and December. The Budget operating year is prepared and compared to the Forecasted year and the prior year Actuals. For example, the 2020 Bridge Year Budgets are compared and analyzed to the Forecasted 2019 year and the 2018 Actual year. The budgets provide a plan against which actual results may be evaluated and underpins this Application.

NPEI reviews its budgets using different methodologies to ensure its proposed budgets are reasonable before seeking its Board of Director for approval. Review methodologies employed include the Bottom Up Approach, the Top Down Approach and the Total Spend Envelope. The capital budget net of capital contributions and disposals is compared to the 2015 COS Board approved capital additions as well as the previous year's average capital additions, net of capital contributions and disposals.

The capital budget is also compared to the last Distribution System Plan to ensure the implementation of the DSP is on track.

The capital and operating budgets for the years 2015 to 2020 are included in Appendices 1-2 to 1-7 of this exhibit. The 2020 capital and operating budgets were approved by NPEI's Board of Directors on December 3, 2019.

With respect to inflation rate assumptions, the 2021 Test Year expenditures were budgeted based on the actual expected costs and not specifically based on an overall specified inflation rate, although an economic outlook was used. A suggested inflationary rate of one to two percent was given for non-salary OM&A expenditures. This range is reasonable considering the price escalator used for 2019 IRM rate applications was 2.0%. For salaries and wages, the increase was 2.0% in both 2020 Bridge Year and the 2021 Test Year, in line with the Collective Agreement. Assumptions with respect to labour rates are provided in Exhibit 4, Section 4. All incremental expenses and new initiatives above the suggested inflation must be approved by NPEI's CEO.

The budget is reviewed in a top down format to ensure that the main guiding principles are maintained and in line with NPEI's strategic plan.

Revenue Forecast

The revenue budget includes three components: energy revenue; distribution revenue and other revenue.

The energy revenue for 2021 was forecast using the weather normalized load forecast prepared by NPEI as presented in Exhibit 3. Rates for energy pass-through charges are described in Exhibit 3, section 3.1.6.

NPEI's 2021 Test Year distribution revenue was forecast using the load forecast model output provided in Exhibit 3 multiplied by the proposed rates for the 2021 Test Year. The load forecast is weather normalized and considers such factors as historical load, weather, economic data, and the impacts of Conservation and Demand Management (CDM) forecasts. The load forecast information was also used to compute the energy sales and throughput volume based on the energy pass-through charges described in Exhibit 3.

Based on the load forecast methodology, the 2021 Test Year kWh forecast is 1,286,841,405 or a 6.5% increase from the 2015 Board approved of 1,208,063,402 kWh. 2015 Actuals were 1,195,656,487 kWh or 98.97% lower than the 2015 Board approved kWh.

The forecast of customers by rate class was determined using a geometric mean analysis. In reviewing the resulting geometric means for 2004-2019, NPEI notes that the geometric means for the GS>50 kW class and the Sentinel class did not appear to be reasonable. In NPEI's view, the 2004-2019 geometric means for these two rate classes were too low to be used to forecast the customer / connection counts for 2020 and 2021.

For the GS>50 kW class, the customer counts for 2014 and 2015 were significantly impacted by the closure of a mall in Niagara Falls, as well as reclassification between the GS > 50 kW and GS < 50 kW rate classes. Therefore, for the GS>50 kW class, NPEI proposes to use the 4-year geometric mean from 2016-2019.

For the Sentinel rate class, NPEI notes that there was a significant reduction in the number of sentinel lights over the period 2009 to 2014, which appears to have stabilized in more recent years. Therefore, for the Sentinel rate class, NPEI proposes to use the 5-year geometric mean from 2015-2019.

For all of the other rate classes, NPEI proposes to use the 2004-2019 geometric means to forecast the 2020 and 2021 customer/connection counts. Table 3.1.3.11 of Exhibit 3 details the geometric means used.

The next step in the process was to review the historical customer/connection usage and to reflect this usage per customer in the forecast.

NPEI notes that the geometric means of growth rates in use per customer / connection for the period 2004 to 2019 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.

For the forecast of usage per customer/connection, the historical geometric means were applied to the 2019 usage per customer/connection to determine the 2020 forecast. The geometric mean is applied again to the 2020 values to determine the 2021 forecast.

Operations, Maintenance and Expense Forecast

The OM&A expenses for the 2020 Bridge Year and 2021 Test Year were forecast using work plans, approved pay grid progression, capital budgets, and prior year historical costs. Departmental budgets are developed using an approach which requires each functional area to identify resources, including labour, materials and outside purchases that are required to meet departmental requirements, corporate objectives, and regulatory requirements.

The following areas are forecasted as follows:

- Estimated OM&A expenses for all department budgets are built using the previous two years of actual invoices by Vendor, current year forecast and current year budget as the base;

- Significant variances in spending from prior years is explained in the budget report;

- The Finance department prepares a total labour budget by employee by department using projected wage and benefit costs. Overtime and account distribution are projected considering previous year's actual changes

- The labour required for the capital budget is reconciled to the total labour budget where the difference become OM&A labour. This only applies to the direct labour positions that are capitalized. NPEI does not capitalize any management or executive labour costs.

- Depreciation expenses are calculated using the forecast current year's additions by general ledger account and useful lives.

- Income taxes are budgeted using a 26.5% tax estimate. Future income taxes are not accounted for the annual budget.

- Net movement in regulatory accounts are budgeted for all regulatory assets and liabilities except for RSVA (Retail Settle Variance Accounts) accounts. NPEI's Sale of Energy equals its Cost of Power in the annual budget on the Statement of Income.

Key assumptions with respect to OM&A include the wages and benefits increases in accordance with the Collective Agreement between NPEI and the I.B.E.W. for the periods April 1, 2019 to March 31, 2023. Management wage increases are the same as the union negotiated increases. The allocation of labour and related costs, specifically in the operations and maintenance areas, are based on estimates of planned and unplanned maintenance activities. Estimates for unplanned maintenance and repairs are influenced to some extent by prior years' experience. External assumptions such as growth input from regions, municipalities and developers are used. Known new regulatory requirements are also incorporated into the development of the OM&A expenses forecast.

Exhibit 4 provides further details on the 2021 Test Year OM&A expenses.

<u>Capital Budget</u>

NPEI has developed a Consolidated Distribution System Plan (DSP) in accordance with Chapter 5 of the Ontario Energy Board's *Filing Requirements for Electricity Distribution Applications, Consolidated Distribution System Plan Filing Requirements* dated July 12, 2018 (Chapter 5) and the *Addendum Filing Requirements for Electricity Distribution Rate Applications – 2020 Rate Applications* dated July 15, 2019. NPEI's DSP presents NPEI's fully integrated approach to capital expenditure planning, including comprehensive documentation of its asset management process, the incorporation of results from the Asset Condition Assessment, and identification and documentation of detailed capital projects over the test year.

The DSP is expected to continue to evolve over time. NPEI's DSP is provided in Exhibit 2, Appendix 2-8.

1.5.1.4 Load Forecast Summary

NPEI has utilized the same regression analysis methodology approved by the OEB in its 2015 Cost of Service (COS) Application EB-2014-0096. The regression analysis has been updated to include actual data to the end of 2019. The updated regression analysis uses the same basic variables as the 2015 model.

The Weather Normalized Load Forecast evidence, as presented in Exhibit 3, shows that NPEI's proposed billed consumption for the 2021 Test Year is 1,286,841,405 kWh, compared to the 2015 board approved forecast of 1,208,063,402 kWh. This represents an increase of 78,778,003 kWh, or 6.5%. NPEI's total forecast billed demand, for the applicable rate classes, for the 2021 test year is 1,788,455 kW, compared to the 2015 Board approved forecast of 1,793,564 kW. This represents a decrease of 5,109 kW, or 0.28%. NPEI has projected the total customer / connection count for the 2021 test year at 71,529, compared to the 2015 Board approved forecast of 66,028 total customers / connections, which represents an increase of 5,501, or 8.3%.

With regard to the overall process of load forecasting, NPEI submits that conducting a regression analysis on historical electricity purchases to produce an equation that will predict purchases is appropriate. NPEI has the data for the amount of electricity (in kWh) purchased from the IESO and other sources for use by its customers. With a regression analysis, these purchases can be related to other monthly explanatory variables such as heating degree days and cooling degree days which occur in the same month. The results of the regression analysis produce an equation that predicts the purchases based on the explanatory variables. This prediction model is then used as the basis to forecast the total quantity of weather normalized purchases for the Bridge Year and the Test Year which is converted to forecast billed kWh by rate class.

NPEI's weather normalized load forecast is developed in a three-step process. First, a total system weather normalized purchased energy forecast is developed based on a multifactor regression model that incorporates independent variables that impact the monthly historical load pattern for NPEI. Second, the weather normalized purchased energy forecast is adjusted by a historical loss factor to produce a weather normalized billed energy forecast. Next, the forecast of billed energy by rate class is developed based on a forecast of customer numbers and historical usage patterns per customer. For the rate classes that have weather sensitive load, their forecasted billed energy is adjusted to ensure that the total billed energy forecast by rate class is equivalent to the total weather normalized billed energy forecast that has been determined from the regression model.

The forecast of customers by rate class is determined using a geometric mean analysis.

For those rate classes that use kW for the distribution volumetric billing determinant, an adjustment factor is applied to the rate class energy forecast based on the historical relationship between kW and kWh to determine a forecast for billed kW.

A detailed explanation of the load forecasting process is included in Exhibit 3, Section 3.1.3.

Table 1.5.1.4-1 below shows NPEI's proposed billed kWh (by rate class and total), billed kW and customer / connection counts for the 2015 Board Approved, and the 2021 Test Year.

Table 1.5.1.4-1: Consumption and Customer / Connection Counts

Rate Class	2015 Board Approved			2021 Test Year			Variance		
	#	kWh	kW	#	kWh	kW	#	kWh	kW
Residential	47,067	407,092,792		51,935	454,614,210		4,868	47,521,418	
GS < 50 kW	4,385	121,037,129		4,541	131,961,769		156	10,924,640	
GS > 50 kW	862	669,981,013	1,771,675	810	694,096,099	1,775,257	(52)	24,115,086	3,582
Sentinel	303	259,459	705	283	218,613	653	(20)	(40,846)	(52)
Streetlight	12,989	7,477,962	21,184	13,634	4,469,101	12,545	645	(3,008,861)	(8,639)
Unmetered Scattered Load	422	2,215,047		325	1,481,614		(97)	(733,433)	
Total	66,028	1,208,063,402	1,793,564	71,529	1,286,841,405	1,788,455	5,501	78,778,003	(5,109)

1.5.1.5 Rate Base and DSP

The Rate Base for the 2021 Test Year of $169,952,205 is an increase of $29,990,491 or 21.4% compared to the 2015 Board Approved Rate Base of $139,961,714. NPEI is not adding any assets to Rate Base as a result of a previous Price Cap IR Application.

Table 1.5.1.5.1-1 below, provides a Summary of Rate Base for the period 2014 through to the 2021 Test Year.

Table 1.5.1.5.1-1 Summary of Rate Base

Description	2015 Board Approved WAC 10.48%	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Bridge	2021 Test	Variance 2021 Test vs. 2015 Board-Approved
Gross Fixed Assets	275,337,932	277,718,817	292,411,388	306,355,532	320,005,612	336,175,261	353,457,606	370,835,204	95,497,272
Accumulated Depreciation	(133,513,838)	(133,353,402)	(139,090,311)	(145,263,088)	(151,478,242)	(158,593,945)	(166,536,274)	(174,413,867)	(40,900,030)
Gross Capital Contributions	(23,814,201)	(28,054,750)	(32,086,201)	(34,557,685)	(37,095,719)	(42,558,399)	(46,412,572)	(48,995,800)	(25,181,599)
Accumulated Amortization of Capital Contributions	8,042,651	7,463,406	8,201,844	9,026,035	9,920,039	10,922,804	12,049,613	13,261,201	5,218,550
Net Book Value	126,052,544	123,774,070	129,436,720	135,560,794	141,351,691	145,945,721	152,558,373	160,686,738	34,634,194
Average Net Book Value	123,133,488	121,994,251	126,605,395	132,498,757	138,456,243	143,648,706	149,252,047	156,622,556	33,489,067
Working Capital	160,574,664	167,717,596	182,815,582	164,694,955	155,547,319	165,517,410	171,534,673	177,728,664	17,154,000
Working Capital Allowance %	10.48%	10.48%	10.48%	10.48%	10.48%	10.48%	10.48%	7.5%	-2.98%
Working Capital Allowance	16,828,225	17,576,804	19,159,073	17,260,031	16,301,359	17,346,225	17,976,834	13,329,650	(3,498,575)
Rate Base	**139,961,713**	**139,571,055**	**145,764,468**	**149,758,789**	**154,757,602**	**160,994,930**	**167,228,881**	**169,952,205**	**29,990,492**

The variance between the 2021 Test Year and the 2015 Board approved is mainly attributed to:

- An increase in average net capital assets in service of $33,489,067 from $123,133,488 in 2015 Board Approved to $156,622,556, or 27% due to the net capital investments in the distribution system, including general plant, over the seven-year period.
- The increase in the average net capital assets in service is partially offset by a decrease in the working capital allowance. The 2021 Test Year Working Capital Allowance of $13,329,650 is $3,498,575 or 20.8% lower than the 2015 Board Approved WCA of $16,828,225. The reduction in the working capital allowance is due to:
    - ❖ A reduction in the working capital allowance percentage to 7.5% from 10.48% as approved for NPEI in the previous cost of service rate application, subsequent to NPEI filing a lead/lag study;
    - ❖ An increase in the Working Capital of $17,154,000 or 10.68%, which is comprised of Cost of Power Supply Expenses and OM&A.
    - ❖ Cost of Power Expenses increased $13,194,985 or 9.2% which is due to an increase in kWh and an increase in price.
    - ❖ Operating, Maintenance, and Administrative (OM&A) expenses, also used in the calculation, have increased $3,959,015 or 24.1%. This is more thoroughly explained in Exhibit 4.

NPEI's Board approved gross capital expenditures for 2015 were $11,698,580 less capital contributions in the amount of $827,000, less disposals in the amount of $313,581 for net capital additions of $10,557,999. For 2021, the proposed capital expenditures, net of capital contributions is $15,359,428, an increase of $4,487,848 or 41.28%. Table 1.5.1.5.1-2 below illustrates the changes by category between the 2021 Test Year and the 2015 Board Approved capital expenditures.

Table 1.5.1.5.1-2 Capital Expenditures 2021 Test Year versus 2015 Board Approved

Category	2015 Board Approved	2021 Test Year	$ Variance	% Variance
System Access	2,437,924	8,465,683	6,027,759	247.25%
System Renewal	6,742,997	6,828,182	85,185	1.26%
System Sustainment	1,028,166	1,097,810	69,644	6.77%
General Plant	1,489,492	1,550,980	61,488	4.13%
Total	11,698,580	17,942,655	6,244,075	53.37%
Capital Contributions	(827,000)	(2,583,228)	(1,756,228)	212.36%
Net Capital Expenditures	10,871,580	15,359,428	4,487,848	41.28%

The increase is primarily related to system access, which include; commercial service new connections, transfer of expansion facilities from customers, the Kalar Transformer Station additional switchgear and the Niagara South Feeder Phase I expansion related to the build of the new hospital in Niagara Falls.

As previously noted, NPEI developed a DSP in accordance with Chapter 5 of the Ontario Energy Board's Filing Requirements for Electricity Distribution Applications, Consolidated Distribution System Plan Filing Requirements dated July 12, 2018 (Chapter 5). The DSP incorporates matters pertaining to asset condition, asset management, renewable energy generation, and regional planning. The DSP has been prepared by NPEI. NPEI retained Kinetrics to advise on and assist with the Asset Condition Assessment.

1.5.1.6 OM&A Expenses

NPEI is proposing recovery through distribution rates of $20,384,010 in Operating, Maintenance, Billing and Collecting, Community relations and Administration (OM&A) costs for the 2021 Test Year, which represents an overall increase of 24.10% or $3,959,015 from the 2015 Board Approved Budget.

The proposed OM&A expenditures for the 2021 Test Year have been derived through a detailed budgeting and business planning process, which is aligned with NPEI's strategic plan and incorporates an evaluation of risk. With respect to inflation rate assumptions, the 2021 Test Year expenditures were budgeted based on the actual expected costs and not specifically based on an overall specified inflation rate, although an estimate between 1.0% and 2.0% was used where actual expected costs were unknown. An increase of 2.0% was used for compensation which is aligned with NPEI's current collective agreement with the I.B.E.W. The current collective agreement is for the period April 1, 2019 to March 31, 2023. Performance wage increases in accordance with the current collective agreement and NPEI's management salary structure was included in the 2021 Test Year compensation calculations.

A summary of the OM&A for the period 2015 through 2021 Test Year is illustrated below in Table 1.5.1.6.1-1 along with the increase over the 2015 Board Approved budget.

Table 1.5.1.6.1-1 Summary of OM&A Costs

	2015 Board Approved	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Bridge	2021 Test
Operations	4,181,150	4,310,481	4,411,325	4,732,154	4,458,287	4,985,677	4,848,724	4,798,729
Maintenance	2,439,001	2,345,782	2,203,115	2,660,236	2,589,112	2,678,573	2,567,275	2,577,832
Billing and Collecting	5,248,882	5,283,210	5,295,777	5,620,257	5,717,281	5,966,076	6,406,032	6,792,581
Community Relations	69,600	82,819	99,714	161,253	132,561	133,276	129,200	102,200
Administrative	4,486,361	4,851,149	5,136,589	5,094,537	5,123,353	5,395,203	5,672,162	6,112,668
Total	16,424,995	16,873,441	17,146,520	18,268,438	18,020,595	19,158,806	19,623,392	20,384,010

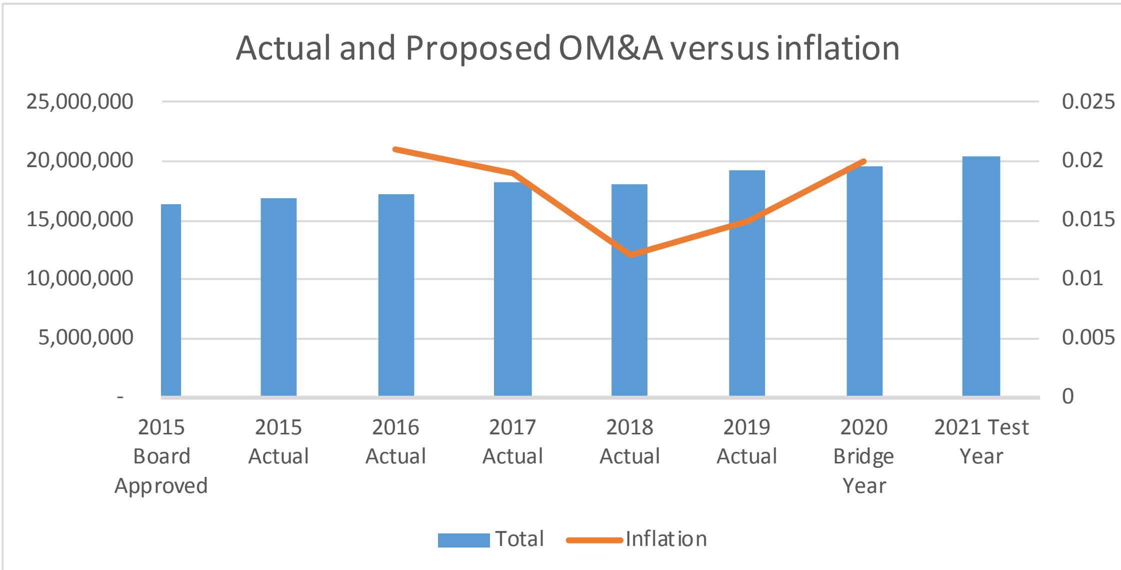
2021 Test Year vs. 2015 Board Approved	3,959,015
% Increase 2021 Test Year vs 2015 Board Approved	24.10%

The proposed OM&A budget includes several substantial incremental costs over the 2015 OM&A budget. Significant cost drivers include: meter reading due to the conversion of conventional meters to either MIST or smart meters, IT maintenance expenses including cyber security, regulatory expenses including Cost Assessment fees, future transformer station requirement expenses, postage, and the closing of the Retail Cost Variance deferral accounts. With respect to staffing level changes, the increase mainly consists of two new Customer Engagement positions whereby two former CDM employees have been transitioned due to the ending of the CDM programs, and one new Regulatory Compliance and Financial Manager. Wages and benefits have increased as a result of the annual wage increases, increases from the job evaluation process completed in 2018 and the incentive pay plan introduced in 2019. NPEI's workforce is comprised of one union and management employees. Table 1.5.1.6.2-1 below replicates Appendix 2-K of Chapter 2, summaries the employee complement, compensation and benefits for the 2015 Board Approved, 2015-2019 Actual and 2020 Bridge and 2021 Test Years. All compensation is included whether expensed or capitalized and for the 2021 Test Year, this represents a 22.47% or $3,170,562 increase over the 2015 Board Approved Budget. The number of employees is based on the computation of the number of full-time equivalent (FTE's).

Table 1.5.1.6.2-1 Employee Costs

	Last Rebasing Year (2015 OEB Approved)	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)	34	38	37	41	39	39	40	41
Non-Management (union and non-union)	92	88	85	83	83	82	86	87
Total	126	125	121	124	123	122	126	128
Total Salary and Wages including ovetime and incentive pay								
Management (including executive)	$ 3,669,803	$ 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)	$ 7,337,571	$ 7,013,699	$ 7,415,271	$ 7,162,650	$ 7,412,215	$ 7,379,676	$ 7,898,622	$ 8,033,181
Total	$ 11,007,375	$ 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)	$ 927,908	$ 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)	$ 2,171,774	$ 2,034,929	$ 2,260,580	$ 2,586,643	$ 2,432,308	$ 2,457,551	$ 2,446,459	$ 2,533,045
Total	$ 3,099,682	$ 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)	$ 4,597,712	$ 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)	$ 9,509,345	$ 9,048,628	$ 9,675,850	$ 9,749,293	$ 9,844,523	$ 9,837,227	$ 10,345,081	$ 10,566,226
Total	$ 14,107,057	$ 13,888,356	$ 15,068,104	$ 15,537,003	$ 15,674,512	$ 16,316,864	$ 16,670,854	$ 17,277,619

Chart 1.5.1.6-1 OM&A versus inflation



As can be seen by the above chart, 1.5.1.6-1, NPEI's OM&A expense were less than inflation in 2016 and 2017, above inflation in 2018 and 2019 and in-line with projected inflation for the 2020 Bridge Year and 2021 Test Year.

Detailed explanations related to OM&A costs are shown in Exhibit 4.

1.5.1.7 Cost of Capital

NPEI has not deviated from the OEB's methodology for calculating the Cost of Capital. NPEI is using the current OEB's cost of capital parameters as issued by the Board on October 31, 2019 for 2020 COS rate application filers. NPEI respects that these parameters may be updated during the Application process.

Table 1.5.1.7.1-1 Deemed Capital Structure

	(%)		($)	(%)	($)
Debt					
Long-term Debt	56.00%		$95,173,235	2.84%	$2,701,011
Short-term Debt	4.00%	(1)	$6,798,088	2.75%	$186,947
Total Debt	60.0%		$101,971,323	2.83%	$2,887,958
Equity					
Common Equity	40.00%		$67,980,882	8.52%	$5,791,971
Preferred Shares	0.00%		$ -	0.00%	$ -
Total Equity	40.0%		$67,980,882	8.52%	$5,791,971
Total	100.0%		$169,952,205	5.11%	$8,679,929

NPEI confirms that there have been no changes to its capital structure since it last rebased in 2015 (EB-2014-0096). NPEI is requesting the debt returns as issued by the OEB in its Cost of Capital parameter update issued October 31, 2019. These are subject to change during the application process.

NPEI is seeking a return on equity of 8.52% in accordance with the cost of capital parameters updates letter issued October 31, 2019. This rate is subject to change as the OEB may issue new updates during the application process.'

1.5.1.8 Cost Allocation and Rate Design

The OEB outlined its cost allocation policies in its reports of November 28, 2007 *Application of Cost Allocation for Electricity Distributors*, and March 31, 2011 *Review of Electricity Distribution Cost Allocation Policy* (EB-2010-0219).

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. The model has been loaded with 2021 Test Year costs, customer numbers and demand values for NPEI.

The data used in the updated cost allocation study is consistent with NPEI's cost data that supports the proposed 2021 revenue requirement outlined in this Application. NPEI's assets were broken out into primary and secondary distribution functions using updated breakout percentages from the 2015 Cost of Service rate application. The updated breakout percentages were derived from NPEI's GIS system. The breakout of assets, capital contributions, depreciation, accumulated depreciation, customer data and load data by primary, line transformer and secondary categories were developed from the best data available to NPEI, its engineering records, and its customer and financial information systems.

Table 1.5.1.8.1-1 below, allocated costs provides the combined allocated Board approved cost by rate class from the prior 2015 cost study along with NPEI's results from the 2021 cost allocation study.

Table 1.5.1.8-1 Allocated Costs

	2015 Board Approved Cost Allocation Study	%	2021 Proposed Cost Allocation Study	%
Residential	20,747,538	69.2%	26,201,616	69.2%
GS< 50 kW	3,173,270	10.6%	4,058,338	10.7%
GS > 50 kW	5,536,411	18.5%	7,261,574	19.2%
Sentinel	88,456	0.3%	91,894	0.2%
Streetlight	316,689	1.1%	135,878	0.4%
Unmeter Scattered Load	108,156	0.4%	91,375	0.2%
Total	29,970,520	100.0%	37,840,675	100.0%

In a letter dated June 12, 2015, the OEB reminded distributors to be mindful of material changes to load profiles and propose updates, as appropriate, in Cost of Service Applications. NPEI proposes to use the same methodology as was used in the 2015 Cost of Service Application to determine the demand data for the 2021 cost allocation model. This methodology involves applying a scaling factor to the 2004 weather normalized volumes supporting the 2004 load profiles to determine an estimate of the

2021 weather normalized load profiles. Once that is completed, the same methodology used by Hydro One on the 2004 load profiles to determine the demand data for the original cost allocation study is applied to the 2021 load profiles to determine the 2021 demand data. NPEI has provided an Excel spreadsheet named "Load profile model 2004 Hydro One data for 2021" to show how the 2021 demand data is determined.

Table 1.5.1.8-2 Proposed Revenue to Cost Ratios summarizes NPEI's proposed revenue to cost ratios for the 2021 Test Year as well as the Board's approved ranges.

Table 1.5.1.8-2 Revenue to Cost Ratios

	2015 Board Approved Cost Allocation Study	2021 Cost Allocation Study	2021 Proposed Ratios	OEB Target	
				Min	Max
Residential	91.65%	94.24%	94.24%	85.00%	115.00%
GS< 50 kW	120.00%	116.96%	116.96%	80.00%	120.00%
GS > 50 kW	120.00%	108.82%	110.71%	80.00%	120.00%
Sentinel	119.83%	126.04%	120.00%	80.00%	120.00%
Streetlight	91.65%	96.43%	96.43%	80.00%	120.00%
Unmetered Scattered Load	91.65%	217.09%	120.00%	80.00%	120.00%

The Sentinel and Unmetered Scattered Load rate classes exceed the maximum OEB target. NPEI proposes to reduce these two rate classes to equal the maximum OEB target percentage for revenue to cost. The balancing class is the GS>50 kW rate class.

It is NPEI's long-term objective to allocate its distribution costs in such a manner that ultimately achieves revenue to cost ratios approaching 100% for each rate class. The objective ensures that costs are allocated fairly to each customer class based on its respective class utilization of the distribution system.

NPEI has not deviated from the Board's 2020 Cost Allocation Model. Further details with respect to the 2020 Cost Allocation Model are provided in Exhibit 7.

Rate Design

Table 1.5.1.8-3 below, sets out NPEI's proposed 2021 electricity distribution rates based on:

i. The cost allocation methodology and proposed revenue-to-cost ratios,
ii. The proposed fixed-variable ratios; and
iii. The proposed transformer allowance.

NPEI has calculated its proposed distribution rates by rate class based on the proposed Rate Design model in Exhibit 8.

Table 1.5.1.8-3 Proposed Distribution Rates

	Proposed Monthly Service Charge	Proposed Distribution Volumetric Rate	Unit of Measure
Residential	36.15	0	kWh
GS< 50 kW	43.11	0.0157	kWh
GS > 50 kW	169.93	3.3379	kW
Sentinel	19.36	24.159	kW
Streetlight	0.73	2.9003	kW
Unmetered Scattered Load	21.14	0.0147	kWh

Table 1.5.1.8-4 below shows the proposed fixed/variable portion for each rate class.

Table 1.5.1.8-4 Proposed Fixed/Variable Portion

	Proposed 2021	
	Fixed Revenue Portion	Variable Revenue Portion
Residential	100.00%	0.00%
GS< 50 kW	53.17%	46.83%
GS > 50 kW	21.80%	78.20%
Sentinel	80.67%	19.33%
Streetlight	76.75%	23.25%
Unmetered Scattered Load	79.14%	20.86%

Based upon the customer bill impacts, and as further summarized below under Bill Impacts, NPEI is not proposing rate mitigation.

1.5.1.9 Deferral and Variance Accounts

NPEI has included in this Cost of Service (COS) Application, a request for approval for disposition of Group 1, and Group 2 Deferral and Variance Accounts (DVAs) balances as at December 31, 2019 and the forecasted interest through to December 31, 2020.

NPEI has followed the Board's guidance in the *Accounting Procedures Handbook* and *FAQ's* (APH) for recording amounts in the deferral and variance accounts. Such guidance also includes the *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative* ("EDDVAR Report")

NPEI is requesting a net disposition of $568,113 to be refunded to customers. Table 1.5.1.9-1 summarizes:

- The principle account balances in each of the deferral and variance accounts, and sub-accounts proposed for disposition; and

- Interest on the deferral and variance accounts up to December 31, 2020. Interest has been computed to December 31, 2020 to align to the proposed effective date for disposition commencing January 1, 2021, and
- Forecasted expenses for the OEB cost assessments, RCVA expenses and LRAM to December 31, 2020.

Table 1.5.1.9-1 Deferral and Variance Accounts to be Disposed

Account Description	Account Number	Principal Balance as at Dec. 31/19	Carrying Charges as at Dec. 31/19	Disposition Approved in 2020	2020 Projected Incremental Principal for Accounts to be Discontinued	2020 Projected Carrying Charges	Total Proposed for Disposition
Group 1 Accounts							
LV Variance Account	1550	1,915,647	45,612	(822,777)		24,555	1,163,038
Smart Metering Entity Charge Variance Account	1551	(30,873)	(1,396)	22,568		(210)	(9,911)
RSVA - Wholesale Market Service Charge	1580	(612,859)	(36,676)	239,201		(8,724)	(419,059)
Variance WMS – Sub-account CBR Class A	1580	-	-	-		-	-
Variance WMS – Sub-account CBR Class B	1580	(127,219)	33	27,107		(2,166)	(102,246)
RSVA - Retail Transmission Network Charge	1584	349,721	10,233	(257,865)		2,275	104,363
RSVA - Retail Transmission Connection Charge	1586	85,332	1,865	(271,103)		(3,879)	(187,786)
RSVA - Power	1588	(1,355,511)	46,337	(385,677)		(37,367)	(1,732,219)
RSVA - Global Adjustment	1589	(178)	7,892	(9,108)		(0)	(1,394)
Disposition and Recovery/Refund of Regulatory Balances (2017)	1595	(18,287)	22,911			(399)	4,225
Total Group 1		**205,773**	**96,811**	**(1,457,656)**	**-**	**(25,917)**	**(1,180,988)**
Group 2 Accounts							
Other Regulatory Assets - Sub-Account Pole Attachment Revenue Variance	1508	(346,646)	(3,146)		(331,298)	(11,168)	(692,258)
Other Regulatory Assets - Sub-Account - OEB Cost Assessment Variance	1508	233,758	9,007		52,912	5,673	301,350
Other Regulatory Assets - Sub-Account - Lead/Lag Study	1508	7,199	713			157	8,069
Other Regulatory Assets - Sub-Account - Hydro One Incremental Capital Charges	1508	4,293	368			94	4,755
Other Regulatory Assets - Sub-Account - OPEB Deferral Account	1508	(398,479)	-				(398,479)
Other Regulatory Assets - Sub-Account - LTLT Rate Mitigation	1508	4,273	92			93	4,458
Retail Cost Variance Account - Retail	1518	109,953	-		16,723		126,676
Retail Cost Variance Account - STR	1548	374,473	-		59,177		433,650
Other Accounts							
PILs and Tax Variance for 2006 and Subsequent Years- Sub-account CCA Changes	1592	(54,579)	(614)		(54,579)	(595)	(110,366)
LRAM Variance Account	1568	778,151	33,749			16,964	828,864
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential	1522	37,652	(75)				37,577
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Contra Account	1522	(37,652)	-				(37,652)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555	(24,683)	-				(24,683)
Meter Cost Deferral Account (MIST Meters)	1557	86,344	(3,161)		204,500	4,111	291,795
Accounting Changes Under CGAAP Balance + Return Component	1576	(160,882)	-				(160,882)
Total Group 2 and Other		**613,178**	**36,934**	**-**	**(52,565)**	**15,328**	**612,875**
Total for Disposition		**818,951**	**133,744**	**(1,457,656)**	**(52,565)**	**(10,588)**	**(568,113)**

NPEI is requesting the disposition of its deferral and variance accounts over a period of one-year, effective January 1, 2021.

Table 1.5.1.9-2 summarizes the billing determinants and allocators used for the rate rider computations, including the split between RPP and non-RPP customers.

Table 1.5.1.9-2 Billing Determinants

Rate Class	Total Metered kWh	Total Metered kW	# of Customers/ Connections	Distribution Revenue	Metered kWh for WMP	Metered kW for WMP	Metered kWh for non RPP	Metered kW for non RPP
Residential	454,614,210		51,935	22,529,403			16,398,472	
GS< 50 kW	131,961,769		4,541	4,420,950			23,505,891	
GS > 50 kW	697,166,267	1,775,257	810	8,041,757	3,070,169	5,800	670,267,963	1,706,460
Sentinel	218,613	653	283	81,629				
Streetlight	4,469,101	12,545	13,634	155,816			4,469,101	12,545
Unmetered Scattered Load	1,481,614		325	104,345				
Total	**1,289,911,574**	**1,788,455**	**71,529**	**35,333,899**	**3,070,169**	**5,800**	**714,641,426**	**1,719,005**

Table 1.5.1.9-3 contains a list of all Group 2 and other accounts which NPEI will continue and discontinue on a go-forward basis. NPEI is not requesting any new Deferral and Variance accounts with this Application.

Table 1.5.1.9-3 DVA Accounts to Continue/Discontinue

USoA	Account Name	Continue or Discontinue	Explanation
1508	Other Regulatory Assets - Pole Attachment Revenue	Continue	Balances will continue in this account in 2020
1508	Other Regulatory Assets - OEB Cost Assessment	Continue	Balances will continue in this account in 2020
1508	Other Regulatory Assets - Lead/Lag Study	Discontinue	NPEI is seeking recovery of the balance in this Application and no balances will accumulate in this account past 2020
1508	Other Regulatory Assets - Hydro One Incremental Capital Charges	Discontinue	NPEI is seeking recovery of the balance in this Application and no balances will accumulate in this account past 2020
1508	Other Regulatory Assets - OPEB Deferral Account	Continue	Balances will continue in this account in 2020
1508	Other Regulatory Assets - LTLT Rate Mitigation	Continue	Balances will continue in this account in 2020
1514	Retail Cost Variance Account - Retail	Discontinue	NPEI is seeking recovery of the balance in this Application and no balances will accumulate in this account past 2020
1548	Retail Cost Variance Account - STR	Discontinue	NPEI is seeking recovery of the balance in this Application and no balances will accumulate in this account past 2020
1592	PILS and Tax Variance for 2006 and Subsequent Years-Sub-account CCA changes	Discontinue	Balances will continue in this account in 2020
1568	LRAM Variance Account	Continue	Balances will continue in this account in 2020
1522	Pension & OPEB Forecast Accrual versus Cash Payment Differential Contra Account	Continue	Balances will continue in this account in 2020
1522	Pension & OPEB Forecast Accrual versus Cash Payment Differential Contra Account	Continue	Balances will continue in this account in 2020
1555	Smart Meter Capital and Recovery Offset Variance - Sub account-Stranded Meter Costs	Discontinue	NPEI is seeking recovery of the balance in this Application and no balances will accumulate in this account past 2020
1557	Meter Cost Deferral Account (MIST Meters)	Discontinue	NPEI is seeking recovery of the balance in this Application and no balances will accumulate in this account past 2020
1576	Accounting Changes Under CGAAP Balance + Return Component	Discontinue	NPEI is seeking recovery of the balance in this Application and no balances will accumulate in this account past 2020

1.5.1.10 Bill Impacts

Table 1.5.1.10-1 summarizes the customer bill impacts by customer rate class for typical consumers based upon the proposed distribution rates, load forecast, and disposition of deferral and variance accounts provided for in this Application. The bill impacts below are illustrated in the OEB's 2021_Tariff_Schedule_and_Bill_Impact_Model which is included in Appendix 8-6.

Table 1.5.1.10-1 Bill Impacts for a typical customer at NPEI

Rate Class	kWh	kW	Distribution (Fixed and Volumetric) Current 2020	Proposed 2021	$ Change	% Impact	Total Bill Current 2020	Proposed 2021	$ Change	% Impact
Residential	750	0	33.67	36.15	2.48	7.37%	121.11	122.64	1.53	1.26%
GS< 50 kW	2,000	0	69.35	74.51	5.16	7.44%	302.71	305.88	3.17	1.05%
GS > 50 kW-(non-RPP)	65,000	180	751.2	817.81	66.61	8.87%	10,701.42	10,714.48	13.06	0.12%
Sentinel -(non-RPP)	44	0.12	20.73	22.26	1.53	7.38%	21.71	22.90	1.19	5.48%
Streetlight-(non-RPP)	50	0.13	1.92	1.11	-0.81	-42.19%	9.80	9.92	0.12	1.22%
Unmetered Scattered Load	250	0	24.33	24.81	0.48	1.97%	50.68	50.72	0.04	0.08%

All bill impacts for RPP and non-RPP are shown in Table 1.2.4 and in Exhibit 8.

PROPOSED ISSUES LIST

1.5.2 Proposed Issues List

1.0 <u>Planning</u>

1.1 Capital

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

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

1.2 OM&A

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

- Customer feedback and preferences
- Productivity
- Benchmarking of costs
- Reliability and service quality
- Impact on distribution rates
- Trade-offs with capital spending
- Government-mandated obligations

- The objectives of Niagara Peninsula Energy Inc. and its customers
- The distribution system plan
- The business plan

2.0 Revenue Requirement

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

2.2 Has the Revenue Requirement been accurately determined based on these elements?

3.0 Load Forecast, Cost Allocation and Rate Design

3.1 Are the proposed load and customer forecast, loss factors, CDM adjustments and resulting billing determinants appropriate, and, to the extent applicable, are they an appropriate reflection of the energy and demand requirements of Niagara Peninsula Energy Inc.'s customers?

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

3.3 Are Niagara Peninsula Energy Inc.'s proposals for rate design appropriate?

3.4 Are the proposed Retail Transmission Service Rates appropriate?

3.5 Are the Low Voltage rates appropriate?

4.0 Accounting

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

4.2 Are Niagara Peninsula Energy Inc.'s proposal for deferral and variance accounts, including the balances in the existing accounts and their disposition, requests for discontinuation of accounts and the continuation of existing accounts, appropriate?

5.0 <u>Other</u>

5.1 Are the Specific Service Charges appropriate?

5.2 Is the proposed effective date (i.e. January 1, 2021) for 2021 rates appropriate?

Exhibit 1: Administrative Documents

Tab 6 (of 10): Materiality Threshold

TABLE 1.6-1 MATERIALITY THRESHOLD

1.6.1 Materiality threshold

NPEI's estimated distribution revenue requirement is $34,869,338. As per the OEB's chapter 2 filing requirements, dated July 12, 2018, section 2.0.8, NPEI's materiality threshold is calculated at 0.5% of distribution revenue. The table below shows a detailed calculation of the materiality threshold used in the 2021 COS rate application in the amount of $174,347.

Table 1.6-1 Materiality Threshold Calculation

Service Revenue Requirement	37,840,675
(from Revenue Deficiency Calculation)	
Less Revenue Offsets	(2,971,337)
Base Revenue Requirement	**34,869,338**
Variance Calculation 0.5% of Distribution Revenue Requirement	**$ 174,347**

Exhibit 1: Administrative Documents

Tab 7 (of 10): Customer Engagement

OVERVIEW OF CUSTOMER ENGAGEMENT

1.7 Overview of Customer Engagement

Customer Engagement is foundational to the Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach (RRFE). The RRFE states that enhanced engagement between utilities and their customers provides better alignment between utility plans and customers' needs and expectations. NPEI is expected to:

- Engage with customers in the development of its Business Plan that addresses outcomes (objectives and goals) and evaluation criteria (performance targets)
- Engage with customers on its Distribution System Plan and the associated investment and spending plans that are proposed, in order to deliver on the business plan by identifying customer preferences and needs.
- Demonstrate that its services are provided in a manner that responds to identified customer outcomes, needs and preferences.

NPEI has completed the required filing Appendix 2-AC and has included it in Appendix 1-16.

Customer engagement shapes the way NPEI conducts its business. NPEI has numerous methods of collecting and reviewing customer feedback, while constantly looking for ways to improve the services it offers and ensure value is added for its customers.

NPEI's customer engagement strategy has two main objectives:

- To improve energy literacy for customers in the following topics:
  - ➢ Electricity rates, pricing and understanding your bill
  - ➢ Rules and rights governing NPEI customer relationships
  - ➢ Safety

- The value NPEI adds to the community
- To understand the needs and priorities of its customers to ensure NPEI is meeting customer expectations with respect to reliability and customer service offerings.

Refer to Appendix 1-17 Customer Engagement Strategy for NPEI's customer engagement.

In addition, in support of the Cost of Service rate filing, NPEI undertook enhanced engagement to ensure that its Operating and Distribution System Plans meet the needs and priorities of customers.

NPEI has made some improvements in recent years in regards to Customer Engagement efforts, however, we acknowledge there is still room for improvement in this area. Going forward, NPEI will place a greater emphasis on Customer Engagement with two new resources, a Customer Engagement Manager and a Customer Engagement Key Account Coordinator who will oversee this area of the business. A Customer Engagement Plan will be created in 2020 to help shape NPEI's focus and direction with regards to Customer Engagement over the coming years.

The following sections outline how NPEI gathers and assesses customer feedback, and how it incorporates that feedback to enhance its customer service offerings to ensure value for its customers.

1.7.1 On-going Customer Engagement

On a daily basis, NPEI is in contact with customers in the following ways:

- In office visits with regards to payment arrangements, payment plans, moves, high bills, payment and balance inquiries, rate and billing information, service location requests, collection and all other general inquires.
- Telephone inquiries through the Customer Service and Billing departments.

- Email communications through the Customer Service and Billing departments.
- Online fillable forms through the NPEI Website.
- NPEI's customer portal, Customer Connect (previously My Account).
- Social media channels (Facebook and Twitter).
- Face to face meetings with customers
- Attendance at meetings with the municipalities and the Niagara Region

Every interaction that NPEI has with a customer is extremely important and considered valuable. These interactions shape the way NPEI understands customers' needs and preferences and assists in creating a plan to address these needs.

In 2019, NPEI administered over 59,000 customer transactions at its customer service counter, over the telephone and via email. Table 1.7.1-1 below illustrates the customer transactions for 2018 and 2019. This service includes opening and closing accounts, updating account information, accepting and processing payments, discussing payment plans and arrangements, providing information about bills and energy usage, and all other general account and billing inquiries. A Customer Engagement Activities report for 2018 and 2019 is included in Appendix 1-21. NPEI maintains a culture of continuous improvement and innovation and aims to provide seamless customer service by paying close attention to common customer-enquiries and working to provide information and resources that are relevant and useful for customers.

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

NPEI enables customers to interact with them according to their preferences, and strives to provide a number of contact options to ensure that every customer has the opportunity to communicate with them. As a local utility, NPEI has an open door policy for customers to visit the office to pay their bills, discuss their account or inquire about any other information. Each month, NPEI has an average of 430 customers that visit the office and engage with employees in person. This allows customers that may have limited internet or phone access, or that may prefer to speak in person, the opportunity to communicate with NPEI.

The most frequently used method of communication by NPEI customers is phoning the office. In 2019, an average of 3,647 customers contacted the office each month to speak to a Customer Service or a Billing Representative. Each conversation is documented onto the customer's account in NPEI's CIS billing system, noting the nature, discussion and outcome of the inquiry. As more customers move to online communications, the number of emails received by Customer Service and Billing has increased. In 2018, 7,960 emails were received, increasing to 10,076 in 2019. Correspondence includes opening and closing accounts, updating account information, inquiring on payment plans and payment arrangements, requesting information about bills and energy usage, and all other general account and billing inquiries. The increase in email communication highlights the trend of customers using digital tools to connect with NPEI, rather than phone calls and in-person visits.

To provide customers with self-serve options and more digital tools, NPEI offers electronic online forms including flexible options to request account access, complete connection agreements, request deposit waivers, request move in and move outs and to sign up for pre-authorized payment plans and equal payment plans. In 2018, 399 online forms were processed, and in 2019, this increased to 705 online forms processed, which is an increase of 76%.

NPEI consistently compiles data and information in regards to the customer's contact preference with NPEI, in order to work towards finding trends and patterns. NPEI staff meet quarterly to discuss questions and concerns that customers may have, and work together towards finding a solution for each. NPEI's Customer Service continues to receive high-marks on Customer Satisfaction Surveys while meeting its customer service quality indices. Ongoing communication and training is consistently provided to

Customer Service staff to ensure they are always prepared to answer any questions or concerns the customer may have.

NPEI works closely with customers who fall into the category of "vulnerable" to ensure that the needs and expectations of these customers, which can differ from other customers, are being met. NPEI offers a number of programs such as payment arrangements, an Arrears Management Payment Plan, the Affordability Fund program, the Ontario Electricity Support Program, an Equal Payment Plan and the Low-income Energy Assistance Program managed through NPEI's local Social Service Agency. NPEI documents the inquires, concerns and feedback from these customers in its CIS system in order to take the necessary steps to ensure they have every opportunity to maintain their good standing with NPEI.

As part of the 2020 Customer Engagement Plan, NPEI will offer energy management advice to all customers to help them increase their energy efficiency, and to become aware of how energy is used, where it's wasted, and how it can be used more effectively and efficiently in everyday life. Appendix 1-22 includes a list of events held between 2017 and 2019.

In addition, NPEI undertakes a targeted approach to obtain customer feedback with respect to its customer service satisfaction, including:

- Bi-annual Customer Satisfaction Surveys.
- Customer Transactional Survey through every email using Survey Monkey.
- Bi-annual Public Awareness of Safety Surveys.
- Departmental meetings to identify and discuss the most recent and common customer inquiries and/or complaints, along with finding a solution to address them.
- Touch a Truck events, Save on Energy Coupon Program events and home shows for residential customers.

These surveys and interactions, along with every-day contact with customers, helps NPEI to understand customer needs and how it can improve services to meet those needs.

1.7.1.1 Bi-Annual Customer Satisfaction Survey

On a bi-annual basis, NPEI engages a third party to survey its customers to assess customer satisfaction with the service NPEI provides and tracks the results year over year to analyze trends and determine where improvement is needed. NPEI consistently exceeds industry, national and provincial standards in many key areas. Appendix 1-18 includes the Customer Satisfaction Survey results for 2017 and 2019.

In 2019, NPEI conducted their most recent survey with a third party to gauge customer satisfaction. Table 7.1.1.1-1 below shows NPEI scored higher than the provincial and national average in all categories.

Table 7.1.1.1-1 Numbers at a Glance

	NPEI	National	Ontario
Customer Satisfaction: Initial	96%	91%	91%
Customer Satisfaction: Post	95%	91%	89%
Communication Score	82%	-	79%
Overall Satisfaction with the most recent experience	84%	78%	77%
Convenience of Services Score	82%	-	79%
Customer Experience Performance Rating (CEPr)	88%	84%	83%
Customer Centric Engagement Index (CCEI)	87%	81%	80%
Credibility & Trust Index	88%	82%	81%
NPEI's Overall Report Card	A	A	B+

While NPEI is very pleased with these results, we realize that customer expectations are constantly evolving. In order to maintain high scores, NPEI will need to take a proactive approach in improving communications and maintaining service and reliability standards.

Website enhancements including mobile optimization, increasing customer self-service options, and improving outage communications are important priorities for NPEI. Customer feedback will continue to be gathered on an ongoing basis through various surveys so that NPEI is able to respond quickly to changing customer preferences. As well, NPEI will continue to maintain and upgrade its existing infrastructure to ensure power outages are resolved quickly and customers continue to experience reliable service.

1.7.1.2 Public Safety Survey

In 2016 and 2018, NPEI engaged a third party to conduct a bi-annual survey to assess public safety awareness of the risks associated with electricity. Appendix 1-19 includes the results of the Public Awareness of Electrical Safety survey results for 2020, 2018 ad 2016. NPEI reviews the results of these surveys closely. NPEI scored an 84% Public Safety Awareness Index score in 2016. This decreased by one per cent in 2018 when NPEI scored an 83%. There were improvements in awareness in some key areas, including:

- The importance of calling for an underground locate (56.6% definitely would call in 2016 versus 62.2% definitely would call in 2018)
- Impact of touching an overhead power line (92.6% said it was very dangerous in 2016 versus 95.9% said it was very dangerous in 2018)
- Proximity to a downed power line (78% said to stay at least 10 meters away in 2016 versus 81.3% said to stay at least 10 meters away in 2018)

There were decreases in awareness in a couple of areas, including:

- Proximity to an overhead power line (20.7% were aware they needed to remain 3-6 meters away from an overhead power line in 2016 versus 18.6% in 2018)
- Danger of tampering with electrical equipment (90.7% said it was very dangerous in 2016 versus 86.7% in 2018)

- What to do if a power line falls on your vehicle when you are inside (90% said stay in your car until the hydro could be turned off in 2016 versus 86.9% in 2018)

To improve customer awareness of electrical safety, starting in 2017, NPEI in partnership with other Grid Smart City co-operative members, developed a series of six safety videos featuring Lucky the Squirrel, a squirrel who finds himself getting into trouble because he isn't aware of the hazards of electricity and what he can do to ensure he stays safe in the future. Lucky helps people learn about the importance of calling for a free underground cable locate before you dig, limits of approach for both overhead and downed power lines, what to do if a power line falls on your car, and the dangers of equipment inside pad-mount transformers and on a power line. Forty-five utilities and the ESA partnered on the development of the videos, helping to keep costs low and amplifying the messages across Ontario. The videos are used in NPEI's electrical safety school program, which is delivered at no charge to Grade 5 and 6 students each year in NPEI's service territory.

In 2018, it was a priority for NPEI to improve safety communication efforts. NPEI as a member of the Grid Smart City co-operative, supplemented the standard safety questions with extra questions to discover where the public finds information related to electrical safety and how many actively speak to their children about electrical safety. This revealed that 20.2% of survey respondents had school-aged children and of that 20.2%, only 57.1% claimed to have had conversations with their children about electrical safety.

The inclusion of the supplementary questions supplied by the Grid Smart City Communications Committee revealed that 63% of respondents get their electrical safety information online, either from searches (29.9%) or from their local electricity distributor website (33.1%). NPEI used this information to enhance its power outage pages to include links to safety information and the videos.

1.7.1.3 Customer Transactional Surveys

As a way to evaluate and ensure quality customer service, NPEI attaches a short, customer satisfaction survey to all email correspondences it has with customers. Appendix 1-20 includes the results of the Customer Service transactional survey results. This survey is a way to collect feedback about the service a customer recently received and to provide them with an opportunity to add additional comments or suggestions. The survey helps to identify and track trends in customer needs and preferences, and once analyzed, NPEI's Customer Service department staff review the replies in order to take any action that may be required. Certain comments or concerns are followed up on with the customers if they have chosen to identify themselves or ask to be contacted. NPEI regularly receives positive feedback from this survey. This includes:

- Praising specific Customer Service Representatives or Linemen for their work.
- The effectiveness of informative communications sent out to customers.
- General praise for NPEI as a company and the work being done by staff as a whole.

Some of the main concerns NPEI heard about from customers through this survey were:

- The NPEI *My Account* portal is not user-friendly and customers do not enjoy using it with its current look and feel.
- The need to make it easier to transition from the e-bill email notification to the website and to view the bill online.
- The need for more education for customers in regards to how the bill is calculated and billed, and how electricity is transmitted.
- The cost of electricity.
- NPEI's website is outdated, pathetic, and not user-friendly

From these concerns, NPEI has undertaken the following to improve Customer Service in these areas:

- NPEI launched a new online customer portal on February 10, 2020 called *Customer Connect*, as an upgrade to the current *My Account* portal. This will simplify the customer experience of locating information online, such as current and past bills, electricity usage, service requests and more.
- In 2019 NPEI developed a new informational handout to educate customers on the bill breakdown and how prices are determined. Generation, transmission and local distribution are outlined to give customers a better understanding of these costs and who is responsible for each. It also defines the portion of each bill that NPEI retains, and the amount that is distributed to different companies and government agencies.
- NPEI's Communications Coordinator receives an email notification when a Google review is posted. This staff member follows up with the Customer Service department if any follow-up is required.
- NPEI included an amount in the 2020 capital budget to redesign its website
- As party of the 2020 Customer Engagement Plan, NPEI will explore options to create a series of informational and instructional videos to be featured on the NPEI website, social media, and YouTube. The videos will cover topics such as safety, conservation, how to view/pay your bill online, and more.

1.7.1.4 Social Media and Website

NPEI embraces social media as a communication tool and a way to engage with customers. NPEI started their social media channels, Facebook and Twitter, in 2011 and their following continues to grow. At the beginning of 2020, NPEI had 3,000 Facebook, and 2,869 Twitter users. An example of NPEI's social media post is included in Appendix 1-23. Appendix 1-24 is NPEI's Social Media Report for December 2019.

As customer behaviors evolve, more customers are using social media as a way to communicate with NPEI and to inquire about power outages and account information. During a power outage, NPEI is especially active on social media, providing customers with frequent updates about the outage, cause and estimated restoration time.

NPEI also uses their social media as a platform to promote programs, publish media releases and communicate key messages. NPEI circulates photos of work being done in the community, and engages with customers who respond and comment on these photos or stories. NPEI often receives compliments and positive feedback over social media, especially acknowledging linemen during stressful work conditions, and for exceptional experiences with customer service.

NPEI uses their website as another channel to provide customers with information and news about the company, industry and electricity landscape. The website hosts all of NPEI's online forms which customers can submit to request services such as move-ins and move-outs, account access permissions, pre-authorized payment requests and more. NPEI provides customers with access to their outage map through their website, so that customers can track and acquire information in regards to power outages. The site contains information about customer service assistance, online resources and contact information for NPEI. The NPEI website is reviewed weekly to ensure that all information is relevant and up to date.

Following an internal committee review of the NPEI website, it was determined that NPEI would undergo a project to enhance and update their main website in 2020. The project is aiming to make navigation more intuitive and to have information more easily accessible.

1.7.1.5 Empowering Customers

1.7.1.5.1 Updated Nuvoxx Phone System

During large outages, there were times when NPEI had many customers phoning in to report the outage at the same time. This issue was with NPEI's phone service, as it could only handle 24 simultaneous calls before customers would receive a busy signal or get disconnected. As part of NPEI's efforts to increase customer service satisfaction, NPEI worked with its after-hours answering service provider and a third party named Nuvoxx to increase the number of ports/calls that could be received at the same time, without customers receiving a busy signal or getting disconnecting. These efforts have ensured that customers can seamlessly call in during and after business-hours to report an outage, thus improving customer satisfaction and outage-reporting. This new system also allows the Communications Department to update the messaging during an outage on the fly. Since the inception of the NuVoxx system NPEI has received zero complaints regarding a busy signal.

1.7.1.5.2 Contact Manager

In the fourth quarter of 2020, NPEI will launch its new *Contact Manager module*. *Contact Manager* is a module inside NPEI's Customer Information System in which customer contact and billing information is stored. Within *Contact Manager,* customer information and preferences can be updated and personalized to suit each specific customer. Customers can request who they would like to be contacted, and by which methods of communication they would like to receive that information. For example, customers may request text message notifications to alert them of power outages in their area, but may request email notifications regarding bills and payments. Other communication methods include email, telephone, mobile phone, text message, social media message and more. For accounts with more than one individual listed, customers may request what information they would like each individual to receive, and by which method they would like to be contacted. *Contact Manager* will help NPEI accommodate customer preferences and needs by choosing the method to most effectively communicate with them.

The full extent and capability of *Contact Manager* includes:

- Automating workflow efficiency for new services, letter generation, billing and collections
- Defining Primary and Secondary Contacts
- Defining additional contacts
- Setting preferred method of communication for each contact
- Setting notification preferences for each type of communication

1.7.1.5.3 My Account Portal updated to Customer Connect

<u>My Account</u>

In 2011, NPEI launched an interactive online-portal for customers called *My Account*. At the time, customers were looking for a hands on approach to manage their electricity accounts and consumption themselves. *My Account* provided customers with online resources to manage their electricity consumption and view usage, view and print current and past bills and view current bill amounts. The portal was launched on the precipice of a postal strike in June 2011 and provided customers with an alternative means to access their account and billing information.

In the years since *My Account* was launched, over 21,000 customers have signed up for the online portal.

NPEI has heard from customers over the past few years that *My Account* had become very outdated and customers wanted an updated, refreshed version of *My Account*. In the Customer Service Transactional Survey, 77 out of the 289 comments received since 2017 were regarding the old *My Account* service and expressed a desire for an update. To accommodate these requests and to ensure NPEI was keeping up with customer expectations and needs, NPEI launched *Customer Connect* in 2020.

<u>Customer Connect</u>

Customer Connect is a new and updated online portal that gives customers more ease of use. Improved self-serve functions allow customers to update and manage their billing and account information without the need to contact or visit the NPEI office. With a new user-friendly interface, customers will be able to keep track of their bills and manage their consumption and usage in a more straightforward and less complicated manner. Customer Connect puts customer security and privacy as a top priority, with end-to-end encryption as well as user authentication and time-outs to ensure that only authorized users obtain access, which means both customer and utility information remain protected and secure.

Features of *Customer Connect* that build upon the existing features of *My Account* include:

- New Service Connection Set Up
- Move/Transfer Premises
- Pay Now
- Request a Service Call
- Display Billed Demand and kWh Usage
- Enhanced display of bill history and transaction history

More features and tools will be added to Customer Connect in the future that will help NPEI stay up to date with customer priorities and expectations. This will include the ability for customers to select their preferred notification methods, which allows customers to be contacted in the way that works best for them. As well, improved self-service tools for large industrial customers will be added. NPEI plans to monitor feedback to continuously improve *Customer Connect* to maintain a high level of customer satisfaction with the online portal.

1.7.1.5.4 Outreach Activities

Residential Customers

As the local hydro provider, NPEI places great importance on being actively involved in the various communities they service. Appendix 1-22 is a listing of events held by NPEI between 2017 and 2019. Participating at home shows, Touch-a-Truck events, and other community activities is a key customer engagement tool in which NPEI is able to meet and engage with customers that may not have had the opportunity to make contact with the office. During these events, staff are able to communicate with customers about things they may not have previously heard about, such as new services, billing changes, low income support programs, safety awareness and energy-efficiency best practices. The events also provide an opportunity for NPEI to obtain and respond to customer feedback, and report back to the office with ideas for customer service and communication improvements.

Between 2015 and 2019, leveraging the Save on Energy Coupon Program, NPEI actively participated in Retailer Events at various stores across its service territory. At each of these events, NPEI staff were on site to explain the benefits of converting to more energy-efficient products and have conversations in regards to NPEI's services. Customers were pleased to see NPEI staff on location and some came prepared to discuss issues with their accounts or with questions regarding their energy-usage. For each of these events, NPEI:

- Had prominent signage at each participating location for the duration of the events including coupon displays near eligible products, posters in-store, and signs indicating where NPEI's booth was set up within the store.
- Advertised in local newspapers, detailing the exact locations and times for NPEI staff to be present at each store, as well as highlighting some of the promotions and deals that were being offered in-store.
- Posted messages through social media encouraging customers to attend the events in-store to speak with NPEI staff and to upgrade products in their home to be more energy-efficient.
- Distributed informational and promotional material centered around the NPEI key message and brand.

NPEI participates annually in Touch-a-Truck events in Niagara Falls, Lincoln and West Lincoln. The events are an opportunity for customers and children to interact with equipment that NPEI uses on a daily basis such as bucket trucks, auger trucks, climbing gear and safety gear. The focus of the event is mainly electrical safety for lineman working out in the field, however, it also focuses on safety in the home and out in the community for children and families. NPEI staff are on hand, including both linemen and office workers, to answer any questions customers may have regarding the equipment, billing or other services. For each of these events, NPEI:

- Posts messages on the NPEI website and social media channels encouraging customers to come out and interact with them.
- Sets up interactive displays to showcase the work linemen do on a daily basis.
- Encourages electrical safety, through demonstrations and informational and promotional material.

From 2015 to 2019, NPEI also attended a variety of home shows in its service territory as a way to interact with the community. NPEI also plans to attend more of these home shows in 2020 and 2021. Here, NPEI engaged customers in meaningful conversations that help to gauge public sentiment towards current services and programs. NPEI staff is on-site to answer questions and listen to concerns raised by customers. At these events, NPEI does some or all of the following:

- Advertise in local newspapers using funds provided from I.E.S.O. detailing the exact locations and times for NPEI to be present at the events.
- Posts messages through social media encouraging customers to attend the events and come out prepared to ask questions or talk about concerns that they may have.
- Distributes information through promotional and informational material centered around the NPEI brand and key messages.
- Have staff on-site to meet with customers and discuss questions and concerns that customers may have.
- Collect contact information from customers to help keep records and account information up to date.
- As part of the 2020 Customer Engagement Plan, NPEI will demonstrate and educate Customers on how to use Customer Connect at these events

Prior to any event that NPEI participates in, a small group session is held internally to discuss some of the current programs and services being offered, as well as some of the concerns that customers may be having at the time. This helps to ensure that staff at the event are well prepared to answer questions and address concerns that customers may have. As well, a debriefing session is held after the event to bring forth any new questions or concerns that were raised and to discuss possible solutions. This helps to confirm that customer needs and requests are being met as best as possible.

NPEI holds Public Information Meetings for residential customers to discuss upcoming capital projects that are occurring in their neighborhood. Attendance is recorded with the customer's name, address and phone number. These meetings are a way for NPEI to discuss past work that has been completed in the area and address how the process impacted customers. Any concerns or disruptions that customers had in the past will help NPEI address how they will be corrected moving forward. Future plans and projects are also discussed to ensure that customers are aware of all the possible hazards, obstacles and restrictions that may be in place while the work is being completed by NPEI. Following these meetings, NPEI staff discuss all customer concerns, and ensure that there is a minimal amount of impact on customers. NPEI has three Public Information Meetings scheduled for 2020 in order to keep customers informed of planned Capital Projects and to maintain a high level of communication with customers.

Small Business Customers

From 2015 to 2019, throughout the duration of the Save on Energy programs, NPEI communicated with small businesses about programs and incentives offered by the utility to help customers make informed decisions on how to best reduce their bills. Through phone calls, emails and in-person assessments, NPEI helped many small businesses reach their energy-saving potential through the Small Business Lighting Program and the Business Refrigeration Incentive Program. Although both of these programs ended in April of 2019, NPEI remains committed to helping Small Business customers improve their energy efficiency and manage their bills.

NPEI staff attend small business networking events monthly. These events provide a great opportunity to communicate with owners and staff of small businesses within NPEI's service territory, while staying in touch with current issues and challenges facing this community. Following these events, NPEI staff follow-up with new and/or existing contacts to create a dialog and inform customers of how NPEI can assist them in understanding and managing their energy bills.

Commercial Customers

Leveraging the Save on Energy conservation programs, NPEI made an effort to contact every large commercial customer to educate them on available incentives and energy saving opportunities. Staff regularly visited customers on site to provide facility walk-throughs and become more familiar with customer business processes and energy usage. NPEI offers additional support for incentive applications, energy management expertise, and billing support. Through this personalized customer engagement, NPEI was able to build strong relationships that have continued after the discontinuation of the Save on Energy Programs. NPEI's billing and conservation departments are regularly in contact with large commercial users to answer inquires and provide support for any needs they may have. NPEI is largely involved in planning for new-builds and expansions of large commercial customers to assist in energy-management and to identify energy-saving opportunities.

Each year, NPEI holds two customer-engagement meetings with its large commercial customers to educate them about current opportunities and to support them with any billing inquiries. During these meetings, NPEI staff reviews the Class A Program, provides education on how industrial and commercial customers are billed, explains how usage and demand can be monitored and how peak periods are defined and tracked. These meetings assist in building relationships with these large commercial customers and ensure that their needs and expectations are met and exceeded by NPEI.

Public Utility Groups

NPEI meets monthly with Public Utility groups in the area to exchange information and review processes and up-coming plans. New and ongoing projects are discussed at these meetings as a way to keep everyone informed of plans.

ENHANCED CUSTOMER ENGAGEMENT

1.7.2 Enhanced Customer Engagement

In preparation for filling its Cost of Service Application and in keeping with the requirements of the RRFE, NPEI engaged Innovative Research Group to support enhanced customer engagement outreach to assess customer needs, wants, and preferences with respect to NPEI's Distribution System Plan. NPEI and Innovative Research Group worked collaboratively to develop a workbook that explains the content of NPEI's proposed plan, the cost pressures that drive NPEI's decision making process, and the choices customers have that can help inform NPEI's plans.

Between June and December of 2019, Niagara Peninsula Energy gathered feedback from more than 3,000 Residential, Small business and Commercial customers through its customer engagement efforts. In context, Niagara Peninsula Energy, through Innovative, engaged with nearly 6% of its entire customer base.

Throughout this customer engagement process, a concerted effort was made to ensure that all customers – regardless of where they live or operate, or how much electricity they use - had an equal opportunity to participate, whether through voluntary or random sampling. In order to facilitate the collection of this robust feedback, Innovative and NPEI developed a two-phased approach which was both iterative and responsive at each stage of feedback.

Phase 1 was conducted at the beginning of NPEI's planning cycle in order to ensure that customer's needs and preferences regarding the utility's overall goals and focus for the 2021-2025 period were taken into consideration when creating the Distribution System Plan. An initial round of four focus groups was conducted amongst residential and small business customers in both Niagara Falls and Lincoln to obtain initial customer insights. Appendix 1-28 includes the handouts provided at the Residential or Small Business Focus Group meetings. The results of these focus groups helped inform the questions that were asked in a subsequent series of telephone and online surveys. Through these efforts it was recognized that NPEI was currently meeting customer needs, and a broad list of outcomes and goals that NPEI should be focusing on were identified, and prioritized.

The top three priorities for both residential and small business customers were:

- Ensuring reliable electrical service
- Delivering electricity at reasonable distribution rates
- Finding internal efficiencies and ways to find cost savings

Other important outcomes/goals identified were:

- Providing quality customer service and enhanced communications
- Proactively replacing aging infrastructure that is beyond its useful life
- Upgrading the electrical system to better respond to and withstand the impact of adverse weather and climate change
- Providing tools and services that allow customers to better manage their electricity usage

Using the input from the Phase I customer engagement, NPEI's Engineering department developed a draft plan that included an estimated baseline cost and in Phase 2, identified a number of investment areas where pacing could be accelerated, or slowed down, in order to align with customer needs and expectations. In order to obtain this feedback, an online "workbook" was designed to both educate customers on NPEI's role in the electricity system and its draft business plans, as well as to gather feedback on trade-offs between seven specific investments. Tailored workbooks for Residential, Small Business, and GS>50 kW were deployed to all customers with an email address on file, as well as promoted through a generic link on NPEI's website. Appendix 1-25 includes NPEI's Customer Engagement Final Report. Appendix 7.0 of the Customer Engagement Final Report is the Residential Workbook layout. The Small Business

Workbook layout can be found in Appendix 1-26 and the Large Commercial Workbook layout can be found in Appendix 1-27.

The online workbook was supported by a comprehensive communications strategy that included:

- A review of all emails on file for GS>50 kW and GS<50 kW customers. Customers who did not have an email contact on file with NPEI were called by an NPEI employee with an invitation to provide their email address for the purpose of being emailed an online workbook. A total of 981 customers were phoned, and 400 of these customers volunteered an email address.

- A contest for customers who completed the survey to be entered into a draw to win a $500 cash prize.

- A specific webpage (npei.ca/feedback) was created to inform customers about the survey and provide a link to complete it, as well as posting a web banner on NPEI's landing page advertising the survey.

- An email blast was sent to 11,962 residential customers, 1,446 small business customers, and 447 GS>50kW commercial customers.

- An email blast was sent through the Niagara Falls Chamber of Commerce, and Lincoln Chamber of Commerce.

- A social media advertising campaign that achieved 68,165 impressions and 1,592 clicks.

- Hard copies of the survey were made available at the NPEI office for any customer who did not have access to a computer or the internet.

- Employee communications via email, corporate intranet, and in person information sessions for NPEI staff were held to become familiar with the survey content, so they could promote uptake amongst customers.

In total 1,488 residential, 65 small business, and 32 large commercial customers who represent 74 unique accounts, completed the workbook.

In the online workbook, customers were asked to rate how strongly they agreed with the statement, “The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities”. Customers who strongly agreed with this statement were classified as “Vulnerable Customers” for the purposes of analyzing feedback received in the workbook. Seeing as rate impacts will have the largest impact on this customer type, NPEI planners placed emphasis on considering their specific preferences when making decisions to adjust specific capital spending programs.

1.7.2.1 Responding to Customer Preferences

Overall, NPEI’s customers were supportive of its 2021-2025 draft plan as it was presented during the customer engagement process. In each of the three workbooks (Residential, Small Business and GS > 50 kW), the majority of customers surveyed indicated a preference for NPEI to either maintain the proposed rate increase to deliver a program that focuses on the priorities of its draft plan, or to improve service even if that means an increase that exceeds what is proposed in the draft plan.

In each case however, the customer support for maintaining the proposed level of rate increase included in the draft plan was greater than the customer support for improving service even if that means an increase that exceeds what is proposed in the draft plan. Further, among Vulnerable Residential customers, a minority (29%) indicated that NPEI should keep increases below what is proposed in the draft plan even if that means reductions in service, compared to 11% of Residential customers overall.

In determining whether to adjust the overall level of spending proposed in its draft plan, NPEI has considered the following factors:

- Balancing customer preferences in general against the preferences expressed by the more vulnerable Residential customers.
- The resulting level of bill impacts to all customer classes.
- Internal resource constraints: whether or not an increase in the overall level of proposed capital projects or programs may require additional engineering or operations resources beyond NPEI's current staffing levels.
- Financial leverage: whether or not an increase in the overall level of proposed capital projects or programs may require NPEI to incur additional debt.

Based on the above considerations, NPEI has decided to maintain the overall proposed level of capital spending consistent with what was included in the draft plan. In response to customer preferences on pacing of capital investments, NPEI has made adjustments to several specific capital programs, as detailed below.
In addition, if capital projects or programs that are planned during the 2021-2025 period need to be deferred, NPEI will incorporate customer preferences when selecting alternative projects to prioritize.

<u>Overhead Pole Replacement</u>

Among Residential customers, a plurality (47%) indicated a preference for an accelerated pace, while among Vulnerable Residential customers, a plurality (43%) indicated a preference for a slower pace than what was proposed in the draft plan. Among Small Business Customers, a majority (56%) indicated a preference for an accelerated pace.

Of the GS>50 kW respondents, 15 of 32 indicated a preference for the pace that was included in the draft plan.

In considering the overall customer preferences from each rate class, as well as the specific preferences of the more vulnerable Residential customers, NPEI has decided to maintain its proposed plan for Overhead Pole Replacement.

Overhead Transformer Replacement

Among Residential customers, a plurality (47%) indicated a preference for an accelerated pace, while among Vulnerable Residential customers, a plurality (38%) indicated a preference for a slower pace than what was proposed in the draft plan. Among Small Business Customers, a majority (53%) indicated a preference for an accelerated pace.

Of the GS>50 kW respondents, 14 of 32 indicated a preference for an accelerated pace and 12 of 32 indicated a preference for what was included in the draft plan. Although there is an apparent overall preference for an accelerated pace, Vulnerable Residential customers prefer a slower pace. In addition, the majority of Residential and GS>50 kW customers preferred either the draft plan or slower pace. Therefore, NPEI has decided to maintain its proposed plan for Overhead Transformer Replacement.

Converting Outdated Underground Kiosk Transformers

Among Residential customers, a majority (56%) indicated a preference for the pace that was included in the draft plan, while among Vulnerable Residential customers, a strong majority (73%) indicated a preference for either a reduced pace, or an even slower pace.

Among Small Business Customers, a majority (60%) indicated a preference for the pace that was included in the draft plan. Of the GS>50 kW respondents, 21 of 32 indicated a preference for the pace that was included in the draft plan.

Although there is an apparent overall preference for the pace that was included in the draft plan, 73% of Vulnerable Residential exhibited a preference for a reduced pace or an even slower pace. In response, NPEI has reduced the proposed Conversion of Outdated Underground Kiosk Transformers Program from replacing 11 units per year to 8 units per year, resulting in a reduction of $242,000 to this program.

Underground Cable Replacement

Among Residential customers, a majority (65%) indicated a preference for an accelerated pace, or an even further accelerated pace, while among Vulnerable Residential customers, a majority (58%) indicated a preference for an accelerated pace, or an even further accelerated pace.

Among Small Business Customers, a majority (68%) indicated a preference for an accelerated pace, or an even further accelerated pace.

Of the GS>50 kW respondents, 16 of 32 indicated a preference for the pace that was included in the draft plan, 14 of 32 indicated a preference for an accelerated pace and 2 of 32 preferred a further accelerated pace.

In response to the overall preference amongst all customer types for an accelerated pace or an even further accelerated pace, NPEI has increased the level of its Underground Cable Replacement Program. In order to maintain the overall level of proposed capital spending, NPEI has increased the proposed Underground Cable Replacement budget by $242,000, which corresponds to the reduction made to the Conversion of Outdated Underground Kiosk Transformers Program. This proposed increase will allow NPEI to proactively replace approximately 0.3 km of additional underground cable annually.

<u>Subdivision Underground Rehabilitation</u>

Among Residential customers, a plurality (45%) indicated a preference for the pace that was included in the draft plan, while among Vulnerable Residential customers, a plurality (45%) indicated a preference for a slower pace.

Among Small Business Customers, a majority (52%) indicated a preference for the pace that was included in the draft plan.

Of the GS>50 kW respondents, 14 of 32 indicated a preference for a slower pace.
In considering the overall customer preferences from each rate class, as well as the more vulnerable Residential customers, NPEI has decided to maintain its proposed plan for Subdivision Underground Rehabilitation.

<u>Overhead Rebuilds</u>

Among Residential customers, a narrow majority (50%) indicated a preference for the pace that was included in the draft plan, while among Vulnerable Residential customers, a plurality (39%) indicated a preference for the pace that was included in the draft plan.

Among Small Business Customers, a plurality (45%) indicated a preference for the pace that was included in the draft plan.
Of the GS>50 kW respondents, 19 of 32 indicated a preference for the pace that was included in the draft plan.

Due to the agreement of overall customer preferences for the pace that was included in the draft plan, NPEI has decided to maintain its proposed plan for Overhead Rebuilds.

Grid Modernization

Among Residential customers, a plurality (44%) indicated a preference for the pace that was included in the draft plan, and among Vulnerable Residential customers, a plurality (38%) also indicated a preference for the pace that was included in the draft plan.

Among Small Business Customers, an equal number (41%) indicated a preference for the pace that was included in the draft plan as those who indicated a preference for an accelerated pace.

Of the GS>50 kW respondents, 14 of 32 indicated a preference for the pace that was included in the draft plan and 12 of 32 indicated a preference for an accelerated pace. Due to the agreement of overall customer preferences for the pace that was included in the draft plan, NPEI has decided to maintain its proposed plan for Grid Modernization.

Commercial GS>50 kW Rate Design

Currently, distribution rates for the GS>50 kW rate class are split on a 15% fixed and 85% variable rate basis. In order to improve cost certainty, some customers have expressed a desire to move to a more fixed distribution rate. In its current draft plan, NPEI is proposing a fixed portion of the distribution charge of 21.5% and a variable charge of 78.5%. Not only does this create more cost certainty for customers, but it also provides revenue certainty for NPEI to operate and maintain the distribution system.

For customers who have predictable electricity usage habits, this change likely wouldn't have much of an impact, while creating more certainty for those whose electricity usage fluctuates more regularly.

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
- Results of the survey for this question were as follows:
- Status Quo – 11 in favour
- Included in Draft Plan – 20 in favour
- Higher Fixed Distribution Charge – 1 in favour

Considering these results, NPEI is proposing a fixed/variable split of 21.5% fixed and 78.5% variable as calculated in the 2021 Cost Allocation model using the Minimum System with PLCC Adjustment similar to the 2015 Cost of Service rate application.

RESPONSES TO LETTERS OF COMMENT FILED WITH THE OEB

1.7.3 Letters of comment filed with the OEB

NPEI will file all responses to letters of comment filed with the OEB during the cost of service rate application process.

Exhibit 1: Administrative Documents

Tab 8 (of 10): Performance Measurement

PERFORMANCE MEASUREMENT OVERVIEW

1.8.1 Performance measurement overview

NPEI monitors its performance using internal and external benchmarking. Quarterly Operations, Engineering, Finance, Customer Service, Human Resources and Personnel, IT, Billing, Communications and Public Relations department reports are prepared by each Department Head. These reports are reviewed by the CEO and included in the package sent to NPEI's Board of Directors. Also, on a monthly basis the Senior Vice President of Finance prepares the internal financial statements which include the Balance Sheet and Income Statement. The monthly financial statements are emailed to the Finance Committee along with any explanations of material variances to the current year budget and the prior year. Comparisons are on a monthly and year-to-date basis. Trends are analyzed and acted on.

As part of NPEI's Business Planning, corporate goals are set based on the results of external and internal benchmarking as well as any changes in legislation.

SCORECARDS

1.8.2 Scorecards

NPEI's Scorecard for 2018 was published on its website in September 2019. The 2019 Scorecard will not be published or final at the time of filing this Application, therefore, to the best of NPEI's ability it has provided a forecast for 2019.

NPEI's 2018 Scorecard and Management Discussion and Analysis is shown in Appendix 1-29. NPEI has projected its results for 2019. Appendix 1-30 illustrates the Actual numbers for the years 2015 to 2018. At the time of filing this rate application the PEG report had not been issued for 2019.

DISCUSSION OF PERFORMANCE BY MEASURE AND IMPROVEMENT PLANS

1.8.3 Discussion of performance by measure and improvement plans

Customer Focus

Service Quality

New Residential/Small Business Services Connected on Time

NPEI has always exceeded the standard for connecting new services. In 2018, NPEI connected 93.33% of 465 eligible low-volume residential and small business customers (those utilizing connections under 750 volts) to its system within the five-day timeline prescribed by the OEB. In 2019, NPEI connected 93.57% of its low-volume residential and small business customers to its system within the five-day timeline.

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 898 appointments with its customers in 2018 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 98.89% of these appointments on time in 2018, which is comparable to 2017 (98.34%) and exceeds the industry target of 90%.

NPEI achieved 99.50% of these appointments on time in 2019.

<u>Telephone Calls Answered On Time</u>

In 2018, NPEI's Customer Service Representatives received over 42,500 calls from its customers, which equals 171 calls per working day. A Customer Service representative answered a call in 30 seconds or less in 85.87% of these calls, which is comparable to 2017 (87.99%) and exceeds the OEB-mandated 65% target for timely call response.

In 2019, 84.67% of all calls were answered on time.

Customer Satisfaction

<u>First Contact Resolution</u>

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 91% in 2018, which is comparable to 2017 (2017 = 92%). NPEI will continue to implement and track First Contact Resolution.

In 2019, NPEI streamlined processes and improved its First Contact Resolution to achieve 96.76%.

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 2018, NPEI issued more than 664,000 bills and achieved a billing accuracy of 99.06%. This represents a slight decline over the prior year (2017 = 99.46%) 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.

In 2019, NPEI's billing accuracy was 98.79%.

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 scorecard, 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%).

NPEI's customer satisfaction survey results report is found at Appendix 1-18.

NPEI's next customer satisfaction survey is scheduled to be completed in 2021, therefore the results on the 2019 Scorecard will be 95%.

Operational Effectiveness

Safety

Level of Public Awareness

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%.

NPEI conducted its next electrical safety survey in the first quarter of 2020 for the 2019 Scorecard. NPEI participated in the Public Awareness of Electrical Safety Survey in the first quarter of 2020, along with 11 other members of Grid Smart City. The Grid Smart City's Overall Public Safety Awareness Index Score was 82%. Appendix 1-19 includes the 2020 Public Awareness of Electrical Safety Survey.

- 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

NPEI reported no serious electrical incidents involving its equipment and the general public. The result was a total of zero (0) incidents with a rate of 0.000 incidents per 1,000 km of line for 2018. In 2019, there were two serious electrical public incidents.

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/Total 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 2018 average number of hours that power to a customer was interrupted is 1.98 (2017 = 1.37). NPEI's target for 2018 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 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. For example, in 2012 and 2013 the Murray TS 3M30 feeder was a significant contributor to both SAIDI and SAIFI. A capital project was executed to correct this deficiency by reducing feeder exposure and introducing redundant supply to the area. Another capital project was executed in 2014 which was selected for execution based on cost/risk-differential analysis in order to mitigate reliability issues on the Vineland DS 4501F1 feeder. This circuit was a significant contributor to SAIDI and SAIFI in 2014. Implementation of this project reduced feeder exposure by an additional point of supply to the area, created more system loops and rebuilt plant that was at end of life.

NPEI will continue to trend feeder performance and evaluate technical alternatives to correct deficiencies. During 2017-2018, NPEI competed a multi-year project which provides a tie point to a second source of supply to the Jordan area from the NWTS M5. This area was previously serviced by a radial supply from the Vineland 4501F1 feeder which has experienced degradation in SAIDI and SAIFI due to lack of redundancy. The total cost of the multi-year implementation was $1.4M.

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.

NPEI's SAIDI was 2.03 in 2019 which was below the target of 2.58.

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/Total 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 2018 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 Cost-of-Service Rate Application), excluding the impact of Major Events. NPEI's SAIFI result for 2018 is 1.65, which represents a slight increase over 2017 (2017 = 1.55).

A significant factor contributing to the increase in the average number of interruptions in 2018 are outages due to two high wind events that impacted the Niagara region on April 4, 2018 (affecting 11,052 of NPEI's customers) and on May 4, 2018 (affecting 9,767 of NPEI's customers). On both of these dates, Environment Canada issued a warning about strong winds, which gusted up to 100 km/h in the area. Excluding the impact of the outages due to high winds on April 4, 2018 and May 4, 2018 would result in an Average Number of Times that Power to a Customer is Interrupted for 2018 of 1.28.

NPEI is taking action to maintain its system reliability. NPEI has conducted a detailed review of its distribution assets and prepared a comprehensive plan, which provides for the renewal of its distribution system over the period 2015 - 2019. 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.

NPEI's SAIFI was 1.63 in 2019 which is higher than the target of 1.30.

Asset Management

Distribution System Plan Implementation Progress

Distribution system plan implementation progress is a new performance measure instituted 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 per the DSP. NPEI filed its DSP with its Cost of Service rate application for 2015. NPEI achieved 99.27% (2017 = 100.69%) completion at December 31, 2018 of its 2018 capital budget.

As at December 31, 2019, NPEI completed 88.79% of its 2019 capital budget.

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 2018, 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 2018, 39.4% (26 distributors) of the Ontario distributors were ranked as "average efficiency"; 40.9% (27 distributors) were ranked as "more efficient"; 19.7% (13 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.

NPEI is forecasting to be in Group 3 for 2019.

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 2018 is $755 /customer which is a 1.9% increase over 2017 (2017=$741 /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 and the renewal and growth of the distribution system, have all contributed to increased operating and capital costs. 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 initiatives will continue in order to ensure customers have an opportunity to share their viewpoint on NPEI's capital spending plans.

NPEI is forecasting a Total Cost per Customer of $793 for 2019.

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. NPEI's 2018 rate is $20,745 per km of line, a 2.3% increase over 2017 (2017=$20,285 per km). See above cost per customer section for cost drivers commentary. NPEI continues to seek innovative solutions to help ensure cost/km of line remains competitive and within acceptable limits to our customers.

NPEI is forecasting a Total Cost per Km of Line to be $21,790 for 2019.

Public Policy Responsiveness

Conservation & Demand Management

Net Cumulative Energy Savings

NPEI's target for the 2015-2020 Conservation First Framework is energy savings of 74.44 GWh to be achieved over the six-year period. At the end of 2018 which is the fourth year of the new framework, NPEI has achieved 72.0% of the total six-year target. On March 20, 2019, the Minister of Energy, Northern Development and Mines issued a directive to the IESO that concluded the Conservation First Framework.

Connection and 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 2018, NPEI completed 3 CIAs for renewable generation facilities, all within the prescribed 60-day timeframe.

NPEI achieved 100% for 2019 for renewable generation connection impact assessments completed on time.

New Micro-Embedded Generation Facilities Connected On Time

In 2018, NPEI connected 23 new micro-embedded generation facilities (microFIT or 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.

NPEI achieved 100% for 2019 for new Micro-embedded generation facilities completed on time.

Financial Performance

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 2018 is 1.44 (2017 = 1.59).

NPEI's forecasts a current ratio for 2019 to be 2.13.

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 2018 is 0.92 (2017 = 0.97). NPEI continues to monitor its debt to equity ratio on an annual basis.

NPEI is forecasting the debt to equity ratio for 2019 to be 0.99.

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 interim 2015 rates were based on a Working Capital Allowance (WCA) placeholder of 13%. NPEI was directed by the OEB to file a lead/lag study with its 2016 Rate Application. The final Board-approved WCA was 10.48%. As a result, NPEI had a 2015 Interim Rate Rider that repaid the difference between the placeholder and final WCA percentages from May 2016 to April 2017.
NPEI's regulated rate of return achieved in 2018 is 5.03% (2017 = 3.57%). The rate of return achieved in 2018 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 distribution operations expense, due to succession planning and a higher level of overhead operations expense.
- Increased billing expenses, due to succession planning, higher meter reading costs and increased hardware and software maintenance expenses.
- Increased general and administrative expenses due to a new cyber security program and succession planning.

NPEI is scheduled to file its next Cost-of-Service rate application with the OEB in April 2020 for rates effective January 1, 2021.

NPEI achieved a Return on Equity of 4.73% for 2019.

EXTERNAL BENCHMARKING

1.8.4 External Benchmarking

NPEI monitors the performance of its peers using the published OEB yearbook and the annual scorecard measures. NPEI's peers include similar customer counts and similar square Km of Line or similar density of customers. NPEI also compares itself to the industry as a whole.

Table 1.8.4-1 Scorecard-Customer Focus

Distributor	Number of Customers	New Residential/ Small Business Services Connected on Time	Scheduled Appointments Met on Time	Telephone Calls Answered on Time	First Contact Resolution	Billing Accuracy	Customer Satisfaction Survey Results
Niagara Peninsula Energy	55,593	93.33%	98.89%	85.87%	91.00%	99.06%	95.00%
Burlington Hydro	67,940	98.31%	99.81%	83.28%	91.00%	99.76%	94.00%
Energy +	65,402	99.10%	99.94%	88.89%	99.75%	99.99%	A
Entegrus Powerlines	59,186	97.95%	99.73%	71.01%	81.00%	99.90%	94.00%
Enwin Utilities	88,978	100.00%	99.71%	76.93%	98.63%	99.72%	86.00%
Guelph Hydro Electric System	55,673	92.26%	96.81%	71.71%	100.00%	99.95%	89.00%
Oakville Hydro	72,108	95.16%	100.00%	85.20%	96.50%	99.99%	92.00%
Oshawa PUC Networks	58,745	99.78%	100.00%	90.10%	103	99.93%	95.00%
Thunder Bay Hydro Electricity Distribution	50,950	99.14%	100.00%	94.79%	A+	99.87%	A
Waterloo North Hydro	57,471	100.00%	99.33%	92.72%	99.87%	99.97%	96.00%
source 2018 OEB scorecards							

NPEI compares favourably with its peers, and has met all of the OEB Targets.

Table 1.8.4-2 Scorecard-Operational Effectiveness-Safety and System Reliability

Distributor	Level of Public Awareness	Level of Compliance with Ontario Regulation 22/04 (Target: substantially compliant)	Number of General Public Incidents	Rate per 10, 100, 1000 km of line	Average Number of Hours Power to Customer is interrupted	Average Number of Times Power to Customer is interrupted
Niagara Peninsula Energy	83%	C	0	0.000	1.98	1.65
Burlington Hydro	84%	C	0	0.000	1.44	0.85
Energy +	82%	C	1	0.672	0.46	1.19
Entegrus Powerlines	83%	NI	2	1.618	1.89	1.21
Enwin Utilities	82%	C	0	0.000	1.11	2.22
Guelph Hydro Electric System	86%	C	0	0.000	0.26	0.68
Oakville Hydro	83%	C	0	0.000	0.62	0.80
Oshawa PUC Networks	85%	C	0	0.000	1.34	1.29
Thunder Bay Hydro Electricity Distribution	84%	C	0	0.000	2.33	2.88
Waterloo North Hydro	82%	C	6	3.645	0.92	1.32

NPEI has comparable results to its peers on these measures of operational effectiveness. NPEI will continue to trend feeder performance and evaluate technical alternatives to correct deficiencies. During 2017-2018, NPEI competed a multi-year project which provides a tie point to a second source of supply to the Jordan area from the NWTS M5. This area was previously serviced by a radial supply from the Vineland 4501F1 feeder which has experienced degradation in SAIDI and SAIFI due to lack of redundancy. The total cost of the multi-year implementation was $1.4M.

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.

A significant factor contributing to the increase in the average number of interruptions in 2018 are outages due to two high wind events that impacted the Niagara region on April 4, 2018 (affecting 11,052 of NPEI’s customers) and on May 4, 2018 (affecting 9,767 of NPEI’s customers). On both of these dates, Environment Canada issued a warning about strong winds, which gusted up to 100 km/h in the area. Excluding the impact of the outages due to high winds on April 4, 2018 and May 4, 2018 would result in an Average Number of Times that Power to a Customer is Interrupted for 2018 of 1.28.

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.

Table 1.8.4-3 Operational Effectiveness-Asset Management and Cost Control

Distributor	Number of Customers	Number sq Km	Number of Km of Line	Distribution System Plan Implementation Progress	Efficiency Assessment (1=most efficient 5 = least efficient)	Total Cost ($) per Customer	Total Cost ($) per Km of Line
Niagara Peninsula Energy	55,593	827	2,024	99.27%	3	$ 755	$ 20,745
Burlington Hydro	67,940	188	1,535	On Track	2	$ 627	$ 27,766
Energy +	65,402	562	1,510	On Plan	2	$ 662	$ 28,689
Entegrus Powerlines	59,186	132	1,243	60.41%	2	$ 563	$ 26,787
Enwin Utilities	88,978	121	4,668	97.30%	3	$ 717	$ 13,660
Guelph Hydro Electric System	55,673	93	1,152	98.78%	3	$ 669	$ 32,312
Oakville Hydro	72,108	139	1,914	On Track	3	$ 719	$ 27,071
Oshawa PUC Networks	58,745	146	985	70.20%	2	$ 569	$ 33,915
Thunder Bay Hydro Electricity Distribution	50,950	387	1,154	101.14%	4	$ 682	$ 30,130
Waterloo North Hydro	57,471	683	1,652	61.36%	3	$ 819	$ 28,499

NPEI's cost per customer is high when it is compared to its peers based on customer count, but its cost per customer is comparable to its peer based on number of service territory size and density. NPEI has 67 customers per square Km. NPEI's cost per Km of line is low compared to its peers due to the large size of NPEI's service territory relative to its peers.

Table 1.8.4-4 Public Policy Responsiveness

Distributor	Net Cumulative Energy Savings	Public Policy Responsiveness Renewable Generation Connection Impact Assessments Completed on Time	New Micro-Embedded Generation Facilities Connected on Time
Niagara Peninsula Energy	72%	100.00%	100.00%
Burlington Hydro	81%	100.00%	97.37%
Energy +	144%	100.00%	100.00%
Entegrus Powerlines	99%		100.00%
Enwin Utilities	64%	57.14%	100.00%
Guelph Hydro Electric System	126%	100.00%	100.00%
Oakville Hydro	97%		100.00%
Oshawa PUC Networks	83%	100.00%	100.00%
Thunder Bay Hydro Electricity Distribution	126%		
Waterloo North Hydro	80%	100.00%	100.00%
source 2018 OEB scorecards			

NPEI is comparable to its peers for all of the Public Policy Responsiveness measures.

Table 1.8.4-5 Financial Performance

Distributor	Liquidity: Current Ratio	Leverage Total Debt to Equity Ratio	Profitability: Regulatory Return on Equity Deemed	Profitability: Regulatory Return on Equity Achieved
Niagara Peninsula Energy	1.44	0.92	9.30%	5.03%
Burlington Hydro	2.50	0.80	9.36%	7.03%
Energy +	1.45	1.01	9.36%	8.68%
Entegrus Powerlines	1.34	1.22	9.19%	8.20%
Enwin Utilities	2.24	0.78	8.01%	4.35%
Guelph Hydro Electric System	1.33	1.56	9.19%	8.18%
Oakville Hydro	1.42	0.95	9.36%	10.65%
Oshawa PUC Networks	1.07	1.21	9.00%	7.93%
Thunder Bay Hydro Electricity Distribution	1.56	0.80	8.78%	8.93%
Waterloo North Hydro	1.08	1.14	9.19%	8.20%

NPEI's current ratio is comparable to its peers. NPEI is also well within the OEB's targeted Debt to Equity Ratio of 1.5:1 and is also comparable to its peers. For 2017 and 2018, NPEI was outside the 3 percentage points of its deemed return on equity of 9.30%.

NPEI's regulated rate of return achieved in 2018 is 5.03% (2017 = 3.57%). The rate of return achieved in 2018 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 distribution operations expense, due to succession planning and a higher level of overhead operations expense.
- Increased billing expenses, due to succession planning, higher meter reading and collection costs and increased hardware and software maintenance expenses.
- Increased general and administrative expenses due to a new cyber security program and succession planning.

Table 1.8.4-6 OM&A Costs, Predicted Capital Costs, Total Cost per customer

	Niagara Peninsula Energy	Burlington Hydro	Energy +	Entegrus Powerlines	Enwin Utilities	Guelph Hydro	Oakville Hydro	Oshawa PUC Networks	Thunder Bay Hydro	Waterloo North Hydro
OM&A Costs										
Operations and Maintenance	6,973,053	9,477,152	5,956,450	4,207,899	9,064,723	6,215,415	9,203,837	3,154,342	8,437,852	7,367,037
Administration	10,353,868	8,548,783	11,721,522	9,368,125	16,490,863	10,151,739	8,711,461	9,946,092	7,030,936	6,470,377
Total OM&A	17,326,921	18,025,935	17,677,972	13,576,024	25,555,586	16,367,154	17,915,298	13,100,434	15,468,788	13,837,414
Number of Customers	55,593	67,940	65,402	59,186	88,978	55,673	72,108	58,745	50,950	57,471
Number of FTE's	127	92	125	104	188	120	104	90	124	124
Customers per FTE	**438**	**738**	**523**	**569**	**473**	**464**	**693**	**653**	**411**	**463**
OM&A per Customer	**$ 312**	**$ 265**	**$ 270**	**$ 229**	**$ 287**	**$ 294**	**$ 248**	**$ 223**	**$ 304**	**$ 241**
OM&A per FTE	**$ 136,432**	**$ 195,934**	**$ 141,424**	**$ 130,539**	**$ 135,934**	**$ 136,393**	**$ 172,262**	**$ 145,560**	**$ 124,748**	**$ 111,592**
OM&A % Change from 2017	*-1.70%*	*2.00%*	*1.90%*	*3.70%*	*-3.60%*	*9.10%*	*2.10%*	*7.50%*	*0.50%*	*7.00%*
2018 Predicted Capital Cost	24,661,333	24,594,495	25,642,529	19,719,966	38,208,169	20,856,276	33,898,412	20,306,089	19,300,969	33,242,872
2018 Predicted Capital Cost per Customer	**$ 444**	**$ 362**	**$ 392**	**$ 333**	**$ 429**	**$ 375**	**$ 470**	**$ 346**	**$ 379**	**$ 578**
Capital Cost % Change from 2017	*6.76%*	*6.09%*	*6.16%*	*6.86%*	*5.76%*	*6.54%*	*7.44%*	*9.30%*	*6.89%*	*6.29%*
Total Cost per Customer	**$ 755**	**$ 627**	**$ 662**	**$ 563**	**$ 717**	**$ 669**	**$ 719**	**$ 569**	**$ 682**	**$ 819**
% Change in Total Cost from 2017	**3.20%**	**4.30%**	**4.40%**	**5.50%**	**1.90%**	**7.70%**	**5.60%**	**8.60%**	**4.00%**	**6.50%**
Total Cost/Customer % Change from 2017	**1.89%**	**3.13%**	**3.44%**	**1.44%**	**1.41%**	**7.21%**	**3.45%**	**6.95%**	**3.81%**	**5.95%**
source 2018 OEB yearbook										

NPEI's 2018 total cost per customer is higher than its peers based on customer count but lower than its peers based on service territory size and customer density. NPEI's 2018 total OM&A decreased 1.7% from 2017. NPEI's customer count increased by 674 or 1.22% in 2018 over the prior year. As a result, NPEI's Total Cost/Customer % change from 2017 was lower than its peers in 2018. NPEI has experienced growth in the last four years which has increase the customer driven system access capital projects which is the significant driver of the Total cost per customer.

COST TRENDS

1.8.5 Cost Trends

NPEI monitors its costs against other utilities and against itself for prior years. As reinforced in the recent customer engagement survey, costs were identified as being important to NPEI's customers. NPEI strives to balance the costs associated with customer driven system access projects, distribution expansion facilities projects and its capital renewal requirements.

NPEI's customer cost trends over the last 5 years and the projected 2019, 2020 and 2021 are shown in Table 1.8.5-1 below.

Table 1.8.5-1

	2015 Board Approved	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Bridge Year	2021 Test Year
OM&A Costs								
Operations and Maintenance	6,588,003	6,560,060	6,496,354	7,323,639	6,973,053	7,525,632	7,199,159	7,116,974
Administration	9,215,446	9,589,992	9,926,610	10,298,964	10,353,868	10,848,014	11,553,744	12,341,946
Total OM&A	15,803,449	16,150,052	16,422,964	17,622,603	17,326,921	18,373,647	18,752,903	19,458,920
Number of Customers	52,314	52,770	53,617	54,919	55,593	56,067	56,673	57,286
Number of FTE's	126	125	121	124	123	122	126	128
Customers per FTE	**416**	**421**	**442**	**443**	**454**	**461**	**451**	**448**
OM&A per Customer	**302**	**306**	**306**	**321**	**312**	**328**	**331**	**340**
OM&A per FTE	**125,604**	**128,953**	**135,347**	**142,198**	**141,421**	**151,025**	**149,330**	**152,023**
Predicted Capital Cost	22,859,848	23,134,791	23,616,489	23,049,793	24,661,333	25,588,440	26,617,338	27,454,030
Predicted Capital Cost per Customer	**437**	**438**	**440**	**420**	**444**	**456**	**470**	**479**
Total Cost	38,663,297	39,284,843	40,039,453	40,672,396	41,988,254	43,962,086	45,370,241	46,912,950
Total Cost per Customer	**739**	**744**	**747**	**741**	**755**	**784**	**801**	**819**

source OEB Benchmarking file

Note 1: Operations and Maintenance are adjusted for HV Adjustment and LV Adjustment per Benchmarking file

NPEI monitors its per customer cost trends in order to continue to meet the needs of its customers. The source for Predicted Capital Cost is the 2020 Benchmarking-Spreadsheet Excel file for the historical year 2018, forecasted 2019 Year, the Bridge Year 2020 and the 2021 Test Year. Appendix 1-33 includes a PDF version of the OEB's 2020 Benchmarking-Spreadsheet-Forecast-Model. A live Excel file has also been filed with this application.

EFFICIENCY ASSESSMENT

1.8.6 Efficiency assessment

NPEI has completed the 2020 Benchmarking Spreadsheet Forecast model and has attached the file as a live Excel model as part of this Application. Appendix 1-33 includes a PDF version of 2020 Benchmarking Spreadsheet Forecast Model. NPEI is very mindful of its stretch factor cohort and has made it a performance goal to stay within Cohort 3. As can be seen in Table 1.8.6-1 below, NPEI's cost performance is improving. NPEI will maintain its stretch factor Cohort 3 ranking.

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

PERFORMANCE TARGETS

1.8.7 Performance Targets

Each year, NPEI reviews the results of its Scorecard performance to identify targeted areas for improvement. Below is a general overview of targeted performance improvements over the next three years in each of the OEB Scorecard categories.

Customer Focus

Customer focus is a core value of NPEI. NPEI has continually exceeded the industry targets for both service quality and customer satisfaction. Since 2015, NPEI targeted an improvement in the connection of new Residential/Small Business services connected on time and Scheduled Appointments met on time. The target for 2020 for new Residential/Small Business services connection on time is 94% and Schedule Appointments met on time is 100%. Significant improvements in First contact resolution have been made through the mainstreaming of processes. The target for 2020 has been set at 96%. Calls answered on time have ranged from 82.70% to 87.99% between 2015 and 2019. In 2020, NPEI has returned to a full complement of customer service representatives and has set a target of 89% for 2020. Billing accuracy has ranged from 98.79% to 99.74% between 2015 and 2019. The target for billing accuracy is 99% in 2020. Customer satisfaction significantly improved from the 2017 customer satisfaction survey overall result of 86% to 95% in 2019. The next customer satisfaction survey is scheduled to take place in 2021.

Operational Effectiveness

Safety is a core value of NPEI. The business plan proposes a number of safety initiatives to increase public awareness about the danger of electricity. These include the development of additional "Lucky the Squirrel" public safety videos which now includes the participation of 31 other local distribution companies. These videos were posted in October 2018 on NPEI's website under Online Resources/Safety. Other public safety initiatives include additional training for contractors and first responders as well as ongoing safety presentations to Grade 5 and 6 students. NPEI's business plan proposes that the target for public safety should be focused on the activities to increase public awareness rather than the outcome of a survey. NPEI completed its bi-annual public awareness safety survey in 2020 as part of the Grid Smart City membership. This was in part to share the costs of the survey. The level of compliance with Ontario Regulations 22/04 was in compliance for NPEI for the years between 2015 and 2019. NPEI has set a target of zero (0) serious public electrical incidents for 2020. In 2019, NPEI experienced two serious public electrical incidents; one was an accident whereby a third party contractor performing excavation work hit a pole and one was an individual attempting to steal copper from one of NPEI's pad-mount transformers.

System Reliability was identified as a priority by NPEI's customers during its recent customer engagement process. A number of initiatives are included in this business plan and NPEI's budgets to improve its distribution system reliability. These initiatives include tree trimming and animal proofing to reduce outages due to "foreign contact" which is the second highest cause of unplanned outages. Weather events excluded the highest cause of unplanned outages is defective equipment. NPEI's Distribution System Plan proposes to replace end-of-life poles, cables and equipment to reduce outages due to asset failure. NPEI also purchased 36 fault indicators to speed up the patrolling time and isolate sections and identify problem areas on the feeders, especially in the Vineland area. In 2020, NPEI commenced using data analytics from its GIS mapping system to identify neighborhoods where unplanned outages occurred during the month. The map is reviewed and investigated for recurring unplanned outages to identify equipment failure issues. The 2020 budget includes lightning arresters to be installed on the feeders in the Vineland area of NPEI's service territory. NPEI has set a SAIDI target of less than 1.79 and a SAIFI target of less than 1.53 in 2020.

NPEI's asset management target is to complete a minimum of 90% of its capital budget in 2020. This target includes the assets transferred from customers for expansion facilities as well as the capital contributions received from customers. The capital contributions were significantly higher than the budgeted amount in 2019 resulting in 88.79%. NPEI's business plan maintains an efficiency assessment category of 3 as per the Pacific Economics Group (PEG) forecasting model.

Public Policy Responsiveness

Conservation and Demand Management (CDM) has been a core function of the utility for the last 10 years. Unfortunately, NPEI's role is ending post-2019 as the province has cancelled some programs and centralized the delivery of the remaining programs with the Independent Electricity System Operation (IESO). NPEI's business customers, however, have told NPEI through the customer engagement survey, that they value their relationship with the company and that they expect the utility to be a business partner with them, offering more proactive communications when it comes to power outages and cost-saving measures. NPEI transitioned the former CDM Manager to become the Customer Engagement Manager in June 2020. NPEI also budgeted to add a Key Accounts Coordinator in July 2020, to provide this value-added service for its larger customers. NPEI has set a target of 100% for both the renewable generation connection impact assessments completed on time and the new micro-embedded generation facilities connected on time for 2020.

NPEI will also monitor opportunities to deliver customer conservation programs to its customers in 2020 and 2021.

Financial Performance

Financial responsibility is also a core value of NPEI. NPEI's current ratio for liquidity remains strong as does the balance sheet. NPEI does not expect it will have to borrow funds in 2020 or 2021 and is targeting to achieve a return on equity of 5.0% in 2020. The total debt to equity ratio is expected to decline to 0.96 in 2020. The current ratio is expected to decline to 1.90 in 2020.

Exhibit 1: Administrative Documents

Tab 9 (of 10): Financial Information

FINANCIAL INFORMATION

1.9.1 Historical Financial Statements

NPEI's Audited Financial Statements for 2015, 2016, 2017, 2018 and 2019 are provided at Appendix 1-31.

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RECONCILATION OF AUDITED FINANCIAL STATEMENTS AND REGULATORY FINANCIAL RESULTS

1.9.2 Reconciliation of audited financial statements and regulatory financial results

NPEI has included the RRR reconciliations to the Audited Financial Statements for 2014, 2015, 2016, 2017, 2018 and 2019. See Appendix 1-32. Also, included is the original 2014 RRR reconciliation to the Audited Financial Statements for 2014 under IFRS and CGAAP. Adjustments to the 2014 net income as a result of transitioning from CGAAP to IFRS is included at the end of the attachment.

ANNUAL REPORT

1.9.3 Annual Report

Niagara Peninsula Energy Inc. does not prepare an Annual Report.

RATING AGENCY REPORTS

1.9.4 Rating Agency reports

Niagara Peninsula Energy Inc. does not have a rating agency report.

PROSPECTUS AND RECENT DEBT/SHARE ISSUANCE UPDATE

1.9.5 Prospectus and recent debt/share issuance update

Niagara Peninsula Energy Inc. has not had a recent public debt/equity offering and does not have a public debt/equity offering planned.

CHANGE IN TAX STATUS

1.9.6 Change in tax status

Niagara Peninsula Energy Inc. has had no changes in tax status.

EXISTING ACCOUNTING ORDERS AND DEPARTURES

1.9.7 Existing accounting orders and departures

Niagara Peninsula Energy currently has three existing accounting orders for Deferral and Variance accounts.

1) Under the proceeding EB-2014-0096, the Decision and Order dated May 14, 2015, the OEB directed NPEI to establish a deferral account to capture all incremental costs associated with the Lead-Lag Study. As per the Decision and Order dated May 12, 2016 for proceeding EB-2015-0090/EB-2015-0328, the OEB Findings states ***"The OEB also approves NPEI's request to keep the deferral account open, namely 1508 Other Regulatory Assets, Subaccount Working Capital Allowance Lead-Lag Study Deferral Account."*** In the 2016 IRM rate application NPEI disposed of $34,077 related to the Lead-Lag Study as an offset to the over-collection of revenues as a result of the difference in the default working capital allowance of 13% in the 2015 Cost of Service rate application and the approved Working Capital Allowance of 10.48% as a result of the Lead-Lag Study. NPEI requested the deferral account remain open at that time as all of the consultant and legal fees were not finalized. NPEI has a balance of $7,199.18 in the Subaccount for Lead-Lag Study which NPEI is requesting approval for disposal of in this 2021 Cost of Service rate application.
2) Under the proceeding EB-2014-0096, the Decision and Order dated May 14, 2015, the OEB accepted the Settlement Proposal at the oral hearing. Included in the Settlement Proposal was an Accounting Order for OPEB's. Niagara Peninsula Energy is following the Report of the OEB EB-2015-0040 dated September 14, 2017 Regulatory Treatment of Pension and Other Post-Employment Benefits (OPEB's) costs.

3) Under the proceeding EB-2014-0096, the Decision and Order dated May 14, 2015, the OEB accepted the Settlement Proposal at the oral hearing. Included in the Settlement Proposal was an Accounting Order for Mist Meters. Niagara is requesting approval for disposal of the Mist Meter Deferral and Variance account in the 2021 Cost of Service Rate application.

APPENDIX 4.2-B— ACCOUNTING ORDER-OPEB'S

Accounting Order

OPEB Deferral Account

NPEI shall establish the following deferral account effective January 1, 2015:

- **Account 1508 Other Regulatory Assets, Subaccount – Other Post-Employment Benefits Deferral Account**

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.

No carrying charges shall be recorded in this account.

Sample Journal Entry

The following is an example of the journal entry that will be made by NPEI.

To record the unrecognized actuarial gain relating to Other Post-Employment Benefits upon transition to IFRS, the following entry will be made. (Assuming unamortized accumulated OPEB actuarial gain of $1,570,621 as of January 1, 2015)

	$	
	Dr.	Cr.
OPEB liability (balance sheet)	1,570,621	
Other Regulatory Assets account 1508:		
Subaccount OPEB Deferral Account		1,570,621

APPENDIX 4.2-C—ACCOUNTING ORDER-MIST METER DEFERRAL ACCOUNT

Accounting Order – MIST Meters Variance Account

NPEI shall establish the following variance account effective January 1, 2015:

- Account 1508 Other Regulatory Assets
    - Subaccount – MIST Meters Variance Account

This account shall be used to record the variance in costs above or below $43,760 which is the amount included in the 2015 Test Year meter reading expense, relating to the implementation of MIST meters between 2015 and 2019, that may be incurred as a result of the amendment to section 5.1.3 of the Distribution System Code.

Disposition of the account is proposed to occur in NPEI's next cost of service rate application and will be subject to the Board's prudence review.

No carrying charges will be recorded on this account.

Sample Journal Entry

The following is an example of the journal entry that will be made by NPEI.

The example assumes that incremental MIST meter reading costs are higher than the amount included in the 2015 Test Year by $50,000. This amount is assumed for illustration purposes only.

	$

	Dr.	Cr.
Other Regulatory Assets account 1508:		
Subaccount MIST Meters Variance Account	50,000	
Accounts Payable		50,000

STATEMENT OF ACCOUNTING STANDARDS USED

1.9.8 Statement of accounting standards used

Historical financial results are presented using the MIFRS method of presentation for all years between 2015 and 2019. The 2020 Bridge Year and 2021 Test Year are presented using the MIFRS method of presentation. NPEI changed its capitalization policy related to capitalization of the stores and garage departments and the capitalization of training costs effective January 1, 2011. Therefore, there was no impact on the 2021 revenue requirement related to a change in capitalization policy. NPEI completed the transition of its PP&E from CGAAP to MIFRS in the 2015 COS rate application. Account 1575 and 1576 are being requested to be disposed on a final basis in this 2021 COS rate application. NPEI does not need to complete Appendices 2-EA, 2-EB and 2-EC.

ACCOUNTING TREATMENT OF NON-UTILITY BUSINESS

1.9.9 Accounting treatment of non-utility business

NPEI's Application has been prepared to show NPEI as a regulated entity, separately from its parent companies or any of its affiliates that are not regulated by the Board. No amounts associated with non-utility Businesses have been included in the costs proposed for recovery in this Application.

NPEI confirms that the accounting treatment it has used in this Application has segregated all non-utility activities from its rate-regulated activities. NPEI provides accounting services to Peninsula West Services Corporation and Peninsula West Power Inc. In 2018, the total revenues of $11,314 have been included in the Billing and Collecting expenses on the Audited Financial Statements and in account 5315 on the RRR Trial Balance. Total non-utility revenues billed to Peninsula West Power and Peninsula West services combined in 2019 was $11,194. For the Bridge year and 2021 Test year, non-utility revenues are budgeted at $11,194 and $11,418 respectively.

SUMMARY OF CHANGES IN ACCOUNTING POLICIES

1.9.10 Summary of changes in accounting policies

NPEI has not changed any of its accounting policies since the 2015 COS rate application. NPEI reviews its capitalization and amortization policies annually and has determined no changes are necessary.

Exhibit 1: Administrative Documents

Tab 10 (of 10): Distributor Consolidation

ACQUISITION OR AMALGAMATION DETAILS

1.10.1 Acquisition or amalgamation details

NPEI has not acquired or amalgamated with another local distribution company since its last 2015 Cost of Service Rate application.

APPROVED ACM OR ICM

1.10.2 Approved ACM or ICM

NPEI has not submitted to the OEB any ACM (Advanced Capital Module) or ICM (Incremental Capital Module) since the 2015 Cost of Service rate application.

Appendix 1-1

OEB Appendix 2-A-List of Requested Approvals

File Number:	EB-2020-0040
Exhibit:	1
Tab:	3
Schedule:	23
Page:	
Date:	8/31/2020

Appendix 2-A
List of Requested Approvals

The distributor must fill out the following sheet with the complete list of specific approvals requested and relevant section(s) of the legislation must be provided. All approvals, including accounting orders (deferral and variance accounts) new rate classes, revised specific service charges or retail service charges which the applicant is seeking, must be separately identified, as well being clearly documented in the appropriate sections of the application.

Additional requests may be added by copying and pasting blank input rows, as needed.

If additional requests arise, or requested approvals are removed, during the processing of the application, the distributor should update this list.

Niagara Peninsula Energy Inc. is seeking the following approvals in this application:

1		Approval to align NPEI's rate year to its fiscal and budget year with rates changing from May 1st to January 1st, effective January 1, 2021.
2		Approval to charge distribution rates effective January 1, 2021 to recover a service revenue requirement of **$37,840,675** which includes a revenue deficiency of **$2,395,224** as detailed in Exhibit 6. The schedule of proposed rates is set out in Exhibit 8.
3		Approval to adjust the Retail Transmission Rates-Network and Connection as detailed in Exhibit 8.
4		Approval to adjust the Low Voltage Rates as detailed in Exhibit 8.
5		Approval to adjust the Loss Factors as detailed in Exhibit 8.
6		Approval to continue to use the Transformer Allowance and Primary Metering Allowance for transformer losses.

7		Approval of the rate riders for disposition of the Group 1 and Group 2 Deferral and Variance Accounts as detailed in Exhibit 9 and approval of the rate rider for disposition of Impacts arising from the COVID-19 Emergency, sub-account - Foregone Revenues from Postponing rate implementation
8		Approval to dispose and discontinue the use of the following Deferral and Variance Accounts: a) Lead/Lag Study Variance account-sub-account 1508; b) Incremental Capital Charges (Hydro One) Variance account-sub-account 1508; c) Wireline Pole Attachments account-sub-account 1508; d) RCVA Variance Account-Account 1518; e) RCVA (STR) Service Transaction Variance Account-Account 1548; f) Stranded Meters Variance Account-Account 1555; g) MIST meter reading Variance Account-Account 1557; h) Accounting Changes under CGAAP-Account 1576; and i)Impacts arising from the COVID-19 Emergency, sub-account - Foregone Revenues from Postponing rate implementation
9		Approval of the rate rider for a one-year disposition of the Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) for lost revenue as presented in Exhibits 4 and 9 of this Application.
10		Approval of the micro-FIT service classification and monthly service charge proposed in Exhibit 8.
11		Approval of the Specific Service Charges proposed in Exhibit 8. NPEI is not requesting any new Specific Service Charges in this Application.
12		Approval of the Retail Service Charges proposed in Exhibit 8. NPEI is not requesting any changes to its current Retail Service Charges.

Appendix 1-2

NPEI 2020 Capital and Operating Budgets

niagara peninsula energy inc.

2020
Capital
&
Operating
Budgets

Table of Contents

Niagara Peninsula Energy
2019 Reforecast and
2020 Capital and Operating Budgets
Executive Summary

NPEI's mission, vision and values identified in its strategic plan are as follows:

Mission: To deliver safe, efficient, and reliable electricity with excellent customer service and community value, provided by engaged employees.

Vision: To be recognized as exceptional in delivering services and value, to our customers and communities.

Values: To conduct ourselves with commitment to the values of:

- Integrity- We are ethical and our actions are truthful and trustworthy;
- Fairness- We treat everyone equally and free of bias;
- Responsibility- We provide services with safety first for our customers and employees;
- Respect- We listen to each other, see the value that each member of the team brings, and respect the needs of our stakeholders, and
- Transparency- We are open and accountable for our actions and decisions

NPEI's strategic plan identifies six focus areas 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 will understand and deliver on customer expectations for reliable, high quality, cost-effective service by enhancing customer satisfaction and customer engagement.

NPEI is required to conduct a bi-annual customer satisfaction survey by the OEB. The company conducted its customer satisfaction survey in the second quarter of 2019. An overall customer satisfaction score of 95% of customers who are "very or fairly" satisfied was achieved in 2019 which is up from 86% in 2017. NPEI anticipates to exceed industry targets for: telephone calls answered on time, billing accuracy, and first contact resolution in 2019. 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. Managing Customer relationships training was completed in 2019. NPEI is in compliance with the new legislation relating to the disconnection ban of residential customers during the winter months. For the second year, 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. An important part of the Cost of Service rate application includes Customer Engagement. In 2019, NPEI completed an RFP (Request for Proposal) to complete an extensive project related to Customer Engagement. The final report will be available in January 2020. NPEI intends to expand its resources with respect to Customer Engagement in 2020.

Operational

NPEI will productively manage assets and resources to meet current and future customer needs by expanding the transformation and distribution systems to meet electrical needs of current and future customers. NPEI will effectively maintain and refurbish aging plant facilities and equipment, provide high level of service quality, enhance system performance and reliability while ensuring 100% level of compliance with the Ontario Regulation 22/04 and promote public safety awareness.

In 2019, 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 achieve 95% project completion of the projects identified in the annual capital plan which exceeds NPEI’s target of 90%. Subdivision lot servicing and connections exceeded the 2019 budget due to continued residential growth. NPEI continued the pole replacement program, the switchgear replacement program and MIST meter changes in 2019. Customer system access projects related to the upgrade of existing services and new service connections exceeded the budget in 2019.

As part of the OEB mandated MIST metering replacement program, NPEI anticipates it will complete the final 265 MIST meter changes in 2019. The original population of meters identified to be replaced was 915 in 2014. Of the 915 meters, NPEI determined 675 conventional meters to be replaced with MIST meters and 240 conventional meters to be replaced by smart meters. The OEB set a targeted timeline of August 2020 for these conventional meters to be replaced.

Projected load growth in the next 3 to 5 years in the Montrose Road and Bigger Road area as a result of the construction on the new Niagara South Hospital requires additional system capacity to be extended in this area. NPEI budgeted in 2019 to construct a second feeder south on Oakwood drive, with continuation under the QEW and over the Chippawa River. The MTO requested NPEI not to work in this area for the next three years as they are proceeding with work on the QEW bridge at Lyons Creek Road. As a result, this project has been deferred to future years.

On September 16, 2019, the Ontario Government confirmed the new South Niagara Hospital as Infrastructure Ontario listed the project in their Market Update for Projects in Pre-Procurement. NPEI engaged with parties representing this project to learn the timelines for construction of the new hospital and the distribution requirements. The hospital requires two independent sources of supply of electricity and the initial timeline outlines the opening of the hospital in December of 2026. The representatives from the hospital held several meetings with all parties encompassed in the off-site infrastructure early works. The current timeline projects construction of temporary power supply to be completed in 2022. In order to accommodate supply of 15MW of redundant power, NPEI will need to expand the capacity of its Kalar Road transformer station. NPEI has budgeted the installation of a second bus at the Kalar Road TS in 2021. Due to the long lead time required for the construction of the second bus, NPEI is requesting approval to issue a purchase order in the first quarter of 2020 so installation can take place in early 2021. NPEI has an initial plan to construct two feeders west of the Kalar Road TS toward Garner Road, south down Garner Road, across the Welland River, and then east towards Montrose Road. The construction of these two feeders will be phased from 2021 to 2023. This project is categorized as system access customer driven with initial budget estimates of $1.6M, $1.30M and $1.2M respectively in each of the years from 2021 to 2023. NPEI faces a challenge of crossing the Welland River and will pursue options in 2020. As a result of the construction of the new hospital, NPEI anticipates further growth in that area.

Another main driver for the increased system access customer driven projects in 2020 is the Canada Summer games coming to the Niagara Region in 2021.

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 continue to pursue the purchase of land related to a new transformer station in 2020.

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 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 are stored on-site until the facility can accommodate this equipment in 2020.

NPEI engaged a third party consultant in 2018 to report on its asset condition assessment ("ACA"). The results of an ACA are used as guidelines to project and prepare NPEI's Distribution System Plan ("DSP") which is filed with NPEI's Cost of Service ("COS") rate application. NPEI is requesting to change its rate year from May 1st to January 1st, effective January 1, 2021. NPEI is currently preparing the initial numerical documentation for its DSP which will be filed in April 2020. Upon review of the results of NPEI's customer engagement, NPEI may revise its DSP.

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 2019.

The Electrical safety survey measures the level of public awareness regarding electrical safety. NPEI achieved a Public Safety Awareness Index Score of 82% in 2019. This survey is conducted on a bi-annual basis and reported on NPEI's scorecard.

Public Policy

NPEI will successfully deliver public policies, be environmentally responsible and respond to the needs of our communities. Smart Grid initiatives to improve reliability will be implemented to accommodate embedded generation. NPEI will be environmentally responsible, continuously engage in its communications and continue to develop its corporate image.

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. In March 2019, the provincial government announced the cancellation of electricity conservation programs. Two NPEI resources will continue to complete the current CDM applications it has up to the end of 2020. One resource was relocated to NPEI's engineering department in April of 2019 and one resource was empowered to be the Project Manager for the Customer Engagement project.

People

NPEI will invest in a safe, healthy and engaging workplace that attracts, retains and develops employees who contribute their best. Health and safety awareness will be promoted for NPEI employees and its "Safety Culture" will be strengthened. NPEI will gain a mutual understanding of its employees' job expectations; provide the equipment, resources and training to do the job well. Feedback and recognition of employee and team performance will be provided on a timely and ongoing basis. Employees will be provided with development opportunities, integrated with a corporate succession plan to sustain operations.

NPEI continued to invest in a leadership development plan in 2019 for six of its management personnel. The leadership development plan includes leadership training and a one on one coaching program. An innovation committee was created in 2019 and will continue in 2020. Lines Proficiency training took place in 2019 for ten journey persons, and four apprentices continued with apprenticeship training. Lift truck training, privacy training, cyber security training, and Managing Customer relations training were completed in 2019. Safety continues to remain the number one priority for NPEI. The contract with NPEI's union (I.B.E.W.) expired March 31, 2019. Labour negotiations were completed in July 2019 whereby the Union ratified the new four-year contract on September 4th, 2019. The 2020 budget includes the negotiated competitive wage increase.

Financial

NPEI will deliver sustainable shareholder value and meet or exceed regulatory expectations. Long-term financial viability will be maintained and NPEI's balanced scorecard will be met or exceeded. NPEI will maintain regulatory compliance and meet or exceed the Ontario Energy

Board's (OEB) scorecard expectations. Shareholder value will continuously be enhanced and dividend expectations will be met.

NPEI has projected a net income of $1.7M and a regulatory net income of $2.7M for 2019. Earnings before interest, income tax and depreciation is projected at 39.2% in 2019 and 38.8% for the 2020 budget. NPEI expects to meet all debt covenants for 2019 and for the 2020 budgeted year. Regulatory compliance has been achieved in 2019 and NPEI will continue to ensure compliance with all OEB regulations. The total cost per customer in 2015 was $744; 2016 = $747; 2017 = $741 and 2018 =$755. NPEI provided a total dividend of $1.4M to its shareholders in 2019 and the same amount has been included in the 2020 budget.

NPEI's resources are currently preparing the 2021 budgets that will be filed as the basis of the COS rate application.

Information Technology

NPEI will continually improve with a focus on innovation and technology in all areas of the business and provide integrated solutions to meet customer and business needs.

With respect to information technology, NPEI invested in software additions in 2019 that 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 replacement of Microsoft's Project Accounting in Great Plains), and contact management in the CIS. NPEI also invested in a web browser based technology for the i-Net viewer which will eliminate individual licenses and provide greater remote access. Due to NPEI's third party vendor experiencing a cybersecurity incident, the implementation of customer connect has been delayed until 2020.

The Ontario Energy Board released a letter in March 2018, whereby LDC's are to complete a Cyber Security Readiness Report. NPEI filed a certification with the OEB as to its readiness on April 30, 2019. NPEI created a Cyber Security committee in 2018, 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.

Summary

In summary, NPEI's 2020 capital budget and OM&A budget are aligned with its strategic goals and objectives. The 2020 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. NPEI continues to monitor its strengths, weaknesses, threats and opportunities. NPEI's strategic plan has allowed for the corporation to continue to be agile as business and regulatory conditions change.

Niagara Peninsula Energy Inc.
Budget Report 2020

This report is prepared for the purpose of reviewing the significant factors affecting the 2019 and 2020 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.

2019 Projected Balance Sheet

Total assets are projected at $242M, which is up 4% or $10.2M from the 2018 total assets. This is mainly due to an increase in cash of $2.9M and an increase in net fixed assets of $7.2M.

Capital Additions 2019

Significant capital projects completed in 2019 are illustrated in the table below. The table also details the capital contributions received in 2019 which are recorded in the Liabilities section on the Balance Sheet.

Project	2019-Budget			2019-Forecast		
	Gross Capital Investment	Capital Contribution	Net Capital Investment	Gross Capital Investment	Capital Contribution	Net Capital Investment
Montrose Road - Oakwood to Biggar Road	794,610		794,610	31,258		31,258
Re-build Victoria Avenue -Claus Road to South Service Road	657,678		657,678	6,480		6,480
Re-build Victoria Avenue 7th Avenue Phase 2	0		0	233,847		233,847
Campden DS Tx Failure	0		0	150,641		150,641
Concession 2 Rd Relocate	263,333		263,333	254,368		254,368
Thorold Stone (Kalar -Montrose)	427,734		427,734	82,697		82,697
Portage - Mountain to Church's	420,236		420,236	290,397		290,397
Station 14 Elimination Ph III	1,475,867		1,475,867	1,319,490		1,319,490
Subdivision rehabilitation Carry Over	68,585		68,585	70,165		70,165
Mountain Road-St. Paul Street to Mewburn	0		0	352,389		352,389
KM3-Underground link (large commercial customer)	965,719		965,719	10,935		10,935
Murray TS J-Bus Metering	672,623		672,623	572,557		572,557
Kalar TS Power Transformer Dry Down Equipment	70,000		70,000	72,501		72,501
Kalar TS Additional Switchgear Design	125,000		125,000	112,500		112,500
Switchgear replacements	83,000		83,000	298,000		298,000
Additional sectionaling switches	21,275		21,275	-		-
1-Phase Hydraulic recloser-Centreville Road	23,015		23,015	36,017		36,017
Line relocations due to Municipal Road Improvements Program	517,813	(260,000)	257,813	78,702		78,702
Pole Changeouts-Smithville and Niagara Falls service areas	674,777		674,777	936,852		936,852
Kiosks	51,200		51,200	86,043		86,043
Sustainment	869,500		869,500	1,228,879		1,228,879
Transfer of expansion facilities from customers	1,000,000	(1,000,000)	0	1,000,000	(1,000,000)	0
Subdivision Lots	417,000	(417,000)	0	1,411,407	(1,411,406)	0
Subdivision Connections	482,004	(482,004)	0	359,966	(359,966)	0
Lot Rebates	0	700,000	700,000		700,000	700,000
Demand (new services, service upgrades etc. both service areas)	1,269,425	(728,000)	541,425	3,069,691	(1,431,590)	1,638,101
Metering - General/MIST	401,800		401,800	476,885		476,885
	11,752,194	**(2,187,004)**	**9,565,189**	**12,542,665**	**(3,502,962)**	**9,039,702**
SA - System Access	5,455,558	(1,927,004)	3,528,554	6,472,642	(3,502,962)	2,969,679
SR- System Renewal	5,244,261	(260,000)	4,984,261	4,662,461	0	4,662,461
SS- System Service	1,052,375	0	1,052,375	1,407,562	0	1,407,562
	11,752,194	(2,187,004)	9,565,189	12,542,665	(3,502,962)	9,039,702

The 2019 distribution assets net additions after capital contributions are projected at $9.0M, which is $0.5M lower than the 2019 budget amount of $9.5M. 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 has been rescheduled to 2020 due to the increase in customer driven system access projects. The KM3 feeder new build project is contingent upon one of NPEI’s larger commercial customers signing a connection agreement. As at the end of October the customer had not signed an agreement with NPEI as they are awaiting permits from a Federal body. NPEI included this project in the 2020 capital budget.

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 the current year.

Significant 2019 subdivision projects include Cherry Heights extension, Warren Woods, Vista Ridge, Terravita subdivision and Old Town Gateway Estates. It is projected 480 lots will be connected in 2019.

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 between 2015 and 2020. During the past 5 years, the 915 meters were reviewed for customer demand. The total number of MIST meters to be replaced is 675, of which 265 were installed in 2019. The remaining 240 conventional meters were determined to be changed to a smart meter which will be completed in 2020.

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 impact on the income statement is an increase in meter reading expenses of $75K annually, effective in 2019.

Capital contributions for 2019 are projected at $3.5M which includes the transfer of expansion facilities from developers, owned by NPEI after the subdivision is energized, which is $1.30M higher than the 2019 budget of $2.2M.

Building expenditures are projected at $2.0M in 2019, which represent the costs related the construction of NPEI's new garage and truck washing facility. Since construction is ahead of budget due to favourable weather conditions, NPEI has reduced the original balance of $2.0M budgeted for in 2020 by $425K. Office equipment additions include a new sprinkler system, new security cameras and two mobile radio replacements. Computer hardware additions are projected at $192K, which mainly includes the replacement of six servers which reached end of life. Computer software additions are projected at $438K, which includes CIS updates for contact management and File Nexus. NPEI purchased Job Cost and Quadra in 2019. Quadra is a software program used for engineering design and estimating which interfaces with Job Cost, a third party module in Great Plains. In the GIS system, NPEI installed Networks Professional, which allows for the upgrade to a browser based iNet-viewer versus the purchase of individual licenses.

Vehicles < 3 tonnes are projected at $40K, which includes the replacement of 1 pick-up truck. Vehicles > 3 tonnes are projected at $510K, and includes a mini-track machine and the body for a new RBD (radial boom derrick) truck. The chassis was built in 2018. Tools and Equipment are projected at $93K.

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 2019 is projected at $123K.

Liabilities and Share Holders Equity 2019

Current liabilities are projected to be $19.5M at the end of 2019. This is a decrease of $10.2M or 34%. The current portion of long-term debt decreased due to the 2019 loan being refinanced in November 2019. There are no loans due in 2020.

Non-current liabilities are projected to be $20M higher at the end of 2019. In August 2019, NPEI refinanced the two notes payable to the shareholders at the request of the shareholders. Both of these twenty year notes, totaling $25.6M, were coming due in April 2020 and carried an interest rate of 4.77%. NPEI issued an RFP to refinance these long term debt instruments. The new debt carries an interest rate of 2.76% for a period of ten years with monthly interest only repayments. NPEI had a long term $10M loan with TD Bank which came due in November 2019. The $10M loan was refinanced with Scotiabank over a five-year term, interest only repayments at an interest rate of 2.698%. NPEI incurred new debt in the amount of $8M in 2019. The new loan with Scotiabank has an interest rate of 2.698%, over a five-year term and ten -year amortization period. Monthly principal and interest payments will commence in November 2019.

In 2019, NPEI paid a total dividend of $1.4M to its shareholders proportionate to the shares held.

2019 Projected Income Statement

Regulatory Net Income does not include the depreciation expense for the FMV bump of $1,047K. Projected 2019 regulatory net income after tax and net movement in regulatory balances is $2.7M which is $170K greater than budget and $1.7M lower than 2018.

The Gross profit is projected at $2.9M greater than budget and $3.7M greater than 2018.

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 2019, NPEI's residential fixed service charge moved from 89.6% to 100%.

Other revenue in 2019 is lower than 2018 by $635K. 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. Due to the announcement by the Ontario Government to cancel all CDM programs in March of 2019, performance incentives have also been cancelled. Effective July 1st 2019, the OEB announced the cancellation of the $30 collection of account charge and a change in the calculation of late payment interest charges. Due dates of customer bills were extended thereby reducing the interest period for late payments. The Winter disconnection ban continued for the second year in 2019. As a result, Collection of Account and Interest Charges Revenues are projected to be $71K lower than 2018.

Cost of power is projected to increase from 2018 by $3.9M or 3%. In October, the OEB announced the new time of use rates will increase substantially to reflect the true cost of power as a result of refurbishing generation facilities and equipment across the province. In order to offset these increases in the time of use rates, the Ontario government announced a 31.8% Ontario provincial rebate. The new rates project monthly residential bills to increase by $1.99 or 2% which is in line with inflation. The new time of use rates and new rebate come into effect November 1, 2019.

Total expenses including depreciation are projected at $28.2M which is $148K over budget and $1,074K over 2018. Total operation, maintenance, utilization, billing & collecting and general administration expenses for 2019 are projected at $19,340 which is $71K over budget and $731K over 2018.

OM&A labour is forecasted to be $70K lower than budget and $339K or 2.88% higher than 2018. NPEI successfully negotiated a new four-year contract with the Union in 2019. The

wage increase was 2.1% in 2019. In October 2018, NPEI hired two IT specialists, wages for these employees were accounted for 3 months in 2018 and a full year in 2019. NPEI had 2 employees on maternity leaves in 2019. In 2019, NPEI had six retirements and one employee who left for other opportunities. Three new full-time employees and 2 contract employees were hired throughout 2019. Succession planning continues to be an important strategic priority in order to manage future risk.
NPEI completed the oil analysis testing for the Kalar Transformer Station and several of its distribution stations, as well as kiosk inspections, the kiosk inspection program is to be completed every three years. Lift truck training and Lines Proficiency training for ten journey persons were completed for the lines department personnel. Four apprentices attended the Mearie lineman training school at various levels in 2019. Pole inspections and pad-mount inspections are projected to be $93K and $69K respectively higher in 2019 versus 2018. This is due to the cyclical nature of annual inspections across NPEI's service territory. Engineering software maintenance fees are projected to be higher in 2019 with the addition of new GIS functionality.

Meter reading expenses are also higher in 2019 due to the loss of the base station owned by Grimsby Power from the wind storm, NPEI now owns two base stations which have an annual cost of approximately $75K. Meter reading expenses are projected to be $125K higher in 2019 over 2018, $75K relates to the two new base stations and the remaining relates to the conversion of conventional meters for the GS<50 rate class to either MIST meters or smart meters depending on the customer's demand. NPEI received approval from the OEB as part of its 2015 COS rate application to capture the increase in meter reading expenses as a result of the OEB's initiative to have this rate class converted to electronic meter reading devices. In the Net movement of Regulatory Assets and Liabilities line on the Income statement there is a corresponding offset to the increased meter reading expenses as an increase of $62K moving meter reading expenses to a Regulatory Asset on the Balance Sheet which will be requested to be disposed of as a rate rider in the 2021 COS rate application

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 $23K higher in 2019 and $22K higher than 2018.

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. Collection expenses relates to these accounts sent to a third party collection agency. These costs are projected to be $25K higher in 2019 offset by a decrease to bad debt expense of $28K.

Programming expenses are projected to be $29K higher in 2019 as a result of new software purchases and as a result of third party providers changing from a license based maintenance fee to a subscription based license fee.

Every two years NPEI is required to conduct a customer satisfaction survey with its customers. The survey was completed in 2019 with an overall satisfaction score of 95% which is up from 86% in 2017.

The Ontario Energy Board released a letter in March 2018, whereby LDC's are to complete a Cyber Security Readiness Report which was 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.

2020 Budget Balance Sheet

Total Assets are budgeted at $203M which is $8.30M higher than 2019 projected total assets. Capital additions of fixed assets in 2020 total $17.2M, which exclude capital contributions of $3.9M. Intangible asset additions included in the $17.2M total $0.3M.

Cash has decreased by $4.9M which is due to the 2020 capital investment and principle repayment of existing loans in the amount of $0.7M.

Effective May 1, 2020, there will be a new rate rider in effect for 12 months which relates to the recovery of deferral and variance account balances as at December 31, 2018 for the retail settlement variances (power, global adjustment, wholesale market, network and connection variances) in the amount of $1.4M.

NPEI does not have any long term debt coming due in 2020 and it does not intend to obtain any new financing.

NPEI included a dividend payment of $1.4M in the 2020 budget.

Capital Additions 2020

Total gross fixed asset additions for 2020, net of fixed asset disposals of $282K, are budgeted at $17.2M which includes software additions of $0.341M. Capital contributions are budgeted at $3.9M which results in a net capital budget of $13.4M.

Gross capital additions related to the distribution system are budgeted at $14.8M, less capital contributions of $3.9M which include $700K of lot rebates, for net total distribution system additions of $10.9M.

As in previous years, NPEI's 2020 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 2020 Capital Projects. Two capital projects: Thorold Stone Road-Montrose to Kalar overhead rebuild and the KM3-underground link projects were originally scheduled to be completed in 2019. Due to the magnitude of customer demand and subdivision projects in 2019, and NPEI's resources, these two projects were deferred. The Pin Oak main loop project is related to the construction of the new Costco store and the GPI feeder re-build is related to the rapid growth incurring in the Town of Grimsby. Overall, the system access budget of $9.4M before capital contributions accounts for 64% of NPEI's 2020 capital project budget. On a net basis after capital contributions, system access projects account for 52% of the 2020 capital project budget. The other main driver of the increased system access customer driven projects in 2020 is the Canada Summer games coming to the Niagara Region is 2021. Prior to the announcement regarding the new South Niagara hospital, NPEI's 2020 budget was 53% system renewal and 39% system access. 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.

Item	2020 Project	Gross Capital Investment	Capital Contribution	Net Capital Investment
1	Sinnicks Avenue-Rebuild	824,145		824,145
2	King Street-Rebuild	344,679		344,679
3	Thoroldstone Road-Kalar to Montrose Road Phase 2	349,274		349,274
4	Station 14 Elimination Phase 3	236,611		236,611
5	McRae Street-Rebuild Phase 1	351,194		351,194
6	Step Down Tx Elimination 9th Street	600,106		600,106
7	Pin Oak Main Loop	1,224,075		1,224,075
8	GPI Feeder Rebuild	807,178	(421,504)	385,674
9	KM3-Underground link (large commercial customer)	876,668		876,668
10	Stanley TS HONI initiated	625,765		625,765
11	Kalar TS relay upgrade	75,000		75,000
12	Greenlane at Ontario Tie	160,278		160,278
13	Thorold Stone to Bridge St Roundabout	452,235	(126,118)	326,118
14	Jordan UG Relocate	1,062,995	(530,906)	532,089
15	RR20 Roundabouts	254,825	(156,969)	97,856
16	Fallsview Blvd. UG Relocate	452,244	(200,040)	252,204
17	Switchgear replacements	86,218		86,218
18	Line relocations due to Municipal Road Improvements Program	54,390	(16,945)	37,445
19	Pole Changeouts-Smithville and Niagara Falls service areas	700,988		700,988
20	Kiosks	52,704		52,704
21	Smartgrid	68,450		68,450
22	Sustainment	873,020		873,020
23	Transfer of expansion facilities from customers	1,000,000	(1,000,000)	0
24	Subdivision Lots	418,358	(418,358)	0
25	Subdivision Connections	483,334	(483,334)	0
26	Demand (new services, service upgrades etc. both service areas)	2,003,914	(1,200,000)	803,914
27	Metering - General	397,300		397,300
28	Lot Rebates		700,000	700,000
		14,835,948	**(3,854,173)**	**10,981,775**
	SA - System Access	9,487,516	(3,854,173)	5,633,343
	SR- System Renewal	4,246,684	0	4,246,684
	SS- System Service	1,101,748	0	1,101,748
		14,835,948	(3,854,173)	10,981,775

Detailed descriptions of these capital projects can be found in the 2020 Capital projects section. See Appendix B.

NPEI will host customer engagement meetings for the Sinnicks Avenue, King Street, and McRae Street overhead re-build projects. 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 2020 budget for Other Capital Additions reflects the considerations of customer focus, encouraging operational effectiveness and responding to public policy.

Expenditures proposed in 2020 for the building include the completion 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 will enable NPEI to maintain a modern and reliable fleet, which improves efficiency, safety and reliability during the construction of capital projects.

The 2020 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 implementing Customer Connect, improving workflow efficiencies and integration of the core software programs as well as a focus on improving against cyber security threats.

Building

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 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. Construction of the new facility commenced in 2019 and completion is expected in the second quarter of 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 $1.7M for building expenditures is included in the 2020 capital budget. See Appendix A.

General Equipment

In 2020, NPEI has budgeted $15K for general equipment, and $10K for ergonomic office equipment, $5K for 2 mobile radio replacements, $30K for the replacement of security cameras and the replacement of a photocopier that is at end of life. See Appendix C.

Hardware and Software

The Information Technology capital expenditures for 2020 focus on redundancy, security, business continuity, growth, and process efficiencies.

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 2020 budgeted expenditures of $170K are related to the following business needs:

- Replacement of network switches, physical servers, telephones, PC's, monitors and tablets/laptops which are at end of life

See Appendix D for more details.

Software

Software required for workflow efficiency and new requirements has been budgeted at $0.341M.

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 $190K for vehicles and transportation equipment in 2020. This includes the replacement of a metering van for $40K. NPEI will purchase the chassis for a bucket truck in 2020. Due to the length of time to construct these large vehicles, the balance of the body for the bucket truck is included in the 2021 budget. See Appendix F for details.

Tools and Equipment for Vehicles

Tools and equipment in the amount of $65K 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. 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.

2020 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. By the end of 2020, NPEI will have completed all but one of the projects identified in the 2015 DSP. The replacement of meters at the NWTS project identified in the DSP was not required. NPEI will filing a new DSP and COS rate application in April 2020, for rates effective January 1, 2021. The 2021 DSP will identify distribution system access requirements and a detailed system renewal plan for the years 2021 to 2025.

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 recently put on hold a consultation related to rate design for the general service class 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 2019, NPEI's residential fixed service charge moved from 89.6% to 100%.

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 2020 Distribution Revenue is based on the 2020 IRM rate application that was submitted to the OEB in August 2019. 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 2020, the Price Escalator is 2.0%, the productivity factor is 0% and NPEI's stretch factor is 0.3%, resulting in a 1.7% rate increase. NPEI has accounted for a growth in residential distribution revenue in the 2020 budget as well as the IRM rate increase which is effective May 1, 2020 pending approval by the Ontario Energy Board.

<u>Cost of Power</u>

Cost of power is budgeted at $148M in 2020 which is $5.9M higher than the 2019 projected and $9.8M higher than 2018.

<u>Other Revenue</u>

Other revenue is budgeted at $1.2M which is comparable to the projected 2019 and lower than the 2018 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. Effective July 1, 2019, the OEB issued new customer service rules as follows: Collection of account charge will cease; disconnection and reconnection charges will not apply to eligible low-income customers and a reasonable time for payment arrangements will be offered by the LDC to the customer and with respect to late payment charges, the minimum payment period before interest can be charged was changed from 16 days to 20 days.

<u>OM&A Expenses</u>

NPEI developed its' operational, maintenance and general administration ("OM&A") distribution expenses based on the four outcomes noted above. Total OM&A expenses of $19.884M excluding interest expense and depreciation are reflected in the 2020 budget. The projected 2019 OM&A expenses total $19.34M and 2018 OM&A expenses total $18.609M. The 2020

OM&A expenses are budgeted at $545K higher than the 2019 projected and $1,276K higher than 2018.

The total increase of $545K or 2.8% over the projected 2019 OM&A consists mainly of a labour increase of $591K which is offset by decreases in outside purchases. The labour increase consists of the competitive wage increase of $242K, payroll overhead burden increase of $76K, increase of one and a half Customer Service representatives, whereby one returned from maternity leave in June 2019 and one and a half former CDM FTE's transitioned into various departments. One additional regulatory accounting personnel has been added in the second quarter of 2020.

Other distribution expenses excluding labour are budgeted to decrease by $46K from 2019 projected. The 2020 OM&A expenses includes a new Wellness program initiative with a third party vendor and a new attendance management program with an objective to reduce sick time expenses. There will be six apprentices attending the Mearie line school for apprentices and ten additional journey persons attending lines proficiency training in 2020. Working at Heights, Lift Truck, Utility Work Protection Code and First Aid training will be completed in 2020. The innovation committee and cyber security committees will continue to meet throughout 2020 as well.

NPEI intends to pursue the purchase of land related to a new transformer station in 2020.

Interest Expense

Interest expense is budgeted at $2.30M in 2020. No new financing is anticipated at the time this budget has been prepared. Interest expense is lower than the projected 2019 amount by $76K. NPEI refinanced the two shareholder promissory notes in August 2019 and a $10M loan in November of 2019, as well as obtained new financing in the amount of $8M. Finance income is budgeted in 2020 similar to the projected 2019.

Depreciation Expense

Depreciation expense excluding the depreciation on FMV adjustment of fixed assets is budgeted at $8.2M which is $427K higher than projected 2019 depreciation expense and $787K higher than 2018. The increase is a result of the 2019 additions of $15.4M where the half year rule applies for depreciation calculation.

Wages and Benefits

NPEI renegotiated a new four-year collective agreement in 2019. The new agreement expires March 31, 2023. The 2020 budgeted wages include a competitive increase comparable to inflation and an increase of 1% 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 2020. One and a half former CDM FTE's have been transitioned into other departments in the 2020 OM&A budget, one additional FTE in Regulatory and Accounting has been added and one and a half customer service clerk FTE's have been added.

Net Income After Taxes

Net income after taxes is budgeted at $1.8M which is $147K higher than the projected 2019 net income after taxes and $1,521K lower than 2018. 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 2020 budgeted Income Statement has recorded all regulatory activities in the Net movement in regulatory balances line. The change in Net movement in regulatory balances on the Income Statement is equal to the change in Regulatory balances on the Balance Sheet.

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 2020 Capital budget of $13,428,000 be approved. This is comprised of capital additions, $14,836,000 offset by capital contributions in the amount of $3,854,000 for net distribution additions totaling $10,982,000, general plant and equipment, including the building and net of disposals of $2,105,000. Also the 2020 Intangible asset budgeted additions of $341,000 be approved.

2. The 2020 total operating expenditures in the amount of $29,147,000 including depreciation and depreciation related to the fair market value bump are approved.

3. Approval to issue a purchase order in the first quarter of 2020 for the purchase of a second bus at Kalar Road transformer station up to $1.3M for delivery in early 2021.

Niagara Peninsula Energy
Financial Ratios
2015 to 2020

	2020 Budget	2019 Projected	2018 Actual	2017 Actual	2016 Actual	2015 Actual
EBITDA % (Earnings Before Income Tax, Depreciation & Amortization	38.81%	39.29%	49.77%	42.56%	44.03%	48.08%
Financial Statement Return on assets	1.39%	1.34%	2.20%	1.44%	2.66%	2.98%
F/S Return on Equity	3.30%	3.21%	5.28%	3.68%	6.53%	7.07%
Liquidity ratio	1.99	2.39	1.44	1.59	1.84	1.90
Ratio Debt/Total Assets	0.41	0.41	0.38	0.38	0.41	0.34
Debt/Equity Ratio	0.97	0.99	0.92	0.97	1.01	0.82
Calculation of Return On Equity (ROE) on a Deemed Basis	Not Available		5.03%	3.57%	6.86%	8.96%

# of Customers	56,815	56,201	55,593	54,919	53,617	52,770
Total OM&A (Exclude FMV bump)	$ 18,805,270	$ 18,371,210	$ 17,326,921	17,622,603	16,422,962	16,191,002
Total OMA Cost/Customer	330.99	326.88	311.67	320.88	306.30	306.82

Niagara Peninsula Energy
Projected Balance Sheet
As at December 31, 2019
(000's)

	Projected 2019	Actual 2018	$ Variance	% Variance
ASSETS				
Current Assets				
Cash	11,761	8,818	2,943	33%
Accounts Receivable	15,750	15,392	358	2%
Unbilled Revenue	14,247	13,917	330	2%
Due from Affiliated Companies				
Niagara Falls Hydro Holding Corporation	3	3	0	13%
Niagara Falls Hydro Services Inc.	3	3	0	13%
Peninsula West Services	7	7	0	1%
Payments in lieu of corporate taxes refundable	0	473	(473)	-100%
Inventories	1,404	1,412	(8)	-1%
Prepaid Expenses	1,137	1,227	(90)	-7%
	44,312	**41,251**	**3,061**	**7%**
Fixed Assets				
Land	1,231	1,231	0	0%
Buildings	20,922	18,912	2,010	11%
Distribution Stations	9,635	9,486	150	2%
Transformer Station	7,102	6,768	334	5%
Distribution lines				
Overhead	132,246	126,992	5,254	4%
Underground	116,208	113,260	2,948	3%
Distribution transformers	51,011	48,744	2,267	5%
Distribution meters	13,839	12,842	997	8%
Trucks and Equipment	21,989	20,937	1,052	5%
	374,184	359,171	15,013	4%
Less: Accumulated Depreciation	(190,266)	(182,540)	(7,726)	4%
	183,918	**176,631**	**7,287**	**4%**
Intangible Assets				
Land rights	1,732	1,732	0	0%
Computer Software	5,192	4,755	438	9%
Total Intangible Assets	6,924	6,487	438	7%
Less: Accumulated Depreciation intangible assets	(5,721)	(5,222)	(499)	10%
	1,203	**1,264**	**(61)**	-5%
Deferred tax asset	**9,321**	**9,321**	0	0%
Total non-current assets	**194,442**	**187,216**	**7,226**	4%
Retail Cost Variances	483	404	79	19%
Retail Settlement Variances	(1,728)	(165)	(1,563)	950%
Low Voltage Variances	1,618	1,656	(38)	-2%
Stranded Meters	(25)	(25)	-	0%
Other Regulatory Assets	(1,066)	(690)	(376)	54%
Mist Meter Variance	75	(38)	113	-295%
OPEB Forecast vs Actual Payment Differential	(0)	(0)		
Smart Metering Entity Variance	(23)	(39)	16	-40%
Regulatory related to income taxes	4,213	4,213	-	0%
Accounting Changes under GAAP (depreciation)	(161)	(168)	7	-4%
Deferral & Variance Recovery 2019 application	(342)	0	(342)	100%
Deferral & Variance Recovery 2018 application	(114)	(2,188)	2,074	100%
Deferral & Variance Adjust 2015 Interim rates	0	(19)	19	200%
Lost revenue adjustment mechanism	5	6	(1)	200%
Regulatory Assets and Liabilities	**2,933**	**2,947**	**(14)**	**0%**
Total assets and regulatory balances	**241,687**	**231,414**	**10,273**	**4%**

Niagara Peninsula Energy
Projected Balance Sheet
As at December 31, 2019
(000's)

	Projected 2019	Actual 2018	$ Variance	% Variance
LIABILITIES				
Current Liabilities				
Accounts Payable	7,894	7,480	414	6%
Power bill payable	9,054	8,954	100	1%
Taxes Payable	0	0	0	100%
Deferred OPA revenue & standard offer	980	941	39	4%
Customer Deposits	1,290	1,230	60	5%
Current Portion of long term debt	338	11,124	(10,786)	-97%
Total current liabilities	**19,555**	**29,729**	**(10,174)**	**-34%**
Non-Current Liabilities				
Note Payable to City of Niagara Falls	0	22,000	(22,000)	-100%
Note Payable to Niagara Falls Hydro Holding Corp.	0	3,605	(3,605)	-100%
Long Term Bank Loan	83,484	40,338	43,147	107%
Employee Sick Leave Liability	59	66	(8)	-11%
Non-current deposits	37	37	0	0%
Employee Future Benefits	4,125	4,021	104	3%
Deferred Capital Contributions	40,599	37,096	3,503	9%
Amortization capital contributions	(10,896)	(9,920)	(976)	10%
Deferred tax liabilities	11,403	11,403	0	0%
Total non-current liabilities	**128,812**	**108,646**	**20,166**	**19%**
Total liabilities	**148,367**	**138,376**	**9,992**	**7%**
Shares				
Share Capital	31,246	31,246	0	0%
Contributed Surplus	25,459	25,459	0	0%
Retained Earnings	36,615	36,333	281	1%
	93,320	**93,038**	**281**	**0%**
TOTAL LIABILITIES & EQUITY	**241,687**	**231,414**	**10,273**	**4%**

Niagara Peninsula Energy
Projected Statement of Operations vs Budget
For the year ending December 31, 2019
(000's)

	Projected 2019	Budget 2019	Projected vs Budget $ Variance	Projected vs Budget % Variance	Actual 2018	Projected 2019 vs Actual 2018 $ Variance	Projected 2019 vs Actual 2018 % Variance
SERVICE REVENUE							
Standard Supply Service	124,543	121,611	2,933	2%	117,389	7,154	6%
Wholesale, Network & Connection Charges	20,228	20,370	(143)	-1%	20,138	90	0%
Service Charge	22,698	22,852	(154)	-1%	20,193	2,505	12%
Distribution Volumetric Charge	8,066	8,005	61	1%	9,887	(1,822)	-18%
Regulatory revenue recoveries/(refund)	(2,689)	(2,845)	156	100%	(3,017)	328	-11%
Standard Supply Service Admin Charge	157	156	1	1%	158	(1)	-1%
Retailer Revenue	40	27	13	49%	27	13	49%
Other Revenue	1,224	1,081	143	13%	1,421	(197)	-14%
Conservation programs incentive	0	0	-	100%	438	(438)	100%
Capital Contributions	976	944	32	3%	894	82	9%
	175,242	172,199	3,043	2%	167,527	7,715	5%
Cost of Power							
Power Purchased	142,147	141,981	(166)	0%	138,155	(3,992)	-3%
Total Cost of Power	142,147	141,981	(166)	0%	138,155	(3,992)	-3%
Gross Profit Before Other Revenue	33,095	30,219	2,877	10%	29,372	3,723	13%
Expenses							
Operation and maintenance							
Distribution	7,465	7,348	(117)	-2%	7,286	(179)	-2%
Utilization	266	266	(0)	0%	289	23	8%
Billing & Collecting	6,112	6,133	20	0%	5,860	(252)	-4%
Administration & general	5,497	5,665	168	3%	5,175	(322)	-6%
Depreciation	7,809	7,887	77	1%	7,450	(360)	-5%
Depreciation on FMV adjustment of fixed assets	1,047	1,047	(0)	100%	1,064	17	2%
TOTAL EXPENSES	28,196	28,345	148	1%	27,123	(1,074)	-4%
Income from operating activities	**4,899**	**1,874**	**3,025**	**161%**	**2,249**	**2,650**	**118%**
Finance income	205	229	24	11%	260	(55)	-21%
Finance costs	(2,459)	(2,713)	(253)	9%	(2,688)	(228)	8%
Income before income taxes	**2,644**	**(610)**	**3,302**	**-541%**	**(179)**	**2,823**	**-1579%**
Income tax expense	(982)	(922)	60	-6%	(960)	(22)	2%
Net Income for the year	**1,662**	**(1,532)**	**3,242**	**-212%**	**(1,139)**	**2,801**	**-246%**
Net movement in regulatory balances, net of tax	19	3,043	3,024	99%	4,489	(4,469)	-100%
Net income for the year, net movement in regulatory balances and comprehensive income	**1,681**	**1,511**	**170**	**11%**	**3,350**	**(1,668)**	**-50%**

Statistics	Projected 2019	Budget 2019	Projected vs Budget		Actual 2018	Projected 2019 vs Actual 2018	
Cost of Power %	81.11%	82.45%	1.34	pts	82.47%	1.35	pts
Gross Profit % After Other Revenue	18.89%	17.55%	1.34	pts	17.53%	1.35	pts
Total Expenses as % of Total Revenue	16.09%	16.46%	0.37	pts	16.19%	0.10	pts
Net Income After Tax as % of Total Revenue	0.96%	0.88%	0.08	pts	2.00%	(1.04)	pts
Income Tax % of Net Income	37.14%	-151.20%	188.34	pts	-537.08%	574.22	pts
Other Revenue	0.70%	0.63%	0.07	pts	0.85%	(0.15)	pts
Distribution	4.26%	4.27%	0.01	pts	4.35%	0.09	pts
Utilization	0.15%	0.15%	0.00	pts	0.17%	0.02	pts
Billing & Collecting	3.49%	3.56%	0.07	pts	3.50%	0.01	pts
Administration & general	3.14%	3.29%	0.15	pts	3.09%	(0.05)	pts
Depreciation	4.46%	4.58%	0.12	pts	4.45%	(0.01)	pts
Net finance costs	1.29%	1.44%	0.16	pts	1.45%	0.16	pts

Niagara Peninsula Energy Inc.
Statement of Retained Earnings
for the year ending December 31, 2019
(000's)

	Projected 2019	Actual 2018
Retained Earnings, Beginning of Year	36,333	34,383
Net Income	1,681	3,350
Dividends on common shares	(1,400)	(1,400)
Retained Earnings, End of Period	**36,615**	**36,333**

Niagara Peninsula Energy Inc.
Statement of Cash Flows
For the year ending December 31, 2019
(000's)

	Projected 2019 $	Actual 2018 $
Cash Provided By (Used In):		
Operations		
Net income and net movement in regulatory balances	1,681	3,350
Adjustments for:		
Depreciation and amortization	7,311	6,965
Depreciation and amortization intangible assets	499	485
Depreciation expense on fair market value adjustment of fixed assets	1,047	1,064
Amortization of deferred revenue	(976)	(894)
Contributions received from customers	3,503	2,538
Net loss on disposal of property, plant and equipment	0	96
Proceeds on disposal of property, plant and equipment	0	0
Post-employment benefits	104	137
Interest expense	2,255	2,427
Employee's accumulated vested sick leave	(8)	5
Deferred tax expense	0	1,140
Current tax expense	982	(180)
	16,398	17,133
Changes in non-cash working capital components		
Accounts receivable	(358)	(3,046)
Due to/from related parties	(1)	(4)
Unbilled revenue	(330)	1,765
Materials and supplies	8	144
Prepaid expenses	90	(231)
Accounts payable and accrued liabilities	514	(4,570)
Customer deposits	60	234
Deferred revenue	39	408
	16,420	11,833
Regulatory balances	14	(4,489)
Income tax paid	(699)	(53)
Income tax received	190	1,117
Interest paid	(2,459)	(2,688)
Interest received	205	260
Net cash from operating activities	13,670	5,981
Investing activities		
Purchase of property, plant and equipment	(15,645)	(14,697)
Purchase of intangible assets	(438)	(289)
Proceeds on disposal of property, plant and equipment		5
Net cash used by investing activities	**(16,083)**	**(14,981)**
Financing activities		
Dividends paid	(1,400)	(1,400)
Proceeds from long-term debt	43,147	10,000
Repayment of long-term debt	(36,391)	(11,514)
Net cash from financing activities	**5,355**	**(2,914)**
Change in cash and cash equivalents	2,943	(11,914)
Cash and cash equivalents, beginning of year	8,818	20,732
Cash and cash equivalents, end of year	11,760	8,818

Niagara Peninsula Energy
Projected Capital Budget
For the year ending December 31, 2019
(000's)

	Projected 2019	Original Budget 2019	Projected vs 2018 Budget Variance	Actual 2018	Projected 2019 vs 2018 Variance	2015 Test Year Approved in Rate App
Land and Land Rights	0	0	0	0	0	0
Buildings & Fixtures	2,010	1,634	(376)	1,025	(985)	87
Sub Total	**2,010**	**1,634**	**(376)**	**1,025**	**(985)**	**87**
Distribution Station	150	0	(150)	15	(135)	0
Transformer Station	334	195	(139)	135	(199)	0
Overhead Distribution	5,553	5,631	77	6,014	461	4,505
Underground Distribution	2,948	4,224	1,275	3,269	321	3,514
Distribution Transformers	2,502	995	(1,508)	2,043	(459)	1,547
Meters/MIST meters	832	512	(321)	848	16	285
Smart Meters	223	197	(26)	208	(15)	143
Sub Total	**12,543**	**11,752**	**(791)**	**12,532**	**(10)**	**9,994**
Office Furniture & Equipment	87	45	(42)	115	28	33
Computer Equipment, Hardware	192	323	130	327	134	240
Vehicles < 3 tonnes	40	38	(2)	118	78	114
Vehicles > 3 tonnes	510	507	(3)	401	(110)	514
Vehicles transportation other	48	55	7	0	(48)	71
Stores Equipment	0	0	0	5	5	0
Tools, Shop & Garage Equipment	93	95	2	66	(27)	61
Measurement & Testing Equipment	0	0	0	0	0	1
Communication equipment	123	125	2	110	(13)	215
Miscellaneous equipment	0	0	0	0	0	1
Sub Total	**1,093**	**1,188**	**94**	**1,141**	**48**	**1,250**
Total Capital before capital contributions	**15,646**	**14,574**	**(1,072)**	**14,698**	**(948)**	**11,331**
Capital Contributions	(3,503)	(2,187)	1,316	(2,538)	965	(828)
Net property plant & equipment	**12,143**	**12,387**	**244**	**12,160**	**17**	**10,503**
Intangible assets						
Computer Software	438	549	111	289	(149)	369
Total Intangibles	**438**	**549**	**111**	**289**	**(149)**	**369**
Total Gross Capital Expenditures	**12,581**	**12,935**	**354**	**12,449**	**(132)**	**10,872**
Disposals	(632)	(508)	124	(1,336)	(704)	(314)
Net Captial Additions after disposals	**11,949**	**12,427**	**478**	**11,113**	**(836)**	**10,558**

APPENDIX B
List of Projects

Project	2019-Budget			2019-Forecast		
	Gross Capital Investment	Capital Contribution	Net Capital Investment	Gross Capital Investment	Capital Contribution	Net Capital Investment
Montrose - Oakwood to Biggar	794,610		794,610	31,258		31,258
Re-build Victoria Avenue -Claus Road to South Service Road	657,678		657,678	6,480		6,480
Re-build Victoria Avenue 7th Avenue Phase 2	0		0	233,847		233,847
Campden DS Tx Failure	0		0	150,641		150,641
Concession 2 Rd Relocate	263,333		263,333	254,368		254,368
Thorold Stone (Kalar -Montrose)	427,734		427,734	82,697		82,697
Portage - Mountain to Church's	420,236		420,236	290,397		290,397
Station 14 Elimination Ph III	1,475,867		1,475,867	1,319,490		1,319,490
Subdivision rehabilitation Carry Over	68,585		68,585	70,165		70,165
Mountain Road-St. Paul Street to Mewburn	0		0	352,389		352,389
Walker Expansion - KM3	965,719		965,719	10,935		10,935
Murray TS J-Bus Metering	672,623		672,623	572,557		572,557
Kalar TS Power Transformer Dry Down Equipment	70,000		70,000	72,501		72,501
Kalar TS Additional Switchgear Design	125,000		125,000	112,500		112,500
Switchgear replacements	83,000		83,000	298,000		298,000
Additional sectionaling switches	21,275		21,275	-		-
1-Phase Hydraulic recloser-Centreville Road	23,015		23,015	36,017		36,017
Line relocations due to Municipal Road Improvements Program	517,813	(260,000)	257,813	78,702		78,702
Pole Changeouts-Smithville and Niagara Falls service areas	674,777		674,777	936,852		936,852
Kiosks	51,200		51,200	86,043		86,043
Sustainment	869,500		869,500	1,228,879		1,228,879
Transfer of expansion facilities from customers	1,000,000	(1,000,000)	0	1,000,000	(1,000,000)	0
Subdivision Lots	417,000	(417,000)	0	1,411,407	(1,411,406)	0
Subdivision Connections	482,004	(482,004)	0	359,966	(359,966)	0
Lot Rebates	0	700,000	700,000		700,000	700,000
Demand (new services, service upgrades etc. both service areas)	1,269,425	(728,000)	541,425	2,771,485	(1,431,590)	1,339,895
Metering - General/MIST	401,800		401,800	476,885		476,885
Transformer Inventory				298,206		298,206
	11,752,194	**(2,187,004)**	**9,565,189**	**12,542,665**	**(3,502,962)**	**9,039,702**
SA - System Access	5,455,558	(1,927,004)	3,528,554	6,174,436	(3,502,962)	2,671,473
SR- System Renewal	5,244,261	(260,000)	4,984,261	4,960,667	0	4,960,667
SS- System Service	1,052,375	0	1,052,375	1,407,562	0	1,407,562
	11,752,194	(2,187,004)	9,565,189	12,542,665	(3,502,962)	9,039,702

Niagara Peninsula Energy
Budget Balance Sheet
As at December 31, 2020
(000's)

	Budget 2020	Projected 2019	$ Variance	% Variance	Actual 2018	$ Variance	% Variance
ASSETS							
Current Assets							
Cash	6,825	11,761	(4,936)	-42%	8,818	2,943	33%
Accounts Receivable	15,829	15,750	79	0%	15,392	358	2%
Unbilled Revenue	14,318	14,247	71	0%	13,917	330	2%
Due from Affiliated Companies							
Niagara Falls Hydro Holding Corporation	3	3	0	0%	3	0	13%
Niagara Falls Hydro Services Inc.	3	3	0	0%	3	0	13%
Peninsula West Services	7	7	0	0%	7	0	1%
Payments in lieu of corporate taxes refundable	0	0	0	0%	473	(473)	-100%
Inventories	1,376	1,404	(28)	-2%	1,412	(8)	-1%
Prepaid Expenses	1,148	1,137	11	1%	1,227	(90)	-7%
	39,509	**44,312**	**(4,802)**	-11%	**41,251**	**3,061**	**7%**
Fixed Assets							
Land and land rights	1,231	1,231	0	0%	1,231	0	0%
Buildings	22,690	20,922	1,768	8%	18,912	2,010	11%
Distribution Stations	9,635	9,635	0	0%	9,486	150	2%
Transformer Station	7,177	7,102	75	1%	6,768	334	5%
Distribution lines							
Overhead	137,913	132,246	5,667	4%	126,992	5,254	4%
Underground	123,112	116,208	6,905	6%	113,260	2,948	3%
Distribution transformers	52,187	51,011	1,176	2%	48,744	2,267	5%
Distribution meters	14,598	13,839	759	5%	12,842	997	8%
Trucks and Equipment	22,581	21,989	592	3%	20,937	1,052	5%
	391,125	374,184	16,941	5%	359,171	15,013	4%
Less: Accumulated Depreciation	(198,708)	(190,266)	(8,442)	4%	(182,540)	(7,726)	4%
	192,417	**183,918**	**8,499**	**5%**	**176,631**	**7,287**	**4%**
Intangible Assets							
Land rights	1,732	1,732	0	0%	1,732	0	0%
Computer Software	5,533	5,192	341	7%	4,755	438	9%
Total Intangible Assets	7,265	6,924	341	5%	6,487	438	7%
Less: Accumulated Depreciation intangible assets	(6,259)	(5,721)	(538)	9%	(5,222)	(499)	10%
	1,006	**1,203**	**(197)**	**-16%**	**1,264**	**(61)**	**-5%**
Total non-current assets	**193,423**	**185,121**	**8,302**	**4%**	**177,895**	**7,226**	**4%**
Deferred tax asset	**9,321**	**9,321**	0	0%	**9,321**	0	0%
Total non-current assets	**202,744**	**194,442**	**8,302**	4%	**187,216**	**7,226**	4%
Regulatory balances							
Retail Cost Variances	559	483	76	16%	404	79	19%
Retail Settlement Variances	(2,388)	(1,728)	(660)	38%	(165)	(1,563)	950%
Low Voltage Variances	795	1,618	(823)	-51%	1,656	(38)	-2%
Stranded Meters	(25)	(25)	0	0%	(25)	0	0%
Other Regulatory Assets	(1,341)	(1,066)	(275)	26%	(690)	(376)	54%
Mist Meter Variance	283	75	208	279%	(38)	113	-295%
OPEB Forecast vs Actual Payment Differential	(0)	(0)	0	0%	(0)	0	0%
Smart Metering Entity Variance	(23)	(23)	0	0%	(39)	16	-40%
Regulatory related to income taxes	4,213	4,213	0	0%	4,213	0	0%
Accounting Changes under GAAP (depreciation)	(161)	(161)	0	0%	(168)	7	-4%
Deferral & Variance Recovery 2019 application	(42)	(342)	300	-88%	0	(342)	100%
Deferral & Variance Recovery 2018 application	(114)	(114)	0	0%	(2,188)	2,074	-95%
Deferral & Variance Recovery 2020 application	732	0	732	100%	0	0	100%
Deferral & Variance Adjust 2015 Interim rates	0	0	0	0%	(19)	19	-100%
Lost revenue adjustment mechanism	5	5	-	0%	6	(1)	-24%
Total Regulatory balance	**2,491**	**2,933**	**(442)**	**-15%**	**2,947**	**(14)**	**0%**
Total assets and regulatory balances	**244,744**	**241,687**	**3,057**	**1%**	**231,414**	**10,273**	**4%**

Niagara Peninsula Energy
Budget Balance Sheet
As at December 31, 2020
(000's)

	Budget 2020	Projected 2019	$ Variance	% Variance	Actual 2018	$ Variance	% Variance
LIABILITIES							
Current Liabilities							
Accounts Payable	8,289	7,894	395	5%	7,480	414	6%
Power bill payable	9,325	9,054	272	3%	8,954	100	1%
Taxes Payable	200	0	200	100%	0	0	100%
Deferred OPA revenue & standard offer	125	980	(855)	-87%	941	39	4%
Customer Deposits	1,290	1,290	0	0%	1,230	60	5%
Current Portion of long term debt	729	338	392	116%	11,124	(10,786)	-97%
Total current liabilities	**19,958**	**19,555**	**402**	2%	**29,729**	**(10,174)**	**-34%**
Non-Current Liabilities							
Note Payable to City of Niagara Falls	0	0	0	0%	22,000	(22,000)	-100%
Note Payable to Niagara Falls Hydro Holding Corp.	0	0	0	0%	3,605	(3,605)	-100%
Long Term Bank Loan	82,775	83,484	(710)	-1%	40,338	43,147	107%
Employee Sick Leave Liability	61	59	2	4%	66	(8)	-11%
Non-current deposits	37	37	(0)	0%	37	0	0%
Employee Future Benefits	4,275	4,125	150	4%	4,021	104	3%
Deferred Capital Contributions	44,453	40,599	3,854	9%	37,096	3,503	9%
Amortization capital contributions	(11,967)	(10,896)	(1,071)	10%	(9,920)	(976)	10%
Deferred tax liability	11,403	11,403	0	0%	11,403	0	0%
Total non-current liabilities	**131,038**	**128,812**	**2,226**	2%	**108,646**	**20,166**	**19%**
Total liabilities	**150,995**	**148,367**	**2,628**	2%	**138,376**	**9,992**	**7%**
Shares							
Share Capital	31,246	31,246	0	0%	31,246	0	0%
Contributed Surplus	25,459	25,459	0	0%	25,459	-	0%
Retained Earnings	37,044	36,615	429	1%	36,333	281	1%
	93,749	**93,320**	**429**	**0%**	**93,038**	**281**	**0%**
TOTAL LIABILITIES & EQUITY	**244,744**	**241,687**	**3,057**	**1%**	**231,414**	**10,273**	**4%**

Niagara Peninsula Energy Inc.
Budgeted Statements of Operations
For the year ending December 31, 2020
(000's)

	Budget 2020	Projected 2019	2020 vs 2019 $ Variance	2020 vs 2019 % Change	Actual 2018	2020 vs 2018 $ Variance	2020 vs 2018 % Change
SERVICE REVENUE							
Standard Supply Service	127,341	124,543	2,797	2%	117,389	9,952	8%
Wholesale, Network & Connection Charges	20,676	20,228	449	2%	20,138	538	3%
Service Charge	24,245	22,698	1,547	7%	20,193	4,052	20%
Distribution Volumetric Charge	7,440	8,066	(626)	-8%	9,887	(2,448)	-25%
Regulatory revenue recoveries(refund)	432	(2,689)	3,120	-116%	(3,017)	3,448	-114%
Standard Supply Service Admin Charge	166	157	9	5%	158	7	5%
Retailer Revenue	44	40	4	11%	27	17	65%
Other Revenue	1,218	1,224	(6)	0%	1,421	(203)	-14%
CDM performance incentive	0	0	0	0%	438	(438)	
Capital Contributions	1,071	976	95	10%	894	177	20%
	182,631	175,242	7,389	4%	167,527	15,104	9%
Cost of Power							
Power Purchased	148,017	142,147	(5,870)	-4%	138,155	(9,861)	-7%
	148,017	142,147	(5,870)	-4%	138,155	(9,861)	-7%
Gross Profit Before Other Revenue	**34,615**	**33,095**	**1,520**	**5%**	**29,372**	**5,243**	**18%**
Expenses							
Operation and maintenance							
Distribution	7,271	7,465	194	3%	7,286	15	0%
Utilization	266	266	(1)	0%	289	22	8%
Billing & Collecting	6,610	6,112	(498)	-8%	5,860	(750)	-13%
Administration & general	5,738	5,497	(240)	-4%	5,175	(563)	-11%
Depreciation	8,237	7,809	(427)	-5%	7,450	(787)	-11%
Depreciation-FMV adj of fixed assets	1,026	1,047	21	2%	1,064	38	4%
TOTAL EXPENSES	**29,147**	**28,196**	**(951)**	**-3%**	**27,123**	**(2,024)**	**-7%**
Income from operating activities	**5,467**	**4,899**	**569**	**12%**	**2,249**	**3,219**	**143%**
Finance income	216	205	11	5%	260	(44)	-17%
Finance costs	(2,383)	(2,459)	76	-3%	(2,688)	305	-11%
Income before income taxes	**3,300**	**2,644**	**656**	**25%**	**(179)**	**3,479**	**-1946%**
Income tax expense	(1,029)	(982)	(47)	5%	(960)	(69)	7%
Net Income for the year	**2,271**	**1,662**	**609**	**37%**	**(1,139)**	**3,410**	**-299%**
Net movement in regulatory balances, net of tax	(442)	19	(461)	-2374%	4,489	(4,931)	-110%
Net income for the year, net movement in regulatory balances and comprehensive income	**1,829**	**1,681**	**147**	**9%**	**3,350**	**(1,521)**	**-45%**
Other comprehensive income for the year	0	0	0	0%	0	0	0%
Total comprehensive income for the year	**1,829**	**1,681**	**147**	**9%**	**3,350**	**(1,521)**	**-45%**

Statistics

Cost of Power %	81.05%	81.11%	0.07 pts	0.00%	(81.05) pts
Gross Profit % After Other Revenue	18.95%	18.89%	0.07 pts	17.53%	1.42 pts
Total Expenses as % of Total Revenue	15.96%	16.09%	0.13 pts	16.19%	0.23 pts
Net Income After Tax as % of Total Revenue	1.00%	0.96%	0.04 pts	2.00%	(1.00) pts
Income Tax % of Net Income	31.19%	37.14%	(5.95) pts	-537.08%	568.27 pts
Other Revenue	0.67%	0.70%	(0.03) pts	0.85%	(0.18) pts
Distribution	3.98%	4.26%	0.28 pts	4.35%	0.37 pts
Utilization	0.15%	0.15%	0.01 pts	0.17%	0.03 pts
Billing & Collecting	3.62%	3.49%	(0.13) pts	3.50%	(0.12) pts
Administration & general	3.14%	3.14%	(0.00) pts	3.09%	(0.05) pts
Depreciation	4.51%	4.46%	(0.05) pts	4.45%	(0.06) pts
Net finance costs	1.19%	1.29%	0.10 pts	1.45%	0.26 pts

Niagara Peninsula Energy Inc.
Statement of Retained Earnings
for the year ending December 31, 2020
(000's)

	Budget 2020	Projected 2019	Actual 2018
Retained Earnings, Beginning of Year	36,615	36,333	34,383
Net Income	1,829	1,681	3,350
Dividends on common shares	(1,400)	(1,400)	(1,400)
Retained Earnings, End of Period	**37,044**	**36,615**	**36,333**

Niagara Peninsula Energy Inc.
Statement of Cash Flows
For the year ending December 31, 2020
(000's)

	Budget 2020 $	Projected 2019 $	Actual 2018 $
Cash Provided By (Used In):			
Operations			
Net income and net movement in regulatory balances	1,829	1,681	3,350
Adjustments for:			
Depreciation and amortization	7,698	7,311	6,965
Depreciation and amortization intangible assets	538	499	485
Depreciation expense on fair market value adjustment of fixed assets	1,026	1,047	1,064
Amortization of deferred revenue	(1,071)	(976)	(894)
Contributions received from customers	3,854	3,503	2,538
Net loss on disposal of property, plant and equipment	0	0	96
Proceeds on disposal of property, plant and equipment	0	0	0
Employee future benefits	150	104	137
Interest expense	2,167	2,255	2,427
Employee's accumulated vested sick leave	2	(8)	5
Deferred tax expense	0	0	1,140
Current tax expense	1,029	982	(180)
	17,223	16,399	17,133
Changes in non-cash working capital components			
Accounts receivable	(79)	(358)	(3,046)
Due to/from related parties	0	(1)	(4)
Unbilled revenue	(71)	(330)	1,765
Materials and supplies	28	8	144
Prepaid expenses	(11)	90	(231)
Accounts payable and accrued liabilities	666	514	(4,570)
Customer deposits	0	60	234
Deferred revenue	(855)	39	408
	16,901	16,421	11,833
Regulatory balances	442	14	(4,489)
Income tax paid	(830)	(699)	(53)
Income tax received	0	190	1,117
Interest paid	(2,383)	(2,459)	(2,688)
Interest received	216	205	260
Net cash from operating activities	**14,346**	**13,670**	**5,981**
Investing activities			
Purchase of property, plant and equipment	(17,223)	(15,645)	(14,697)
Purchase of intangible assets	(341)	(438)	(289)
Proceeds on disposal of property, plant and equipment	0	-	5
Net cash used by investing activities	**(17,564)**	**(16,083)**	**(14,981)**
Financing activities			
Dividends paid	(1,400)	(1,400)	(1,400)
Proceeds from long-term debt	0	43,147	10,000
Repayment of long-term debt	(318)	(36,391)	(11,514)
Net cash from financing activities	**(1,718)**	**5,355**	**(2,914)**
Change in cash and cash equivalents	(4,936)	2,943	(11,914)
Cash and cash equivalents, beginning of year	11,761	8,818	20,732
Cash and cash equivalents, end of year	**6,825**	**11,761**	**8,818**

Niagara Peninsula Energy Inc.
Capital Budget 2020
For the year ending December 31, 2020
(000's)

	Appendix	Proposed Budget 2020	Projected 2019	Proposed Budget 2020 vs Projected 2019 Variance	Actual 2018	Test Year Approved in Rate App	Variance to Rate Application
Land and Land Rights	A	0	0	0	0	0	0
Buildings & Fixtures	A	1,768	2,010	(242)	1,025	87	1,681
Sub Total		1,768	2,010	(242)	1,025	87	1,681
Distribution Station	B	0	150	(150)	15	0	0
Transformer Station	B	75	334	(259)	135	0	75
Overhead Distribution	B	5,667	5,553	113	6,014	4,505	1,161
Underground Distribution	B	6,905	2,948	3,956	3,269	3,514	3,391
Distribution Transformers	B	1,431	2,502	(1,071)	2,043	1,547	(116)
Meters/MIST meters	B	529	832	(303)	848	285	244
Smart Meters	B	230	223	7	208	143	87
Sub Total		14,836	12,543	2,293	12,532	9,994	4,842
Office Furniture & Equipment	C	94	87	8	115	33	61
Computer Equipment, Hardware	D	170	192	(22)	327	240	(70)
Vehicles < 3 tonnes	F	40	40	0	118	114	(74)
Vehicles > 3 tonnes	F	150	510	(360)	401	514	(364)
Vehicles Transportation Other	F	0	48	(48)	0	71	(71)
Stores Equipment		0	0	0	5	0	0
Tools, Shop & Garage Equipment	G	65	93	(29)	66	61	4
Measurement & Testing Equipment		0	0	0	0	1	(1)
Communication equipment	H	100	123	(23)	110	215	(115)
Miscellaneous equipment		0	0	0	0	1	(1)
Sub Total		619	1,093	(474)	1,141	1,250	(631)
Total Capital before capital contributions		**17,223**	**15,646**	**1,577**	**14,698**	**11,331**	5,893
Capital Contributions	B	(3,854)	(3,503)	(351)	(2,538)	(828)	(3,026)
Net property plant & equipment		13,369	12,143	1,226	12,160	10,503	2,866
Intangible assets							
Computer Software	E	341	438	(97)	289	369	(28)
Total Intangibles		341	438	(97)	289	369	(28)
Total Gross Capital Expenditures including Capital Contributions		**13,710**	**12,581**	**1,129**	**12,449**	**10,872**	2,838
Disposals including scrap transformers		(282)	(632)	350	(1,336)	(314)	32
Net Captial Additions after disposals		**13,428**	**11,949**	**1,479**	**11,113**	**10,558**	2,870

APPENDIX A
Building 2020

	2020 Budget
Building	
Building Construction	1,574,000
Architect, Civil, Mechanical For Garage and Washing Bay	150,000
Replace 3 Rooftop Heat/AC Units	24,000
Station 23 Wall repair	10,000
LED lighting retrofit -CDM, CS, mailroom, Server Rm	20,000
Total	**1,778,000**
Solar panel revenue	(9,900)
	1,768,100

APPENDIX B
2020-List of Projects

Item	Project	Gross Capital Investment	Capital Contribution	Net Capital Investment
1	Sinnicks Avenue-Rebuild	824,145		824,145
2	King Street-Rebuild	344,679		344,679
3	Thoroldstone Road-Kalar to Montrose Phase 2	349,274		349,274
4	Station 14 Elimination Phase 3	236,611		236,611
5	McRae Street-Rebuild Phase 1	351,194		351,194
6	Step Down Tx Elimination 9th Street	600,106		600,106
7	Pin Oak Main Loop	1,224,075		1,224,075
8	GPI Feeder Rebuild	807,178	(421,504)	385,674
9	KM3-Underground link	876,668		876,668
10	Stanley TS HONI initiated	625,765		625,765
11	Kalar TS relay upgrade	75,000		75,000
12	Greenlane at Ontario Tie	160,278		160,278
13	Thorold Stone to Bridge St Roundabout	452,235	(126,118)	326,118
14	Jordan UG Relocate	1,062,995	(530,906)	532,089
15	RR20 Roundabouts	254,825	(156,969)	97,856
16	Fallsview Blvd. UG Relocate	452,244	(200,040)	252,204
17	Switchgear replacements	86,218		86,218
18	Line relocations due to Municipal Road Improvements Program	54,390	(16,945)	37,445
19	Pole Changeouts-Smithville and Niagara Falls service areas	700,988		700,988
20	Kiosks	52,704		52,704
21	Smartgrid	68,450		68,450
22	Sustainment	873,020		873,020
23	Transfer of expansion facilities from customers	1,000,000	(1,000,000)	0
24	Subdivision Lots	418,358	(418,358)	0
25	Subdivision Connections	483,334	(483,334)	0
26	Demand (new services, service upgrades etc. both service areas)	2,003,914	(1,200,000)	803,914
27	Metering - General	397,300		397,300
28	Lot Rebates		700,000	700,000
		14,835,948	**(3,854,173)**	**10,981,775**

	Gross Capital Investment	Capital Contribution	Net Capital Investment
SA - System Access	9,487,516	(3,854,173)	5,633,343
SR- System Renewal	4,246,684	0	4,246,684
SS- System Service	1,101,748	0	1,101,748
	14,835,948	(3,854,173)	10,981,775

PROPOSED N.P.E.I 2020 CAPITAL BUDGET PROGRAM

The NPEI 2020 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. Sinnicks Ave. - Rebuild

Project scope involves the replacement of 1.2km of urban overhead double 4.16kv circuits (built in 1949). The new pole line will consist of a single 3 phase 13.8kV circuit to connect the 12M43 to the 12M5 feeders as well as a single 3 phase 4.16kV circuit (under build) to connect the F183 (Swayze DS) to F176 (Virginia DS). The new double circuit pole line will consist of 34-new 55' wood poles, constructed in the same alignment as the existing pole line. The side streets (Keith St, Coholan St, Vine St, Harold St, Brooks St, Frances St, Carman St, Atlas St, Judith St) supplied from the existing double circuits have been previously rebuilt to 13.8kV utilizing dual voltage transformers which would be converted to 13.8KV upon completion of the rebuild. The project also includes a section of new underground primary consisting of a new 150m long concrete encased duct-bank from Swayze Drive to Sinnicks Ave for the 600Amp supply from the 12-M-43, and a 130m of cable replacement from Station #179 to Sinnicks Ave for the 600Amp supply from the 12-M-5. Benefits include improved system losses, Public & Personnel safety, improved equipment clearances, reinforcement and capacity increase of the supply in the area with redundancy provisions.

Estimated Cost: $ 824,145.14 ***-- Category SR Project #2020-TBD***

2. King St. - Phase 1 (Bartlett Rd. to Sann Rd.) - Rebuild

The Project Scope involves the rebuild of existing double circuit 3-phase 27.6kV and 8.32 kV primary line on King St in place, for approximately 1.0km from Bartlett Rd going East to Sann Road. Construction involves the installation of 18-new 55' poles for double circuit, transfer of existing primary cable on the 8.32kV, and installation of 1.0km of new 556kcMIL primary & 3/0 Neutral conductor with 3/0 spun bus. The Project is being initiated to provide a capacity increase on the 27.6kV tie between the F1 (Vineland DS) and 18M1 (Beamsville TS) and replace end of life equipment identified through NPEIs Asset Condition Assessment. Benefits include improved supply reliability and flexibility on the system during contingencies and system configuration.

Estimated Cost: $ 344,678.79 ***-- Category SR Project #2020-TBD***

3. Thorold Stone Rd-- Montrose to Kalar

Continuation of project started in 2019. 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 = $ 349,274.10 ***-- Category SR Project #2020-0004***

4. Station #14--Voltage Conversion Phase III

Completion of 2019 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 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: $ 236,611.24 -- Category SR Project #2020-0007

5. McRae St. - Rebuild- Phase 1

Overall project scope involves the replacement of a single three phase 4.16kV circuit (0.75km) plus 2.25km of a single phase 2.4kV circuit (built in 1960). The new overhead line will be constructed to 13.8kV standards with dual voltage transformers using 25-new 45' and 60-new 40' wood poles. Construction will assume the same alignment as the existing pole lines and include the following side streets; Second Ave, Third Ave, Stuart Ave, Fourth Ave, Heywood Ave, Florence, Detroit Ave, Ottawa Ave, Buchanan Ave, Stamford St, McRae St and Rosedale Dr. The area will be connected to the 13.8kV system at a future date. The project will include replacement of 26-single phase transformers, installation of 3kM of secondary bus and direct transfer of 465 residential services to the new bus. Due to the size of this project, it will be split into three phases. Benefits include improved system losses, improved equipment clearances, reinforcement & capacity increase of the supply in the area.
Estimated Cost: $ 351,194.10 -- Category SR Project #2020-TBD

6. Step Down Transformer Elimination – 9th Street

Project scope involves the replacement of 1.8 km of overhead single three phase 8.32kV circuit (built in 1960) with a single three phase 27.6kV circuit using 28 - new 45' wood poles, constructed in the same alignment as the existing pole line along Ninth Street. The project includes relocation of a bank of step-down transformers from south of Fourth Avenue to south of King Street and installation of a new single phase step-down transformer on King Street west of Ninth Street along with replacement of 15-single phase transformers, installation of 1km of secondary bus, and direct transfer of 33 residential services to the new bus. Benefits include improved system losses, improved equipment clearances, reinforcement, Public & Personnel safety, and capacity increase of the supply in the area.
Estimated cost: $ 600,105.66 -- Category SR Project #2020-TBD

7. Pin Oak Drive U/G Rebuild – Main Loop

Project scope involves the installation of a 13.8kV, 600A U/G feeder and associated switchgear as well as rebuilding the 200A loop along Pin Oak Drive and Canadian Drive from McLeod to Montrose. This work is required to support the new commercial development in the area.
Estimated Cost: $1,224,074.88 -- Category SA Project #2020-TBD

8. Build out of New Feeder for GPI – NWTS to Boundary

Project scope includes the construction of a new egress feeder from NWTS, North along Grimsby Road. East along Young Street to South Grimsby Rd. 6 then North to the NPEI-GPI boundary. NPEI existing plant will be relocated to these new poles, which will be framed to accommodate the new GPI circuit. This is a customer demand driven project with GPI being the customer.
Estimated Cost: $807,177.94 ($421,503.54 Recoverable) -- Category SA Project #2020-TBD

9. KM3 - Link - New Build (Tie Point)

Projected load growth of one of our larger commercial customers requires NPEI to off load and reconfigure the KM3 feeder which currently services their property in order to accommodate their needs. This will require the installation of a new 3-phase feeder connection which will link the KM3 to the 12M1, to allow shifting of significant KM3 load to the 12M1.
Estimated cost: $ 876,667.99 -- Category SA Project #2020-TBD

10. Stanley TS – Rebuild (Feeder Metering and Feeder Egress)
HONI is rebuilding half of their Stanley TS infrastructure, including a new power transformer, P&C building and switchgear for the B-Y bus. The HONI initiated work will result in NPEI installing new feeder egress on all 4 feeders connected to the B-Y bus along with new primary metering on each feeder. Current bus level metering on the J-Q bus must be converted to feeder level metering as per the IESO. All 6 feeders connected to the J-Q bus will require new primary metering on each feeder. All work is to be coordinated with HONI project schedule.
Estimated cost: $ 625,765.25 ***-- Category SR Project #2020-TBD***

11. Kalar TS – Protection Refurbishment – Phase 2
Kalar TS was placed in service in 2004. The station consists of 2 x 75 MVA power transformers connected to the Hydro One transmission system at 115kV. The existing relays, RTU, and associated protection and control (P&C) equipment are at end of life and require replacement. Two failures to date have been experienced. These devices were to be replaced with equipment to current day standards. The transfer trip relays were successfully changed in 2018 and one GE F-60 feeder relay changed in 2017. Compatibility issues with the replacement feeder relay were observed and GE has now indicated a resolution to the previous issues. This project is to complete the replacement of one GE feeder F-60 protection relay as well as the design work to replace the station RTU.
Estimated cost: $ 75,000.00 ***-- Category SR Project #2020-TBD***

12. 18M1 - 18M4 - New Build (Greenlane at Ontario Tie Point)
Project scope involves the installation of approximately 0.25km of 1000kcMIL underground primary cable in a new concrete encased duct-bank to create a tie on the 18M4 (Beamsville TS) system north of CN Rail Tracks and 18M1 (Beamsville TS) on Ontario Street & Greenlane Rd. Benefits include increased Customer reliability during contingencies, capacity increase for the area and reduced system losses.
Estimated cost: $160,278.09 ***-- Category SS Project #2020-TBD***

13. Thoroldstone Rd – Bridge St Roundabout
Project scope involves the relocation of two pad mount switchgears and associated ducting / cables to accommodate the construction of a new roundabout at the Thoroldstone Rd, Bridge Street, Victoria intersection. This is a municipality driven relocation request.
Estimated cost: $452,235.20 ($126,117.60 Recoverable) ***-- Category SA Project #2020-TBD***

14. Jordan Village UG Relocate
Project scope involves the replacement of existing overhead plant to underground construction in order to accommodate road works planned by the Town of Lincoln. This is a municipality driven relocation request.
Estimated cost: $1,062,995.43 ($530,905.94 Recoverable) ***-- Category SA Project #2020-TBD***

15. RR20 Relocates for Roundabouts
Project scope involves the relocation of existing overhead plant in order to accommodate road works planned by the Region. This is a municipality driven relocation request.
Estimated cost: $254,825.04 ($156,968.82 Recoverable) ***-- Category SA Project #2020-TBD***

16. Fallsview UG Relocate
Project scope involves the replacement of existing O/H distribution with relocated U/G along Fallsview Blvd. from Ferry St. to Robinson St. to accommodate Municipality driven road redevelopment.
Estimated cost: $452,244.10 ($200,040.32 Recoverable) ***-- Category SA Project #2020-TBD***

17. Pad-mounted Switchgear Replacement

The Underground Equipment Inspection Program has identified a requirement for replacement of air insulated pad-mounted switchgear units, with dead-front stainless steel enclosure SF-6 Gas Insulated Equipment, due to corrosion and contamination issues, which will continue at a rate of 1-Units per year. 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: $ 86,218.00 ***-- Category SR Project #2020-TBD***

18. 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: $ 54,389.75 (recoverable $ 16,944.88) ***-- Category SA Projects***

19. Pole Replacement - 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 as per OEB requirements (3 years/urban, 6 years/rural), with a total population of over 37,000. 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 imaged, guy guards are installed & down grounds are repaired/replaced as required, and the inspection results and images are stored within the Geographical Information System (GIS). An evaluation of the results is performed, with deficiencies addressed by the replacement of deficient poles, in a timely manner, through this Capital Program. The average cost per pole change is approximately $ 5,000.

Estimated Costs: $ 700,987.63 ***--Category SR Project #2020-1010/2010***

20. Kiosk Replacement - 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. For 2020 the plan is to replace 1 unit.

Estimated cost: $ 52,704.00 ***-- Category SR Project #2020-TBD***

21. Smart Grid

Installation of smart technologies onto the distribution system. These technologies include reclosers, fault indicators and switches. These devices will communicate real time system status to our Operators allowing them to make better decisions when operating the system. The devices will also be remotely operable by the Operators via our existing WiMax network. This will be an annual program which focuses on modernizing our distribution system to improve both system reliability and efficiency.

Estimated Cost: $ 68,450.00 ***-- Category SS Project #2020-TBD***

22. 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: $ 873,020.00 ***-- Category SS Project #2020-1007/2007***

23. New Residential Services (Subdivisions)

This Capital Program manages the installation and connection of new residential services within new and on-going residential developments such as subdivisions.

Estimated cost:	***Lot servicing of existing***	***$418,358.00***
	Connection and energizing of new subs	***$483,334.30***
	TOTAL	***$901,692.30***
	(Recoverable $ 901,692.30)	***-- Category SA Projects***

24. 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: $2,003,913.50 ***-- Category SA Project #2020-1008/2008***
(Recoverable $1,200,000.00)

25. 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: $ 397,300.00 ***-- Category SA Projects***

Project Total (excludes transfer of expansion facilities from customers)	***$ 13,835,948.14***
Recoverable (excludes transfer of expansion facilities from customers)	***$ 3,554,173.40***
TOTAL	***$ 10,281,774.74***

APPENDIX C
General Equipment - 2020

	2020 Budget
Ergonomic Office Equipment	10,000
Photocopier replacement	26,000
2 Mobile Radio replacements	4,500
Security cameras	30,000
Defibrilator replacements	8,800
General Equipment as needed	15,000
	94,300

Appendix D
Hardware 2020

	2020 Budget
Network	39,600
Physical Servers	25,000
Printers	700
Phones-replacement	32,000
PC / Monitor-replacement	27,600
Hearing equipment	8,000
Tablets/Laptops replacement	31,200
	164,100
Cell phones	6,000
	170,100

APPENDIX E
Software - 2020

	2020 Budget
Hexagon-GIS	150,000
Dess data	30,000
Forms-Silverblaze	10,000
Great Plains	50,000
Northstar-CIS	65,000
Website	36,000
	341,000

APPENDIX F
Vehicles and Transportation Other Equipment 2020

Description	2020 Budget
<u>Vehicles < 3 tonnes</u>	
Replace Meter Van #48 (2007)	40,000
Total	40,000

<u>Vehicles > 3 tonnes</u>	**2020 Budget**
Bucket Truck TR 42 (2003)-Chassis only	150,000
	150,000
Total	**190,000**

Disposals	
Meter Van TR#48	(26,853)
Total Vehicle Disposals	**(26,853)**

APPENDIX G
Tools Budget 2020

Tools and Equipment for Vehicles	2020 Budget
Miscellaneous Replacement Tools	12,000
Battery Tools	8,000
Stringing Blocks	1,200
Diagnostic Equipment	5,000
Concrete Saws, Generators, Water Pumps, Chainsaws	5,000
8-Ton Snack Block	3,000
Travellers - For 1000MCM and annual replacement	2,000
Meter base loggers	15,000
Primary Metering - Hotstick ammeter & stick	2,500
	53,700

Tools for Garage	
Various shop tools	11,000
Total tools for garage	**11,000**
Total Tool Budget	**64,700**

APPENDIX H

Communication Equipment - 2020

	2020 Budget
Wi-max project	100,000
Total	**100,000**

Niagara Peninsula Energy Inc.
Capital Budget 2012 - 2025
(000's)

	Actual 2015	Actual 2016	Actual 2017	Actual 2018	Reforecast 2019	Budget 2020	Budget 2021	DSP 2022	DSP 2023	DSP 2024	DSP 2025	2021 Test Year Rate App
Land and Land Rights	0	0	0	0	0	0	0	0	0	0	0	0
Buildings & Fixtures	469	53	288	1,025	2,010	1,768	482	400	265	15	15	236
Sub Total	469	53	288	1,025	2,010	1,768	482	400	265	15	15	236
Distribution Station	1	0	238	15	150	0	0	0	0	0	0	0
Transformer Station	0	0	57	135	334	75	1,700	0	0	0	0	1,700
Overhead Distribution	5,219	6,307	5,745	6,014	5,553	5,667	6,819	6,983	7,314	6,812	7,074	6,819
Underground Distribution	5,550	5,007	3,693	3,269	2,948	6,905	5,405	5,563	4,700	4,585	4,567	5,405
Distribution Transformers	2,319	1,508	1,905	2,043	2,502	1,431	1,812	1,943	2,221	2,268	2,322	1,812
Meters/MIST meters	185	331	939	848	832	529	268	271	276	279	284	268
Smart Meters/MIST meters	144	159	0	208	223	230	264	267	269	272	275	264
Sub Total	13,418	13,311	12,577	12,532	12,543	14,836	16,267	15,027	14,780	14,216	14,522	16,267
Office Furniture & Equipment	26	28	23	115	87	94	119	59	68	89	59	79
Computer Equipment, Hardware	249	241	332	327	192	170	261	427	435	373	199	339
Vehicles < 3 tonnes	236	75	177	118	40	40	80	80	80	120	120	96
Vehicles > 3 tonnes	254	643	699	401	510	150	420	420	420	420	270	390
Vehicle Other	0	75	0	0	48	0	50	165	45	20	20	60
Stores Equipment	55	0	0	5	0	0	0	0	0	0	0	0
Tools, Shop & Garage Equipment	67	119	93	66	93	65	63	79	84	79	82	77
Measurement & Testing Equipment	0	0	0	0	0	0	0	0	0	0	0	0
Communication equipment	66	302	33	110	123	100	125	125	125	125	125	125
Miscellaneous equipment	0	0	0	0	0	0	0	0	0	0	0	0
Sub Total	952	1,482	1,358	1,141	1,093	619	1,118	1,355	1,257	1,226	875	1,166
Total Capital before capital contributions	**14,839**	**14,847**	**14,222**	**14,698**	**15,646**	**17,223**	**17,867**	**16,782**	**16,302**	**15,457**	**15,412**	**17,668**
Capital Contributions	(5,600)	(3,995)	(2,181)	(2,538)	(3,503)	(3,854)	(2,583)	(2,585)	(2,587)	(2,587)	(2,587)	(2,583)
Net property plant & equipment	**9,238**	**10,852**	**12,041**	**12,160**	**12,143**	**13,369**	**15,284**	**14,197**	**13,715**	**12,871**	**12,825**	**15,085**
Intangible assets												
Computer Software	183	342	711	289	438	341	335	501	167	240	129	274
Total Intangibles	**183**	**342**	**711**	**289**	**438**	**341**	**335**	**501**	**167**	**240**	**129**	**274**
Total Gross Capital Expenditures	**9,421**	**11,194**	**12,752**	**12,449**	**12,581**	**13,710**	**15,619**	**14,698**	**13,882**	**13,111**	**12,954**	**15,359**
Fixed Asset Disposals	(504)	(496)	(989)	(1,336)	(632)	(282)	(565)	(565)	(565)	(565)	(565)	(565)
Net Captial Additions after disposals	**8,918**	**10,698**	**11,763**	**11,113**	**11,949**	**13,428**	**15,054**	**14,133**	**13,317**	**12,545**	**12,389**	**14,794**

Average Net Capital Expenditures - 9 year (2012 - 2020) **11,698**

6 year average 2020-2025 **13,478**

Average Fixed Asset additions COS rate Application 2015 net of average $850K capital contributions **10,558**

6 year average 2015-2020 **11,312**

Appendix 1-3

NPEI 2019 Capital and Operating Budgets

2019
Capital
&
Operating
Budgets

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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.

<u>Summary</u>

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	Walker 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.

Building

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					
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

	2019 Budget
Building	
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	Walker 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**

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 Walker Environmental Group. This work is part of an Offer to Connect and Economic Evaluation with WEG.

Projected load growth at WEG requires NPEI to off load and reconfigure the KM3 feeder which currently services the WEG 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**

Appendix 1-4

NPEI 2018 Capital and Operating Budgets

niagara peninsula energy inc.

2018 Capital & Operating Budgets

Table of Contents

Niagara Peninsula Energy Inc.
Budget Report 2018

This report is prepared for the purpose of reviewing the significant factors affecting the 2017 and 2018 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.

2017-Long Term Energy Plan (LTEP): Delivering fairness and choice

The Minister of Energy's message for 2017 is principally focused on the consumer while ensuring a reliable and innovative energy system. The focus of the 2017 LTEP is to make energy more affordable, and allow customers to make choices in their use of energy.

The Ontario Fair Hydro Plan was introduced June 1, 2017. The key elements of the plan are:

a) ensure affordable and accessible energy;
b) ensure a flexible energy system;
c) innovate to meet the future;
d) improve value and performance for consumers;
e) strengthen the province's commitment to energy conservation and efficiency;
f) respond to the challenge of climate change;
g) support First Nation and Metis capacity and leadership;
h) support regional solutions and infrastructure.

Pricing pilots are underway to help inform new electricity pricing plans that could give consumers greater choice and the ability to reduce their monthly electricity bills. The pilot projects are testing a variety of innovative price structures, including:

- Different ratios between on and off-peak prices;
- Different times for on- and off-peak periods;
- Prices that increase during critical peaks – the short time periods with extremely high demand; and
- Seasonal pricing plans that have a flat rate for spring and fall, and on- and off-peak price periods for summer and winter.

Some of the pricing pilots will be combined with smart technologies, such as smart thermostats, energy use apps and electric vehicles, to give customers additional ability to manage their electricity use.

The pilots have begun rolling out and will run for at least one calendar year. The results will help guide OEB decisions on potential new price plans that could give customers greater control, reduce their bills and help improve system efficiency.

Authority was given to the Ontario Energy Board to prohibit disconnections in the winter months.

The OEB has a new Consumer Charter which is to ensure all energy consumers have the right to a fair, reasonable and timely process for resolving their complaints.

The Minister of Energy is currently working with LDC's to redesign electricity bills to give consumers easily accessible information they find valuable and can use.

The net metering framework is currently being updated to increase the consumer's ability to generate their own renewable electricity and receive a credit on their hydro bill for any extra power they send to their local distribution company.

Ontario's Fair Hydro Plan reduced electricity bills by an average of 25 per cent for residential consumers and will hold any increases to the rate of inflation for four years. The impact of this energy price reduction has decreased the accounts receivable and unbilled balances on the balance sheet for both the projected 2017 and budget 2018 years. The Cost of Power has also decreased due to the per kWh price reduction.

The Ontario Electricity Support Program (OESP) was increased in 2017. The on-bill credits have increased by 50 per cent and more Ontarians were made eligible for the program.

Revenue Decoupling

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 2017, NPEI's residential fixed service charge moved from 68.7% to 79.19%. Beginning May 1, 2018, NPEI's residential fixed service charge will move to 89.6% and by May 1, 2019, NPEI's residential service charge will be 100% fixed.

2017 Projected Balance Sheet

Total assets are projected at $221M, which is down 1% or $1.7M from the 2016 total assets. This is mainly due to a decrease in Accounts Receivable an Unbilled revenue of $5.7M. Due to the lower time of use energy rates and the removal of the OESP charges the average outstanding monthly accounts receivable balances are lower.

Capital Additions 2017

Significant capital projects completed in 2017 are illustrated in the table below. The table also details the capital contributions received in 2017 which are now recorded in the Liabilities section on the Balance Sheet.

Project	Projected 2017 Investment	2017 Budget	2017 Budget Variance
Dorchester - McLeod to Dunn Phase 2	219,414	359,131	(139,717)
Oakwood Drive - Overhead replacement -deferred from 2016	11,512	600,819	(589,307)
Padmount Switchgear replacement program	221,369	250,000	(28,631)
Station #14 Voltage Conversion Phase I	579,849	589,623	(9,774)
Brown Road extension - Montrose to Blackburn	76,681	189,664	(112,983)
Subdivision Rehabilitation Allowance	399,224	245,151	154,073
Additional sectionalizing switches	54,142	73,000	(18,858)
Victoria Avenue Fly Road South PH 1- deferred from 2016	308,108	308,719	(611)
1-Phase Hydraulic Reclosure Upgrades	48,881	100,000	(51,119)
Jordan Road Voltage Conversion Phase IV	562,661	561,614	1,047
Downtown Core PILCDSTA De-commissioning	486,002	292,171	193,831
Dorchester Mountain to Riall - deferred from 2016	594,161	678,670	(84,509)
Lightning Mitigation Measures	-	30,000	(30,000)
NS&T Hwy OH Crossing	160,405	-	160,405
Chippawa Redundant Supply Upgrades Phase I	315,984	343,719	(27,735)
Heartland Road extension-Brown Road to Chippawa Creek	104,119	114,583	(10,463)
Station DS Power Transformer Replacement	187,883	200,000	(12,117)
Kalar TS Protection-Relay Upgrades	96,701	400,000	(303,299)
Line Relocations due to Municipal Road Improvements	241,514	500,000	(258,486)
Replacement of Poles identified with Structural Integrity	1,059,405	626,236	433,169
Kiosk replacement program	1,000,002	1,001,137	(1,136)
System Sustainment allowance	901,784	820,000	81,784
Subdivision Lot servicing of existing lots	818,784	275,000	543,784
Connection and energizing of new subdivisions	548,533	312,004	236,529
Subdivision Lot Rebates- new connections	581,400	250,000	331,400
Customer Demand Work	2,334,313	1,124,500	1,209,813
Metering - General and MIST	935,000	543,500	391,500
Total Distribution Assets	12,847,829	10,789,240	2,058,589
Building	357,000	373,000	(16,000)
Office furniture and equipment	23,000	20,000	3,000
Computer Hardware additions	403,000	401,390	1,610
Software additions	729,000	1,120,860	(391,860)
Fleet replacements excluding disposals and Tools	969,500	777,250	192,250
Wi-max communication-Niagara Falls Tower	32,000	120,000	(88,000)
Total General Plant & Equipment	2,513,500	2,812,500	(299,000)
Total Fixed Asset Additions	15,361,329	13,601,740	1,759,589
Capital Contributions			
Capital Contributions from Customers	(715,662)	(949,996)	234,334
Capital Contributions from subdivisions	(1,367,318)	(587,004)	(780,314)
Subdivision assets paid by developers; owned by NPEI after subdivision is energized	(1,131,509)		(1,131,509)
Total Capital Contributions	(3,214,489)	(1,537,000)	(1,677,489)
Net Fixed Asset Additions excluding Disposals	12,146,840	12,064,740	82,100

The 2017 distribution assets additions are projected at $12.8M, which is $2.1M higher than the 2017 budget amount of $10.8M. This variance is mainly due an increase in customer demand work of $1.3M and $1.1M of subdivision assets which have been installed and paid for by developers, with NPEI assuming ownership after the subdivision has been completed and energized. The cost of these subdivision assets is offset by an equal capital contribution of $1.1M. When NPEI assumes ownership of these assets, there is an increase to total fixed assets, but no impact to NPEI's cash position.

The Oakwood Drive capital project and the Kalar TS protection relay upgrade project that were originally budgeted in 2017 were not completed, and have been carried forward into the 2018 capital budget. Victoria Avenue Fly Road South Phase 1 overbuild of existing 3-phase line, which was budgeted for $309K, was not completed and will be a carry forward in the 2018 capital budget. Significant 2017 subdivision projects include Chippawa West, Cherryhill, Southgate estates, Centre Square condos, Smart Townes and Warren Woods. It is projected 534 lots will be connected in 2017.

Itron is the company that provides the intermediate communication service for data collection from the old style interval meters that we had deployed, which used the legacy 2G cellular communication technology. Itron provided notice in the spring of 2017 that they would no longer support the metering communication system due to it becoming obsolete in the cellular domain. This necessitated the meter change outs, in order to avoid possible communication disruptions to 212 meters in the field that provide energy metering for large commercial customers.

NPEI did experience a previous interruption to a significant number of these meters in the later part of 2016 which resulted in billing delays and significant additional effort to acquire the consumption data from the meters. All of the 2G meters are projected to be replaced by the end of 2017. Many of these meters still carried a net book value. As a result, NPEI recorded a Loss on Retirement of fixed assets in the amount of $102K in 2017.

Due to the replacement of the 2G meters, NPEI did not achieve its target of MIST meter replacements in 2017. The 2018 budget has included an additional 300 MIST meters to be replace to ensure NPEI's completion will be achieved by the end of 2020.

Capital contributions for 2017 are projected at $1.5M which excludes the subdivision assets paid by developers, owned by NPEI after the subdivision is energized, which is comparable to the 2017 budget of $1.5M. The majority of the capital contributions were related to the subdivision developments.

Building expenditures are projected at $357K, which includes the new Wi-max tower in Niagara Falls and the costs related to the schematic drawings and design of a new garage and truck washing facility. Computer hardware additions are projected at $403K, which includes 2 new nodes for the hyper-convergence (virtual environment conversion), network switches and 2 replacement plotters for engineering. Computer software additions are projected at $729K, and include Outage Management System upgrades for call taker and a mobile component, upgrade to the outage map, 2 GIS licenses, upgrade of Great

Plains, enhancements to the CIS for change of contacts, Class A and security upgrades for scan of documents for viruses.

Vehicles < 3 tonnes are projected at $177K, which includes the replacement of 3 pick-up trucks and 2 electric vehicles. Vehicles > 3 tonnes are projected at $697K, and includes the replacement of a single bucket truck and the 1989 Crane. Tools and Equipment are projected at $95K.

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 2017 is projected at $32K, which includes the design and construction of a new communications tower in Niagara Falls. The 2017 budget for Communications Equipment was $119K. NPEI had the engineering resources available to complete the entire Niagara Falls tower project in 2017. The cost of the tower is recorded in Building expenditures.

Liabilities and Share Holders Equity 2017

Current liabilities are projected to be $30.7M at the end of 2017. This is a decrease of $1.4M or 4%. The December 2017 power bill payable is projected to be $2.1M lower than the December 2016 power bill. Due to the Ontario Fair Hydro Plan, the credits related to the decreased time of use rates are included on NPEI's power bill, thereby lowering the monthly power bill liability.

Non-current liabilities are projected to be comparable to 2016. There was no new long term debt procured in 2017. However, NPEI had a loan carrying a fixed interest rate of 2.80% which came due in June of 2017. 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 2.81% with only interest repayments.

Capital contributions are projected to be $2.6M higher in 2017. See the table provided above.

Regulatory Liabilities are projected to be $1.3M lower in 2017 than 2016. Effective May 1, 2015 NPEI had a rate rider for the disposition of Account 1576 which was related to the changing of the lives of fixed assets. This rate rider was effective for 2 years and finished

April 30, 2017. Effective May 1, 2016, NPEI added a new rate rider related to the Adjustment to the 2015 Interim Rates. The total rate rider was for $272K and will be in effective for 12 months, finishing April 30, 2017. This rate rider was related to the adjustment to NPEI's working capital allowance from 13% to 10.48% as a result of NPEI filing a lead/lag study with the Ontario Energy Board. Effective May 1, 2017, NPEI had a rate rider to collect Lost Revenues related to the CDM programs which ran from 2011 to 2014.

In 2017, NPEI paid a total dividend of $1.4M to its shareholders proportionate to the shares held.

2017 Projected Income Statement

Regulatory Net Income does not include the depreciation expense for the FMV bump of $1,044K. Projected 2017 regulatory net income after tax and net movement in regulatory balances is $2,982K which is $98K greater than budget and $2.2M less than 2016.

The Gross profit is projected at $196K greater than budget and $613K greater than 2016. Effective May 1, 2016 for a period of twelve months, NPEI had a rate rider for the Adjustment to the 2015 Interim Rates related to the change in working capital allowance from 13% to 10.48%. This rate rider was a repayment to the customer and was included as negative revenue in the amount of $182k in 2016 and $50K in 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 2017, NPEI's residential fixed service charge moved from 68.7% to 79.19%.

Other revenue in 2017 is less than 2016 by $358K. In 2016, other revenue included $114K of labour recoveries billed to the Niagara Regional Wind Corp for the wind project. In 2017, disconnections for non-payment of residential customers during the winter months was introduced by the provincial government. As a result, NPEI's other revenue for collections and reconnections is projected to be $127K less than 2016. Finally, due to the 2G meters having to be retired earlier than their end of life, NPEI recorded a Loss on Retirement of fixed assets in the amount of $102K. Interest charges on overdue hydro accounts is $53K less than budget and $46K less than 2016, which is due to low income customers are exempt.

Cost of power is projected to decrease from 2016 by $20.3M or 12%. This decrease is due to the Ontario Fair Hydro Plan's initiative to reduce the time-of-use rates for electricity in order to achieve up to 25% savings on customer's monthly hydro bills. The Ontario Fair Hydro Plan credits are received on NPEI's monthly power bill.

Total expenses including depreciation are projected at $25,934K which is $61K over budget and $1,128K over 2016. Total operation, maintenance, utilization, billing & collecting and general administration expenses for 2017 are projected at $17,946K which is $232K over budget and $687K over 2016.

Of the $232K variance to budget there was civil work for maintenance of underground conductors and conduit that was not budgeted for and there were higher fleet repairs and replacement parts required to maintain NPEI's vehicles. Programming expenses exceeded budget due to the increased software purchases. Meter reading expenses were budgeted to decrease from 2016 as the MIST meter installations occurred. Due to the 2G meters taking priority due to lack of vendor support, the MIST meter replacements did not meet the 2017 target. Legal fees and property taxes in 2017 were less than budget thereby offsetting the maintenance operations increases.

In 2016, the Ontario Energy Board announced that all LDC's are to eliminate long term load transfers. This occurs when a customer may reside in the geographical area of one LDC but are physically supplied electricity by another LDC. NPEI has long term load transfers with CNP, Welland Hydro, Niagara-on-the-lake Hydro, Alectra Utilities, Grimsby Power and Hydro One. All LTLT applications will be filed by NPEI with the OEB by the end of 2017. For the five LTLT applications completed there were 20 customers transferring to NPEI and 50 customers transferring to the other LDC's. NPEI submitted joint applications with five of the above named LDC's and an independent application for the Hydro One customers. Only the Hydro One LTLT application will be outstanding at the end of 2017.

The Billing department held two customer engagement meetings related to Global Adjustment Class A. At the onset, there were 35 potential customers who were eligible for Class A. The meetings were held by NPEI's billing department and CDM department and encompassed presentations by the IESO and 2 engineering consulting firms. NPEI's billing staff worked with many of the 16 customers who accepted GA Class A by assisting them with the application and the on-line forms. Billing also had many changes to implement as a result of the Ontario Fair Hydro Plan and they are currently involved in the consultations for net metering and the change in bill presentment.

Due to the level of expenses related to postage, NPEI commenced a six-month e-bill contest in August 2017. The premise of the six-month period was to change a customer's preference and reliance on a hard copy bill to an electronically emailed notification that their bill was ready under "My Account". As at October 31, 2017, approximately 500 new e-bill customers were registered.

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 will be pursuing sending accounts in arrears that do not enroll in the Arrears Management Program ("AMP") and/or may have defaulted in the AMP to an outside collections agency.

The office hours for customers to visit NPEI's corporate office were changed to 4:00 pm in early 2017 due to safety issues. NPEI's customer service representatives continue to answer the phones and assist customers until 4:30 pm.

NPEI engaged in a project to review its hardware related to call flow for afterhours. NPEI also visited 2 after hours answering service providers. NPEI decided it was more cost efficient to remain with its current answering service provider. The customer service representatives also participated in a 2-part customer service development training program. "Here to help flyers" and the Smart Check Ad campaign ran through 2017 as part of customer engagement and education.

There were four retirements in 2017 and one union personnel resignation. As a result, restructuring and recruiting activities kept the human resources department extremely busy. NPEI hired a Business Analyst and an IT systems analyst in the last quarter of 2017. NPEI continued its investment into its most valued resource, strengthening its employee's skills in the areas of safety and leadership. There were seven apprentices that attended the Powerline Apprenticeship Program at various levels. Lead hand Supervisory training took place for all of NPEI's lead hands. First aid, CPR, working at heights and utility work protection code training were completed in 2017. Eight of NPEI's management staff completed the leadership training program and four completed the coaching program.

In 2017, Canada celebrated its 150th anniversary. NPEI sponsored each of its shareholders for various events related to Canada's 150th.

The 2017 projected expenses excluding depreciation are $687K higher than 2016. Labour expenses account for $444K which is a 4.18% increase in 2017 over 2016. Extended sick leave time taken by NPEI employees was less in 2017 than the prior year. Tree trimming was $79K higher in 2017 due to the five-year cyclical nature of the areas required to be maintained. Fleet vehicle repairs and replacement part purchases were higher than 2016 by $41K. Programming expenses and postage were higher by $52K and $14K respectively, in 2017, due to increased software license purchases, and NPEI issued a mailing to all customers regarding the change in office hours. Training programs were completed at a higher level in 2017 than the prior year.

2018 Budget Balance Sheet

Total Assets are budgeted at $221M which is $0.5M higher than 2017 projected total assets. Capital additions of fixed assets in 2018 total $13.3M, which exclude capital contributions of $2.1M. Intangible asset additions total $0.4M.

Cash has decreased by $4.6M which is due to the 2018 capital investment, principle repayment of existing loans in the amount of $1.5M and the net repayment of regulatory liabilities in the amount of $2.7M.

Effective May 1, 2018, 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, 2016 for the retail settlement variances (power, global adjustment, wholesale market, network and connection variances) in the amount of $5.4M.

NPEI has a five-year loan with TD bank which comes due December 3rd 2018. NPEI intends to refinance this loan in 2018 through the request for proposal process. NPEI does not intend to obtain any additional debt in 2018.

NPEI included a dividend payment of $1.4M in the 2018 budget.

Capital Additions 2018

Total fixed asset additions for 2018, net of vehicle disposals of $349K, are budgeted at $13.259M plus software additions of $0.369M for a total of $13.628M. Capital contributions are budgeted at $2.135M, for a net capital budget of $11.492M.

Gross capital additions related to the distribution system are budgeted at $11.282M, less capital contributions of $2.135M which include $752K of lot rebates, for net total distribution system additions of $9.147M.

As in previous years, NPEI's 2018 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 2018 Capital Projects. Two capital projects: Oakwood Drive Overhead Replacement, and the Kalar TS protective relay upgrade are projects that were originally scheduled to be completed in 2017. Due to the magnitude of customer demand and subdivision projects in 2017, and NPEI's resources, these two projects were deferred until 2018.

APPENDIX B
List of Projects

Item	Project	Gross Capital Investment	Capital Contribution	Net Capital Investment
1	Greenlane at Ontario Tie	160,194		160,194
2	Range Rd 2 East of Allen	120,655		120,655
3	Willoughby Rd Extension	280,737		280,737
4	Thorold Stone (Kalar -Montrose)	457,676		457,676
5	Switchgear	257,493		257,493
6	Station 14 Elim Ph II	971,639		971,639
7	Subdivision Rehabilitation Allowance	361,965		361,965
8	Additional sectionalizing switches	76,750		76,750
9	Victoria Avenue Fly Road South PH 1-Carryover from 2017	401,629		401,629
10	Victoria Ave. 7th Ave Phase 2	558,441		558,441
11	Reclosers	53,900		53,900
12	KALAR TS NSD570	200,000		200,000
13	Chippawa River Crossing	400,396		400,396
14	Portage Mountain Churchs Lane	383,291		383,291
15	Oakwood 111-25 to 98-7	648,476		648,476
16	Line Relocations due to Municipal Road Improvements	520,813	(260,000)	260,813
17	Replacement of Poles identified with Structural Integrity	624,352		624,352
18	Kiosk replacement program	100,407		100,407
19	System Sustainment allowance	869,500		869,500
20	Subdivision Lot servicing of existing lots	417,000	(417,000)	0
21	Connection and energizing of new subdivisions	482,004	(482,004)	0
22	Customer Demand Work	1,269,425	(728,000)	541,425
23	Metering - General	255,000		255,000
24	Metering - MIST	410,000		410,000
		10,281,743	**(1,887,004)**	**8,394,739**

Detailed descriptions of these capital projects can be found in the 2018 Capital projects section. See Appendix B.

NPEI will host customer engagement meetings for the Station 14 Voltage conversion project, the subdivision rehabilitation project, and the Chippawa River Crossing project. 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 2018 budget for Other Capital Additions reflects the considerations of customer focus, encouraging operational effectiveness and responding to public policy.

Expenditures proposed in 2018 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 enable NPEI to maintain a modern and reliable fleet, which improves efficiency, safety and reliability during the construction of capital projects.

The 2018 budget for hardware and software provides for the management of cyber risk through increasing digital technological advancements and growth of electronic files stored on various servers.

Building

In 2018, NPEI has budgeted $1,435K for building expenditures, $35K for the replacement of rooftop heating/air conditioning units. 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 (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 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 late spring of 2018 and be completed in 2019. 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 is a 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. By installing a new automated washing facility, NPEI will:

- conserve significant amounts of water through recycling
- harvest rain water to supplement our water utilization
- reduce the costs associated with the current manual washing process
- reduce safety hazards in the parking garage

General Equipment

In 2018, NPEI has budgeted $11K for general equipment, and $8K for ergonomic office equipment, $5K for 2 new defibrillators, and the replacement of NPEI's (2006) mail machine inserter for $60K. See Appendix C.

Hardware and Software

The Information Technology capital expenditures for 2018 continue to ensure that business goals are aligned to technological solutions. NPEI's network infrastructure will be optimized allowing for improved business uptime and resiliency, and a step towards becoming a network integrator between NPEI and its customers.

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 security
- Embedded business continuity practices, and continued update and testing of a Disaster Recovery Plan.

Hardware

The 2018 budgeted expenditures of $291K are related to the following projects/business needs:

- Virtual environment conversion from VM ware (Virtual Machine) to a hyper convergence model, to provide for growth and expanded contingency planning. At its capacity, data vulnerabilities are found in recovery and growth. Hyper convergence is storage in a server which includes all backup, disaster recovery, data movement and data efficiency. Each node is budgeted at $84K for a total of $169K in 2018, and allows for the replacement of 20 existing servers, which would carry a capital investment of over $200K.

- Replacement of NPEI's bill printer as a result of the consultation regarding the new bill presentment and dynamic messaging. The bill printer is budgeted at $50K. For additional details, see Appendix D.

Software

Software required for business process improvement projects and new requirements, which promote efficiency and reliability, has been budgeted at $0.369M. Software requirements include the following:

- Work Management / Outage Management System (OMS) upgrade to improve workflow efficiency and validation between the CIS system and call taker/work-ticket during a power outage for $75K.
- Service Location Request / SPOT replacement (replacement of a legacy outgrown system providing for both operational efficiencies and customer engagement; upfront capital investment with annual maintenance to follow.) The legacy product was in place for more than 10 years and has reached a point where other newer subsystems and technologies cannot integrate with it; PCs cannot be updated while legacy application is on the desktop $67K.
- Interactive employee forms, workflow and tracking – upfront capital investment to encourage operational efficiency, leading to improved workflow, documentation and reporting $36K
- Harris Northstar automation platform and bill presentment (regulatory requirements when there is provincial change or mandate.) $176K.

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.

The 2018 Information Technology focus is technology advancement encouraging business process improvement, efficiency, as well as, positioning NPEI for growth in data, as well as, business continuity and disaster recovery and planning. NPEI's technology infrastructure has matured and grown with the business. NPEI, in 2018, will take on technological advancements that previously we would not be able to explore the efficiencies. Over the past 5 years, NPEI has learned how the virtual environment can provide for growth as well as protection. Using this knowledge, NPEI has designed and planned for a virtual environment that will allow for data growth and vulnerability assessment to be met. This infrastructure is a change, as seen in the upfront investment in hardware, as well as, resource time to place us in a stream ready to address future growth and vulnerabilities. The Ontario Energy Board has challenged LDCs with being prepared for regulatory change, as well as, protection from cyber security. The 2018 budget line items within IT places NPEI in a position to address challenges directly, while meeting technology goals, focused on both the business units, and our customer.

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 D and E for details related to the hardware and software budgets.

Vehicles

NPEI has budgeted $343K for vehicles in 2018. This includes the replacement of a pick-up truck and a metering van for $85K combined. NPEI will replace the 2002 underground cable pulling machine for $223K. NPEI's current machine is fully depreciated and at the end of its useful life due to wear and tear. The 2002 machine has been included in the vehicle disposal amount of $349K. See Appendix F for details.

Tools and Equipment for Vehicles

Tools and equipment in the amount of $61K 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 within the Lincoln/West Lincoln service territory, 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.

2018 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

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 2018 Distribution Revenue is based on the 2018 IRM rate application that was submitted to the OEB in October 2017.

As part of the Renewed Regulatory Framework in Electricity, the OEB indicated that the revenue decoupling consultation would move forward.

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 Cost of Service rate application included distribution revenue split for the Residential rate class of 58% Fixed, 42% Variable. Phase 1 effective from May 1, 2016 to April 30, 2017 included a Residential rate class split of 68.5% Fixed and 31.5% variable. Phase 2, effective from May 1, 2017 to April 30, 2018 includes a Residential rate class split of 79.1% fixed service charge revenue and 20.9% volumetric distribution revenue. Effective May 1, 2019, NPEI's residential rate class distribution revenue will be 100% fixed.

Cost of Power

Cost of power is budgeted at $139M in 2018 which is $6.1M lower than the 2017 projected and $26M lower than 2016. This is due to the Ontario Fair Hydro Plan that was introduced in July 2017, which lowered the time of use rates for customers as part of the plan to reduce hydro bills by 25%. As a result, NPEI's calculates on a monthly basis the difference between the actual cost of power and the current time-of-use rates and submits this information to the IESO in order to receive the Ontario Fair Hydro Plan consumer discount on its power bill.

Other Revenue

Other revenue is budgeted at $1.1M which is equal to the projected 2017 and lower than 2016 by $328K. In 2016 NPEI received labour recoveries from the Niagara Regional Wind Corp. project. Collection and reconnection charges are budgeted $145K lower than 2016 due to new legislation prohibiting LDC's disconnecting customers for non-payment between November 15th and April 30th.

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 $18,004 excluding interest expense and depreciation are reflected in the 2018 budget. The projected 2017 OM&A expenses total $17,946K and 2016 OM&A expenses total $17,259K. The 2018 OM&A expenses are budgeted at $59K higher than the 2017 projected and $745K higher than 2016.

The total increase of $745K or 4.3% consists mainly of a labour increase of $698K. The labour increase consists of the 2% wage increase of $172K, payroll overhead burden increase of $139K, a second union position for the control room, replacement of a Customer Service representative, a Distribution Engineering Manager, a Business Analyst, an IT specialist, a Communications Coordinator and 2 apprentices.

Other distribution expenses excluding labour are budgeted to decrease by $195K from 2017 projected and $48K higher than 2016.

Interest Expense

Interest expense is budgeted at $2.7M in 2018. No new financing is anticipated at the time this budget has been prepared. Interest expense is lower than the projected 2017 amount of $47K. Finance income is budgeted in 2018 equal to the projected 2017.

Depreciation Expense

Depreciation expense excluding the depreciation on FMV adjustment of fixed assets is budgeted at $7.5M which is $534K higher than projected 2017 depreciation expense and $1,015K higher than 2016. 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 2018 depreciation expense. This increased depreciation will be high in both 2019 and 2020. The remaining increase is a result of the 2017 additions of $13M where the half year rule applies for depreciation calculation.

Wages and Benefits

NPEI's current collective agreement expires March 31, 2019. The 2018 budgeted wages include a 2% increase and an increase of 2% to the current payroll overhead burden.

There were 4 retirements in 2017 and one union resignation. There are no budgeted retirements in 2018.

One IT specialist was hired at the end of 2017. This position related to fulfilling system hardware requirements, a business analyst was budgeted to be hired in 2017 but due to difficulties in hiring this position, NPEI has included the Business Analyst in the 2018 budget. As part of succession planning an Engineering Manager is budgeted in 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 a second union position to aid with the additional work load.

MIST meters---(Metering Inside Settlement Timeframe)

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 has included $43K in 2018 related to MIST meter reading costs included in the Net movement in regulatory balances line on the Income statement.

Net Income After Taxes

Net income after taxes is budgeted at $1.9M which is $52K lower than the projected 2017 net income after taxes and $2.2M lower than 2016.

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 2018 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 recommends approval as follows:

1. The 2018 Capital budget of $11,492,000 be approved. This is comprised of capital additions, $11,282,000 offset by capital contributions in the amount of $2,135,000 for net distribution additions totaling $9,147,000, general plant and equipment, including the building and net of disposals of $1,976,000. Also the 2018 Intangible asset budgeted additions of $369,000 be approved.

2. The 2018 total operating expenditures in the amount of $26,546,000 including depreciation and depreciation related to the fair market value bump are approved.

Niagara Peninsula Energy
Financial Ratios
2015 to 2018

	2018 Budget	2017 Projected	2016 Actual	2015 Actual
EBITDA % (Earnings Before Income Tax, Depreciation & Amortization	41.78%	41.11%	44.03%	48.08%
Return on assets	1.33%	1.35%	2.24%	2.56%
F/S Return on Equity	3.22%	3.27%	5.69%	6.06%
Liquidity ratio	2.17	1.61	1.80	1.88
Ratio Debt/Total Assets	0.59	0.59	0.61	0.58
Debt/Equity Ratio	1.42	1.42	1.54	1.37

Niagara Peninsula Energy
Projected Balance Sheet
As at December 31, 2017
(000's)

	Projected 2017	Actual 2016	$ Variance	% Variance
ASSETS				
Current Assets				
Cash	20,140	21,564	(1,423)	-7%
Accounts Receivable	11,039	14,704	(3,666)	-25%
Unbilled Revenue	15,044	17,221	(2,177)	-13%
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	0	3	(3)	-100%
Payments in lieu of corporate taxes refundable	628	1,758	(1,130)	-64%
Inventories	1,429	1,365	64	5%
Prepaid Expenses	1,109	1,111	(3)	0%
	49,388	**57,729**	**(8,341)**	**-14%**
Fixed Assets				
Land	1,231	1,231	0	0%
Buildings	17,956	17,484	472	3%
Distribution Stations	9,572	9,383	189	2%
Transformer Station	6,672	6,576	97	1%
Distribution lines				
Overhead	121,047	115,727	5,320	5%
Underground	110,275	106,298	3,977	4%
Distribution transformers	46,835	45,436	1,400	3%
Distribution meters	11,920	11,171	749	7%
Trucks and Equipment	20,295	19,272	1,023	5%
	345,802	332,576	13,226	4%
Less: Accumulated Depreciation Buildings	(4,058)	(3,759)	(299)	8%
Less: Accumulated Depreciation Distribution Stations	(5,930)	(5,785)	(145)	3%
Less: Accumulated Depreciation Transformer Stations	(2,043)	(1,878)	(165)	9%
Less: Accumulated Depreciation Overhead	(61,546)	(59,657)	(1,889)	3%
Less: Accumulated Depreciation Underground	(58,311)	(55,944)	(2,367)	4%
Less: Accumulated Depreciation Distribution Transformers	(26,474)	(25,734)	(740)	3%
Less: Accumulated Depreciation Distribution Meters	(5,081)	(4,489)	(592)	13%
Less : Accumulated Depreciation Trucks and Equipment	(12,399)	(11,660)	(739)	6%
Less: Accumulated Depreciation	(175,840)	(168,905)	(6,935)	4%
	169,962	**163,671**	**6,291**	**4%**
Intangible Assets				
Land rights	1,732	1,732	0	0%
Computer Software	4,483	3,755	729	19%
Total Intangible Assets	6,215	5,487	729	13%
Less: Accumulated Depreciation intangible assets	(4,746)	(4,362)	(384)	9%
	1,469	**1,125**	**344**	31%
Deferred tax asset	**53**	**53**	**-**	**-**
Total non-current assets	**171,484**	**164,849**	**6,635**	4%
Total assets and regulatory balances	**220,872**	**222,578**	**(1,706)**	**-1%**

Niagara Peninsula Energy
Projected Balance Sheet
As at December 31, 2017
(000's)

	Projected 2017	Actual 2016	$ Variance	% Variance
LIABILITIES				
Current Liabilities				
Accounts Payable	7,758	6,109	1,649	27%
Power bill payable	10,177	12,328	(2,151)	-17%
Taxes Payable	0	0	0	100%
Deferred OPA revenue & standard offer	217	714	(497)	-70%
Customer Deposits	1,075	1,543	(468)	-30%
Current Portion of long term debt	11,514	11,466	48	0%
Total current liabilities	**30,742**	**32,160**	**(1,419)**	**-4%**
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	41,461	42,975	(1,514)	-4%
Employee Sick Leave Liability	56	55	1	1%
Employee Future Benefits	2,834	2,619	215	8%
Deferred Capital Contributions	34,719	32,086	2,633	8%
Amortization capital contributions	(9,028)	(8,202)	(826)	10%
Total non-current liabilities	**95,648**	**95,139**	**509**	**1%**
Total liabilities	**126,390**	**127,299**	**(910)**	**-1%**
Shares				
Share Capital	31,246	31,246	0	0%
Contributed Surplus	25,459	25,459	0	0%
Retained Earnings	34,400	33,862	538	2%
	91,105	**90,567**	**538**	**1%**
TOTAL LIABILITIES & EQUITY	**217,495**	**217,866**	**(372)**	**0%**
Regulatory Liabilities				
Retail Cost Variances	(314)	(223)	(90)	40%
Retail Settlement Variances	6,660	6,593	67	1%
Low Voltage Variances	(1,918)	(1,282)	(637)	50%
Stranded Meters	25	(204)	228	-112%
Other Regulatory Assets	1,433	1,500	(67)	-4%
Mist Meter Variance	92	84	8	10%
Smart Metering Entity Variance	50	42	8	20%
Regulatory related to income taxes	(2,735)	(2,735)	0	0%
Accounting Changes under GAAP (depreciation)	175	1,270	(1,095)	100%
Deferral & Variance Recovery 2014 application	207	193	13	7%
Deferral & Variance Recovery 2015 COS application	(118)	(119)	1	-1%
Deferral & Variance Adjust 2015 Interim rates	18	89	(70)	-79%
Lost revenue adjustment mechanism	(196)	(495)	299	-60%
	3,378	**4,712**	**(1,334)**	**-28%**
Total liabilities, equity and regulatory liabilities	**220,872**	**222,578**	**(1,706)**	**-1%**

Niagara Peninsula Energy
Projected Statement of Operations vs Budget
For the year ending December 31, 2017
(000's)

	Projected 2017	Budget 2017	Projected vs Budget $ Variance	Projected vs Budget % Variance	Actual 2016	Projected 2017 vs Actual 2016 $ Variance	Projected 2017 vs Actual 2016 % Variance
SERVICE REVENUE							
Standard Supply Service	124,665	144,101	(19,436)	-13%	141,649	(16,984)	-12%
Wholesale, Network & Connection Charges	20,668	25,787	(5,119)	-20%	24,020	(3,351)	-14%
Service Charge	17,818	16,987	831	5%	15,096	2,721	18%
Distribution Volumetric Charge	11,438	11,772	(334)	-3%	13,279	(1,840)	-14%
Standard Supply Service Admin Charge	156	156	(0)	0%	149	7	5%
Retailer Revenue	31	35	(4)	-11%	35	(4)	-12%
Other Revenue	1,114	1,390	(276)	-20%	1,472	(358)	-24%
Capital Contributions	826	847	(21)	-3%	738	88	12%
	176,717	201,076	(24,359)	-12%	196,439	(19,723)	-10%
Cost of Power							
Power Purchased	145,333	169,888	24,554	14%	165,669	20,336	12%
Total Cost of Power	145,333	169,888	24,554	14%	165,669	20,336	12%
Gross Profit Before Other Revenue	31,383	31,188	196	1%	30,770	613	2%
Expenses							
Operation and maintenance							
Distribution	7,102	6,694	(408)	-6%	6,495	(607)	-9%
Utilization	262	264	3	1%	219	(42)	-19%
Billing & Collecting	5,528	5,530	2	0%	5,340	(188)	-4%
Administration & general	5,054	5,226	172	3%	5,205	151	3%
Depreciation	6,944	7,080	136	2%	6,462	(481)	-7%
Depreciation on FMV adjustment of fixed assets	1,044	1,078	34	100%	1,085	41	4%
TOTAL EXPENSES	25,934	25,872	(61)	0%	24,806	(1,128)	-5%
Income from operating activities	**5,450**	**5,316**	**134**	**3%**	**5,965**	**(515)**	**-9%**
Finance income	210	192	(18)	-10%	108	102	95%
Finance costs	(2,725)	(2,727)	(2)	0%	(2,428)	298	-12%
Income before income taxes	**2,935**	**2,780**	**118**	**4%**	**3,645**	**(710)**	**-19%**
Income tax expense	(1,075)	(1,030)	45	-4%	(238)	(837)	352%
Net Income for the year	**1,860**	**1,751**	**73**	**4%**	**3,407**	**(1,547)**	**-45%**
Net movement in regulatory balances, net of tax	78	55	(23)	-42%	666	(588)	-88%
Net income for the year, net movement in regulatory balances and comprehensive income	**1,938**	**1,806**	**132**	**7%**	**4,073**	**(2,135)**	**-52%**

Statistics

	Projected 2017	Budget 2017	Projected vs Budget	Actual 2016	Projected 2017 vs Actual 2016
Cost of Power %	82.24%	84.49%	2.25 pts	84.34%	2.10 pts
Gross Profit % After Other Revenue	17.76%	15.51%	2.25 pts	15.66%	2.10 pts
Total Expenses as % of Total Revenue	14.68%	12.87%	(1.81) pts	12.63%	(2.05) pts
Net Income After Tax as % of Total Revenue	1.10%	0.90%	0.20 pts	2.07%	(0.98) pts
Income Tax % of Net Income	36.63%	37.04%	(0.41) pts	6.53%	30.10 pts
Other Revenue	0.63%	0.69%	(0.06) pts	0.75%	(0.12) pts
Distribution	4.02%	3.33%	(0.69) pts	3.31%	(0.71) pts
Utilization	0.15%	0.13%	(0.02) pts	0.11%	(0.04) pts
Billing & Collecting	3.13%	2.75%	(0.38) pts	2.72%	(0.41) pts
Administration & general	2.86%	2.60%	(0.26) pts	2.65%	(0.21) pts
Depreciation	3.93%	3.52%	(0.41) pts	3.29%	(0.64) pts
Net finance costs	1.42%	1.26%	(0.16) pts	1.18%	(0.24) pts

**Niagara Peninsula Energy Inc.
Statement of Retained Earnings
for the year ending December 31, 2017
(000's)**

	Projected 2017	Actual 2016
Retained Earnings, Beginning of Year	33,862	31,189
Net Income	1,938	4,073
Dividends on common shares	(1,400)	(1,400)
Retained Earnings, End of Period	**34,400**	**33,862**

Niagara Peninsula Energy Inc.
Statement of Cash Flows
For the year ending December 31, 2017

	Projected 2017 $	Actual 2016 $
Cash Provided By (Used In):		
Operations		
Net income and net movement in regulatory balances	1,938	4,073
Adjustments for:		
Depreciation and amortization	5,891	6,232
Depreciation and amortization intangible assets	384	230
Depreciation expense on fair market value adjustment of fixed assets	1,044	1,085
Amortization of deferred revenue	(826)	(738)
Contributions received from customers	2,633	4,031
Net loss on disposal of property, plant and equipment	96	8
Post-employment benefits	215	115
Interest expense	2,515	2,319
Employee's accumulated vested sick leave	1	3
Deferred tax expense	0	427
Current tax expense	1,075	(189)
	14,966	17,597
Changes in non-cash working capital components		
Accounts receivable	3,666	(98)
Due to/from related parties	6	(13)
Unbilled revenue	2,177	163
Materials and supplies	(64)	134
Prepaid expenses	3	1
Accounts payable and accrued liabilities	(502)	(1,199)
Customer deposits	(468)	10
Deferred revenue	(497)	(117)
	19,287	16,478
Regulatory balances	(1,334)	(2,134)
Income tax paid	(1,017)	(1,291)
Income tax received	1,072	28
Interest paid	(2,725)	(2,428)
Interest received	210	108
Net cash from operating activities	15,493	10,762
Investing activities		
Purchase of property, plant and equipment	(13,322)	(15,084)
Purchase of intangible assets	(729)	(342)
Net cash used by investing activities	**(14,050)**	**(15,426)**
Financing activities		
Dividends paid	(1,400)	(1,400)
Proceeds from long-term debt	0	20,000
Repayment of long-term debt	(1,466)	(1,420)
Net cash from financing activities	**(2,866)**	**17,180**
Change in cash and cash equivalents	(1,423)	12,515
Cash and cash equivalents, beginning of year	21,564	9,049
Cash and cash equivalents, end of year	20,140	21,564

Niagara Peninsula Energy
Projected Capital Budget
For the year ending December 31, 2017
(000's)

	Projected 2017	Original Budget 2017	Projected vs 2017 Budget Variance	Actual 2016	Projected 2017 vs 2016 Variance	2015 Test Year Approved in Rate App
Land and Land Rights	0	0	0	0	0	0
Buildings & Fixtures	357	374	17	53	(304)	87
Sub Total	357	374	17	53	(304)	87
Distribution Station	188	200	12	0	(188)	0
Transformer Station	97	400	303	0	(97)	0
Overhead Distribution	5,408	5,304	(104)	6,307	899	4,505
Underground Distribution	3,977	2,829	(1,148)	5,007	1,030	3,514
Distribution Transformers	1,663	1,422	(241)	1,508	(155)	1,547
Meters	735	435	(300)	331	(404)	285
Smart Meters/MIST Meters	200	200	0	159	(41)	143
Sub Total	12,267	10,789	(1,478)	13,311	1,044	9,994
Office Furniture & Equipment	23	20	(3)	28	5	33
Computer Equipment, Hardware	403	401	(1)	241	(161)	240
Vehicles < 3 tonnes	177	180	3	75	(102)	114
Vehicles > 3 tonnes	697	515	(182)	643	(55)	514
Vehicles transportation other	0	0	0	75	75	71
Stores Equipment	0	0	0	0	0	0
Tools, Shop & Garage Equipment	95	82	(13)	119	24	61
Measurement & Testing Equipment	0	0	0	0	0	1
Communication equipment	32	119	87	302	270	215
Miscellaneous equipment	0	0	0	0	0	1
Sub Total	1,428	1,317	(110)	1,482	55	1,250
Total Capital before capital contributions	**14,052**	**12,480**	**(1,571)**	**14,847**	**795**	**11,331**
Capital Contributions	(2,633)	(1,537)	1,096	(3,995)	(1,361)	(828)
Net property plant & equipment	11,419	10,943	(475)	10,852	(567)	10,503
Intangible assets						
Computer Software	729	1,121	392	342	(386)	369
Total Intangibles	729	1,121	392	342	(386)	369
Total Gross Capital Expenditures	**12,147**	**12,064**	**(83)**	**11,194**	**(953)**	**10,872**
Disposals	(826)	(381)	445	(496)	329	(314)
Net Captial Additions after disposals	**11,321**	**11,683**	**362**	**10,698**	**(623)**	**10,558**

Project	Projected 2017 Investment	2017 Budget	2017 Budget Variance
Dorchester - McLeod to Dunn Phase 2	219,414	359,131	(139,717)
Oakwood Drive - Overhead replacement -deferred from 2016	11,512	600,819	(589,307)
Padmount Switchgear replacement program	221,369	250,000	(28,631)
Station #14 Voltage Conversion Phase I	579,849	589,623	(9,774)
Brown Road extension - Montrose to Blackburn	76,681	189,664	(112,983)
Subdivision Rehabilitation Allowance	399,224	245,151	154,073
Additional sectionalizing switches	54,142	73,000	(18,858)
Victoria Avenue Fly Road South PH 1- deferred from 2016	308,108	308,719	(611)
1-Phase Hydraulic Reclosure Upgrades	48,881	100,000	(51,119)
Jordan Road Voltage Conversion Phase IV	562,661	561,614	1,047
Downtown Core PILCDSTA De-commissioning	486,002	292,171	193,831
Dorchester Mountain to Riall - deferred from 2016	594,161	678,670	(84,509)
Lightning Mitigation Measures	-	30,000	(30,000)
NS&T Hwy OH Crossing	160,405	-	160,405
Chippawa Redundant Supply Upgrades Phase I	315,984	343,719	(27,735)
Heartland Road extension-Brown Road to Chippawa Creek	104,119	114,583	(10,463)
Station DS Power Transformer Replacement	187,883	200,000	(12,117)
Kalar TS Protection-Relay Upgrades	96,701	400,000	(303,299)
Line Relocations due to Municipal Road Improvements	241,514	500,000	(258,486)
Replacement of Poles identified with Structural Integrity	1,059,405	626,236	433,169
Kiosk replacement program	1,000,002	1,001,137	(1,136)
System Sustainment allowance	901,784	820,000	81,784
Subdivision Lot servicing of existing lots	818,784	275,000	543,784
Connection and energizing of new subdivisions	548,533	312,004	236,529
Subdivision Lot Rebates- new connections	581,400	250,000	331,400
Customer Demand Work	2,334,313	1,124,500	1,209,813
Metering - General and MIST	935,000	543,500	391,500
Total Distribution Assets	12,847,829	10,789,240	2,058,589
Building	357,000	373,000	(16,000)
Office furniture and equipment	23,000	20,000	3,000
Computer Hardware additions	403,000	401,390	1,610
Software additions	729,000	1,120,860	(391,860)
Fleet replacements excluding disposals and Tools	969,500	777,250	192,250
Wi-max communication-Niagara Falls Tower	32,000	120,000	(88,000)
Total General Plant & Equipment	2,513,500	2,812,500	(299,000)
Total Fixed Asset Additions	15,361,329	13,601,740	1,759,589
<u>Capital Contributions</u>			
Capital Contributions from Customers	(715,662)	(949,996)	234,334
Capital Contributions from subdivisions	(1,367,318)	(587,004)	(780,314)
Subdivision assets paid by developers; owned by NPEI after subdivision is energized	(1,131,509)		(1,131,509)
Total Capital Contributions	(3,214,489)	(1,537,000)	(1,677,489)
Net Fixed Asset Additions excluding Disposals	12,146,840	12,064,740	82,100

Niagara Peninsula Energy
Budget Balance Sheet
As at December 31, 2018
(000's)

	Budget 2018	Projected 2017	$ Variance	% Variance	Actual 2016	$ Variance	% Variance
ASSETS							
Current Assets							
Cash	15,542	20,140	(4,598)	-23%	21,564	(1,423)	-7%
Accounts Receivable	11,149	11,039	110	1%	14,704	(3,666)	-25%
Unbilled Revenue	15,194	15,044	150	1%	17,221	(2,177)	-13%
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	0	0	0	100%	3	(3)	-100%
Payments in lieu of corporate taxes refundable	328	628	(300)	-48%	1,758	(1,130)	-64%
Inventories	1,386	1,429	(43)	-3%	1,365	64	5%
Prepaid Expenses	1,164	1,109	55	5%	1,111	(3)	0%
	44,764	**49,388**	**(4,625)**	-9%	**57,729**	**(8,341)**	**-14%**
Fixed Assets							
Land and land rights	1,231	1,231	0	0%	1,231	0	0%
Buildings	19,391	17,956	1,435	8%	17,484	472	3%
Distribution Stations	9,572	9,572	0	0%	9,383	189	2%
Transformer Station	6,872	6,672	200	3%	6,576	97	1%
Distribution lines							
Overhead	126,594	121,047	5,548	5%	115,727	5,320	5%
Underground	113,939	110,275	3,664	3%	106,298	3,977	4%
Distribution transformers	47,840	46,835	1,005	2%	45,436	1,400	3%
Distribution meters	12,585	11,920	665	6%	11,171	749	7%
Trucks and Equipment	21,037	20,295	742	4%	19,272	1,023	5%
	359,061	345,802	13,259	4%	332,576	13,226	4%
Less: Accumulated Depreciation	(183,856)	(175,840)	(8,015)	5%	(168,905)	(6,935)	4%
	175,206	169,962	5,243	3%	163,671	6,291	4%
Intangible Assets							
Land rights	1,732	1,732	0	0%	1,732	0	0%
Computer Software	4,852	4,483	369	8%	3,755	729	19%
Total Intangible Assets	6,584	6,215	369	6%	5,487	729	13%
Less: Accumulated Depreciation intangible assets	(5,272)	(4,746)	(526)	11%	(4,362)	(384)	9%
	1,311	**1,469**	**(158)**	**-11%**	**1,125**	**344**	**31%**
Total non-current assets	**176,517**	**171,431**	**5,086**	**3%**	**164,796**	**6,635**	**4%**
Deferred tax asset	**53**	**53**	0	0%	**53**	0	0%
Total non-current assets	**176,570**	**171,484**	**5,086**	3%	**164,849**	**6,635**	**0.040248512**
Total assets and regulatory balances	**221,333**	**220,872**	**461**	**0%**	**222,578**	**(1,706)**	**-1%**

Niagara Peninsula Energy
Budget Balance Sheet
As at December 31, 2018
(000's)

	Budget 2018	Projected 2017	$ Variance	% Variance	Actual 2016	$ Variance	% Variance
LIABILITIES							
Current Liabilities							
Accounts Payable	7,913	7,758	155	2%	6,109	1,649	27%
Power bill payable	10,380	10,177	204	2%	12,328	(2,151)	-17%
Deferred OPA revenue & standard offer	228	217	11	5%	714	(497)	-70%
Customer Deposits	975	1,075	(100)	-9%	1,543	(468)	-30%
Current Portion of long term debt	1,124	11,514	(10,390)	-90%	11,466	48	0%
Total current liabilities	**20,621**	**30,742**	**(10,120)**	-33%	**32,160**	**(1,419)**	**-4%**
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	50,375	41,461	8,914	21%	42,975	(1,514)	-4%
Employee Sick Leave Liability	25	56	(31)	-55%	55	1	1%
Employee Future Benefits	2,984	2,834	150	5%	2,619	215	8%
Deferred Capital Contributions	36,854	34,719	2,135	6%	32,086	2,633	8%
Amortization capital contributions	(9,916)	(9,028)	(888)	10%	(8,202)	(826)	10%
Total non-current liabilities	**105,928**	**95,648**	**10,280**	11%	**95,139**	**509**	**1%**
Total liabilities	**126,549**	**126,390**	**159**	0%	**127,299**	**(910)**	**-1%**
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	34,885	34,400	486	1%	33,862	538	2%
	91,590	**91,105**	**486**	**1%**	**90,567**	**538**	**1%**
TOTAL LIABILITIES & EQUITY	**218,139**	**217,495**	**645**	**0%**	**217,866**	**(372)**	**0%**
Regulatory Liabilities							
Retail Cost Variances	(389)	(314)	(75)	24%	(223)	(90)	0%
Retail Settlement Variances	4,439	6,660	(2,221)	-33%	6,593	67	1%
Low Voltage Variances	(2,662)	(1,918)	(744)	39%	(1,282)	(637)	0%
Stranded Meters	25	25	0	0%	(204)	228	0%
Other Regulatory Assets	1,499	1,433	66	5%	1,500	(67)	0%
Mist Meter Variance	0	92	(92)	-100%	84	8	0%
Smart Metering Entity Variance	50	50	0	0%	42	8	20%
Regulatory related to income taxes	(2,735)	(2,735)	0	0%	(2,735)	0	0%
Accounting Changes under GAAP (depreciation)	175	175	0	0%	1,270	(1,095)	100%
Deferral & Variance Recovery 2014 application	207	207	0	0%	193	13	7%
Deferral & Variance Recovery 2015 COS applicatio	(118)	(118)	0	0%	(119)	1	-1%
Deferral & Variance Adjust 2015 Interim rates	18	18	0	0%	89	(70)	-79%
Deferral & Variance Adjust 2017 application	2,686	0	2,686	100%	0	0	100%
Lost revenue adjustment mechanism	0	(196)	196	-100%	(495)	299	0%
	3,194	**3,378**	**(184)**	-5%	**4,712**	**(1,334)**	-28%
Total liabilities, equity and regulatory liabilities	**221,333**	**220,872**	**461**	**0%**	**222,578**	**(1,706)**	**-1%**

Niagara Peninsula Energy Inc.
Budgeted Statements of Operations
For the year ending December 31, 2018
(000's)

	Budget 2018	Projected 2017	2018 vs 2017 $ Variance	2018 vs 2017 % Variance	Actual 2016	2018 vs 2016 $ Variance	2018 vs 2016 % Variance	Rate Application Test Year	Budget 2018 vs Test Year	
SERVICE REVENUE										
Standard Supply Service	118,882	124,665	(5,783)	-5%	141,649	(22,768)	-16%	120,621	(1,739)	-1.44%
Wholesale, Network & Connection Charges	20,327	20,668	(341)	-2%	24,020	(3,692)	-15%	23,529	(3,202)	-13.61%
Service Charge	19,930	17,818	2,112	12%	15,096	4,834	32%	14,897	5,033	33.79%
Distribution Volumetric Charge	9,636	11,438	(1,803)	-16%	13,279	(3,643)	-27%	13,901	(4,265)	-30.68%
Standard Supply Service Admin Charge	155	156	(1)	-1%	149	5	4%	147	8	5.55%
Retailer Revenue	32	31	1	2%	35	(3)	-10%	45	(14)	-30.68%
Other Revenue	1,144	1,114	30	3%	1,472	(328)	-22%	1,349	(205)	-15.22%
Capital Contributions	888	826	62	8%	738	150	20%	800	88	11.03%
	170,994	176,717	(5,723)	-3%	196,439	(25,446)	-13%	175,289	(4,296)	-2.45%
Cost of Power										
Power Purchased	139,209	145,333	6,124	4%	165,669	26,460	16%	144,150	4,940	3.43%
	139,209	145,333	6,124	4%	165,669	26,460	16%	144,150	4,940	3.43%
Gross Profit Before Other Revenue	**31,784**	**31,383**	**401**	**1%**	**30,770**	**1,014**	**3%**	**31,140**	**645**	**2.07%**
Expenses										
Operation and maintenance										
Distribution	6,796	7,102	306	4%	6,495	(302)	-5%	6,521	(275)	-4.22%
Utilization	209	262	52	20%	219	10	5%	169	(41)	-24.13%
Billing & Collecting	5,700	5,528	(172)	-3%	5,340	(360)	-7%	5,249	(451)	-8.60%
Administration & general	5,299	5,054	(245)	-5%	5,205	(94)	-2%	4,486	(812)	-18.11%
Depreciation	7,478	6,944	(534)	-8%	6,462	(1,015)	-16%	5,834	(1,644)	-28.17%
Depreciation on FMV adjustment of fixed a	1,064	1,044	(20)	-2%	1,085	21	2%	0	(1,064)	0.00%
TOTAL EXPENSES	**26,546**	**25,934**	**(613)**	**-2%**	**24,806**	**(1,740)**	**-7%**	**22,259**	**(4,287)**	**-19.26%**
Income from operating activities	**5,238**	**5,450**	**(212)**	**-4%**	**5,965**	**(726)**	**-12%**	**8,881**	(3,643)	-41.02%
Finance income	204	210	(6)	-3%	108	96	89%	100	104	104.00%
Finance costs	(2,678)	(2,725)	47	-2%	(2,428)	(250)	10%	(3,296)	619	-18.76%
Income before income taxes	**2,765**	**2,935**	**(171)**	**-6%**	**3,645**	**(881)**	**-24%**	**5,685**	**(2,920)**	**-51.37%**
Income tax expense	(1,063)	(1,075)	12	-1%	(238)	(825)	347%	(168)	**(895)**	532.33%
Net Income for the year	**1,701**	**1,860**	**(159)**	**-9%**	**3,407**	**(1,706)**	**-50%**	**5,516**	**(3,815)**	**-69.16%**
Net movement in regulatory balances, net of tax	184	78	106	136%	666	(482)	-72%	0	184	100.00%
Net income for the year, net movement in regulatory balances and comprehensive income	**1,886**	**1,938**	**(52)**	**-3%**	**4,073**	**(2,187)**	**-54%**	**5,516**	**(3,631)**	**-65.82%**
Other comprehensive income for the year	0	0	0	0%	0	0	0%	0	0	**0**
Total comprehensive income for the yea	**1,886**	**1,938**	**(52)**	**-3%**	**4,073**	**(2,187)**	**-54%**	**5,516**	**(3,631)**	**-65.82%**

Niagara Peninsula Energy Inc.
Statement of Retained Earnings
for the year ending December 31, 2018
(000's)

	Budget 2018	Projected 2017	Actual 2016
Retained Earnings, Beginning of Year	34,400	33,862	31,189
Net Income	1,886	1,938	4,073
Dividends on common shares	(1,400)	(1,400)	(1,400)
Retained Earnings, End of Period	**34,885**	**34,400**	**33,862**

Niagara Peninsula Energy Inc.
Statement of Cash Flows
For the year ending December 31, 2018

	Budget 2018 $	Projected 2017 $	Actual 2016 $
Cash Provided By (Used In):			
Operations			
Net income and net movement in regulatory balances	1,886	1,938	4,073
Adjustments for:			
Depreciation and amortization	6,951	5,891	6,232
Depreciation and amortization intangible assets	526	384	230
Depreciation expense on fair market value adjustment of fixed assets	1,064	1,044	1,085
Amortization of deferred revenue	(888)	(826)	(738)
Contributions received from customers	2,135	2,633	4,031
Net loss on disposal of property, plant and equipment	0	96	8
Employee future benefits	150	215	115
Interest expense	2,474	2,515	2,319
Employee's accumulated vested sick leave	(31)	1	3
Deferred tax expense	0	0	427
Current tax expense	1,063	1,075	(189)
	15,330	14,966	17,597
Changes in non-cash working capital components			
Accounts receivable	(110)	3,666	(98)
Due to/from related parties	0	6	(13)
Unbilled revenue	(150)	2,177	163
Materials and supplies	43	(64)	134
Prepaid expenses	(55)	3	1
Accounts payable and accrued liabilities	359	(502)	(1,199)
Customer deposits	(100)	(468)	10
Deferred revenue	11	(497)	(117)
	15,327	19,287	16,478
Regulatory balances	(184)	(1,334)	(2,134)
Income tax paid	(763)	(1,017)	(1,291)
Income tax received	0	1,072	28
Interest paid	(2,678)	(2,725)	(2,428)
Interest received	204	210	108
Net cash from operating activities	11,906	15,493	10,762
Investing activities			
Purchase of property, plant and equipment	(13,259)	(13,322)	(15,084)
Purchase of intangible assets	(369)	(729)	(342)
Net cash used by investing activities	**(13,627)**	**(14,050)**	**(15,426)**
Financing activities			
Dividends paid	(1,400)	(1,400)	(1,400)
Proceeds from long-term debt	0	0	20,000
Repayment of long-term debt	(1,476)	(1,466)	(1,420)
Net cash from financing activities	**(2,876)**	**(2,866)**	**17,180**
Change in cash and cash equivalents	(4,598)	(1,423)	12,515
Cash and cash equivalents, beginning of year	20,140	21,564	9,049
Cash and cash equivalents, end of year	**15,542**	**20,140**	**21,564**

Niagara Peninsula Energy Inc.
Capital Budget 2018
For the year ending December 31, 2018
(000's)

	Appendix	Proposed Budget 2018	Projected 2017	Proposed Budget 2016 vs Projected 2016 Variance	Actual 2016	Test Year Approved in Rate App	Variance to Rate Application
Land and Land Rights	A	0	0	0	0	0	0
Buildings & Fixtures	A	1,435	357	1,078	53	87	1,348
Sub Total		1,435	357	1,078	53	87	1,348
Distribution Station	B	0	188	(188)	0	0	0
Transformer Station	B	200	97	103	0	0	200
Overhead Distribution	B	5,548	5,408	140	6,307	4,505	1,042
Underground Distribution	B	3,664	3,977	(313)	5,007	3,514	150
Distribution Transformers	B	1,205	1,663	(458)	1,508	1,547	(342)
Meters	B	255	735	(480)	331	285	(30)
Smart Meters	B	410	200	210	159	143	267
Sub Total		11,282	12,267	(985)	13,311	9,994	1,287
Office Furniture & Equipment	C	81	23	58	28	33	48
Computer Equipment, Hardware	D	291	403	(112)	241	240	51
Vehicles < 3 tonnes	F	85	177	(92)	75	114	(29)
Vehicles > 3 tonnes	F	35	697	(662)	643	514	(479)
Vehicles Transportation Other	F	223	0	223	75	71	152
Stores Equipment		0	0	0	0	0	0
Tools, Shop & Garage Equipment	G	61	95	(34)	119	61	0
Measurement & Testing Equipment		0	0	0	0	1	(1)
Communication equipment	H	115	32	83	302	215	(100)
Miscellaneous equipment		0	0	0	0	1	(1)
Sub Total		891	1,428	(537)	1,482	1,250	(359)
Total Capital before capital contributions		**13,608**	**14,052**	**(444)**	**14,847**	**11,331**	2,277
Capital Contributions	B	(2,135)	(2,633)	498	(3,995)	(828)	(1,307)
Net property plant & equipment		11,473	11,419	54	10,852	10,503	970
Intangible assets							
Computer Software	E	369	729	(360)	342	369	(1)
Total Intangibles		369	729	(360)	342	369	(1)
Total Gross Capital Expenditures including Capital Contributions		**11,841**	**12,147**	**(306)**	**11,194**	**10,872**	970
Disposals including scrap transformers		(349)	(826)	477	(496)	(314)	(35)
Net Captial Additions after disposals		**11,492**	**11,321**	**171**	**10,698**	**10,558**	935

APPENDIX A

Building 2018

	2018 Budget
Building	
Replace Rooftop Heat/AC Units	35,000
Architect, Civil, Mechanical for Garage and Truck Washing Bay	1,400,000
Total	**1,435,000**

APPENDIX B
List of Projects

Item	Project	Gross Capital Investment	Capital Contribution	Net Capital Investment
1	Greenlane at Ontario Tie	160,194		160,194
2	Range Rd 2 East of Allen	120,655		120,655
3	Willoughby Rd Extension	280,737		280,737
4	Thorold Stone (Kalar -Montrose)	457,676		457,676
5	Switchgear	257,493		257,493
6	Station 14 Elim Ph II	971,639		971,639
7	Subdivision Rehabilitation Allowance	361,965		361,965
8	Additional sectionalizing switches	76,750		76,750
9	Victoria Avenue Fly Road South PH 1-Carryover from 2017	401,629		401,629
10	Victoria Ave. 7th Ave Phase 2	558,441		558,441
11	Reclosers	53,900		53,900
12	KALAR TS NSD570	200,000		200,000
13	Chippawa River Crossing	400,396		400,396
14	Portage Mountain Churchs Lane	383,291		383,291
15	Oakwood 111-25 to 98-7	648,476		648,476
16	Line Relocations due to Municipal Road Improvements	520,813	(260,000)	260,813
17	Replacement of Poles identified with Structural Integrity	624,352		624,352
18	Kiosk replacement program	100,407		100,407
19	System Sustainment allowance	869,500		869,500
20	Subdivision Lot servicing of existing lots	417,000	(417,000)	0
21	Connection and energizing of new subdivisions	482,004	(482,004)	0
22	Customer Demand Work	1,269,425	(728,000)	541,425
23	Metering - General	255,000		255,000
24	Metering - MIST	410,000		410,000
		10,281,743	**(1,887,004)**	**8,394,739**

Total Labour	4,394,252
Total Truck	1,029,725
Total Material	2,759,051
Total AP	2,098,714
Total before Contributions	10,281,743

PROPOSED N.P.E.I 2018 CAPITAL BUDGET PROGRAM

As in previous years, the NPEI 2018 Capital Budget will continue 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 cyclic 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.

Expansions and Reinforcement of the N.P.E.I. 13.8 K.V. / 27.6 K.V. Primary Distribution System to accommodate load growth & reliability requirements.

1. **Greenlane @ Ontario Underground Tie** **Investment Category SS**

   Project scope involves the installation of approximately 0.25 KM of 1000 MCM underground primary cable in a new concrete encased duct-bank to create a tie on the Beamsville 18-M-1 system between two primary lines on Ontario Street & Greenlane Rd. Benefits include increased Customer reliability during contingencies and capacity increase to the Beamsville downtown core.
   Estimated cost: $160,194.00 ***Project #2018-0001***

2. **Range Road 2--East of Allen Road** **Investment Category SS**

   Project scope involves extension of 0.66KM. of a rural overhead primary distribution line between pole #43518 & pole #43581 to replace 0.5KM of distribution line presently located on an opened road allowance with poor access. Install 13-new 40' wooden poles. The framing & stringing of this section of line will tie to a line within the Road Allowance of Range Road 2. System benefits include improved reliability an emergency response, with removal of inaccessible line upon completion.
   Estimated Cost= $ 120, 655.00 ***Project #2018-0003***

3. **Willoughby Rd Extension – Weinbrenner to Willick** **Investment Category SS**

   Project scope involves extension of 0.7KM. of a rural overhead primary distribution line along Willoughby Rd from Weinbrenner to Willick. This project builds on previous re-build work completed on Willoughby Rd starting in 2015 and is a continuation of the aim to reinforce supply to the Chippewa Area of Niagara Falls to support new growth. Includes installation of 11-new 45' wooden poles and approx. 240m of duct to traverse under the CNP right of way.
   Estimated Cost= $ 280,737.00 ***Project #2018-0005***

4. **Thorold Stone Rd-- Montrose to Kalar** **Investment Category SR**

   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= $ 457,676.00 ***Project #2018-0004***

5. Pad-mounted Switchgear Replacements **Investment Category SR**

The Underground Equipment Inspection Program has identified a requirement for replacement of air insulated pad-mounted switchgear units, with dead-front stainless steel enclosure SF-6 Gas Insulated Equipment, due to corrosion and contamination issues, which will continue at a rate of 3-Units per year. 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 = $257,493.00 ***Project #2018-0006***

6. Station #14--Voltage Conversion Phase II **Investment Category SR**

Rebuild Project which targets 1.20 kilometers of urban distribution line installed in 1956, including 83 pole changes, new three-phase (0.4KM @ 14 poles) new single phase (2.0KM @ 52 poles) & secondary (3.0KM @ 17 poles) circuits, 19-single phase distribution transformer replacements resulting in the upgraded supply to about 256 residential customers directly, in the area bounded by Drummond Rd, Skinner St, Dell Ave, Hawkins St, Arad St, Churchill St, Atlee St & Margaret St. System benefits include reconstruction to eliminate Municipal Sub-station 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: $ 971,639.00 ***Project #2018-0007***

7. Subdivision Rehabilitation Allowance. **Investment Category SR**

Establishment of this Capital Program provides 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. The original installations were duct-less, making replacement difficult and costly. To extend lifecycles of the infrastructure NPEI recently completed a Program to replace the Submersible Transformers with Pad-mount Transformers. The program began in 1994 with approximately 400 units converted. Sections of primary cable within the submersible enclosure, damaged by poor heat dissipation were spliced out and re-terminated, preventing failure. The cable was manufactured to a 133% insulation level, prolonging the life cycle, however, without a base value to compare the results of any cable testing, it is difficult to determine degradation since its installation. Expected lifespan of the cable is 35 years. To correct a noted deficiency in last Asset Assessment NPEI has entered installation dates, within the GIS, from as-built drawings, to help in prioritizing future replacement. The program would facilitate the installation, by directional boring methods, of a 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 under the Sustainment Budget. The first subdivision targeted was installed in 1967.

Estimated cost: $361,965.00 ***Project #2018-0009***

8. Additional Sectionalizing Switches—8-Units **Investment Category SS**

A review of existing feeder configurations, sourced by Stanley, Murray, Beamsville & Niagara West Transformer Stations, Kalar M.T.S. and Vineland D.S., utilizing system optimization software, has identified a need for additional pole mounted ganged load break switches within the system, minimizing system losses, providing improved contingency options during outage events, providing a means to minimize the area affected. The program will target the installation of 8 additional units.

Estimated Cost= $ 76,750.00 ***Project #2018-0010***

9. Victoria Avenue Fly Rd South Ext Phase I. (2017 Carryover) **Investment Category SR**

The Project Scope involves the overbuild of an existing 3-phase 8.2 KV primary line on Victoria Ave in place, and constructed with a 3-phase 27.6KV top circuit for approximately 2.0 KM. Construction involves the installation of 32-new 45' poles, transfer of existing primary cable, and installation of 2.0KM of new 556MCM Primary and Neutral conductor from Fly Rd South to Seventh Ave. The Project is being initiated to provide a 27.6KV tie to town of Jordan Station Benefits include improved supply reliability and flexibility on the system during contingencies & system configuration by tying the F-1 Feeder from Vineland D.S to the M-5 Feeder from NWMTS.

Estimated Cost = $ 401,629.00 ***Project #2018-0012***

10. Victoria Avenue Phase II. **Investment Category SR**

The Project Scope involves the rebuild of existing 3-phase 8.2 KV primary line on Victoria Ave in place, and constructed to 3-phase 27.6KV for approximately 2.0 KM from Fly Rd going South. Construction involves the installation of 32-new 45' poles, transfer of existing primary cable, and installation of 2.0KM of new Neutral conductor on Seventh Avenue from the Victoria Avenue to Nineteenth St. The Project is being initiated to provide a 27.6KV tie between Vineland Station F-1 to the M-5 from MWMTS Station Benefits include improved supply reliability and flexibility on the system during contingencies & system configuration.

Estimated Cost = $558,441.00 ***Project #2018-0008***

11. 1-Phase Hydraulic Recloser Upgrades—10-Units **Investment Category SS**

Approaching end of life cycles, and relating to the 5-year Wi-Max deployment plan, a requirement has been identified, for the replacement of 10-existing pole mounted hydraulic reclosures. There are approximately 90 oil filled units in service on the system. 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. The solid dielectric insulation eliminates the oil used in the older units, making them less of an environmental concern.

Estimated Cost= $ 53,900.00 ***Project #2018-0013***

12. Kalar T.S.Protective Relaying Upgrade Installation **Investment Category SR**

Project scope involves Upgrade of Protective Relaying/Communication Equipment in conjunction with upgrades which are currently underway by Hydro One at the Allanburg facility. Material purchased in 2017, Installation slated for 2018 to fit with Hydro One project schedule. The western facing portion of the perimeter wall that surrounds the Kalar Transformer Station has experienced degradation of the structural foundation. The wall sections have physically settled which has resulted in cracking and separation of the block wall components. The wall is required to be removed, the foundations replaced, and the wall reconstructed.

Estimated Cost= $ 200,000.00 ***Project #2018-0025***

13. Chippawa River Crossing **Investment Category SR**

Project scope involves the replacement of 0.75 KM. of urban overhead 13.8 KV 3-phase primary line along Reilly St., across the Chippawa River to Sophia St. Includes the replacement of end of life steel structures supporting the river crossing with concrete poles. Benefits include improved system losses, improved equipment clearances, reinforcement & capacity increase of the supply in the area with redundancy provisions.

Estimated Cost= $ 400,396.00 ***Project #2018-0016***

14. Portage Rd--Mountain Road to Church's Lane **Investment Category SR**

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= $ 383,291.00 ***Project #2018-0017***

15. Oakwood Drive--Pole #111-25 to Pole #98-7 **Investment Category SR**

Project scope involves replacement of 1.5 KM. of an urban overhead primary distribution line, with an overhead 15 KV 600 amp class main 3-phase line in the same alignment as the existing. Installation of 25-new 50' wood poles, 7-Single Phase, 2-Three Phase transformers, transfer 3-three phase & 1-Single Phase Underground Primary Risers, and transfer 24-existing Residential triplex services. Since the original install this section of line has changed function from a radial feed, and has been incorporated into a tie between 2-Transformer Stations, without re-conductoring to facilitate the ampacity increase. System benefits include the replacement of aging equipment originally installed in 1970, system loss reduction, improved reliability, and capacity increase.

Estimated Cost= $ 648,476.00 ***Project #2018-0002***

16. <u>Line Relocations due to Municipal Road Improvement requirements. Category SA</u>

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: $520,813.00 (recoverable $260,000) ***Project #2018-0xxx***

17. Replacement of Poles identified with limited Structural Integrity. Category SR

The natural degradation of wooden utility poles is an ongoing issue. Per the Distribution System Code, 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. In the Niagara Area pole replacements are beginning to level off as cycles begin to repeat, with a structured treatment program implemented during the testing cycle to increase the poles life cycle. The average cost per pole change is approximately $ 5,000.

Estimated Costs: $ 624,352.00 ***Project #2018-1010/2010***

18. Replacement of Kiosks with Transformers, EFD & Posi-tect Switches Category SR

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 2013.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. 57-Units remain on the 15KV System, and 60-Units remain on the 5KV System. For 2018 the plan is to replace 1 to 2 units.

Estimated cost: $100,407.00 ***Project #2018-0020***

19. System Sustainment Allowance. Investment Category SS

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 ***Project #2018-1007/2007***

20. Subdivisions and New Residential Services Investment Category SA

Lot servicing of existing	***$417,000.00***
Recoverable	***($417,000.00)***

21. Connection and energizing of new subs Investment Category SA

Connection and energizing of new subs	***$482,004.00***
Recoverable	***($482,004.00)***

22. <u>Demand Based System Reinforcements for New Commercial Service Connections. Investment Category SA</u>

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 ***Project #2018-1008/2008***
(recoverable $728,000.00)

23. **<u>Metering General</u>** **$255,000.00**

24. **<u>Metering MIST</u>** ***$410.000.00***

APPENDIX C

General Equipment - 2018

	2018 Budget
Ergonomic Office Equipment	5,000
2 Defibrillators	5,000
Mail machine Inserter	60,120
General Equipment as needed	11,000
	81,120

APPENDIX D

Hardware - 2018

Function	Item	Purpose	Project	Approx Cost
Hyperconvergence Virtual Servers & Physical Servers				
	Adding Vxrail node for expansion - Niagara Falls		Hyperconvergence model - each node allows for placement of 20 existing servers; primary node and redundancy node+ room for growth	$ 84,272.39
	Adding Vxrail node for expansion - Smithville		Hyperconvergence Growth	$ 84,272.39
	New Cognos Server vs BI server		Will be put on Vxrail so no cost other than Windows license	1,200.00
	New File Nexus		Will be put on Vxrail so no cost other than Windows license	1,200.00
Printers				
	Replacement of HP bill printer		Upgrade due; new bill format	50,139.00
	Replacement of T620	Replacement of current T620	Replacement as required	2,500.00
	Lexmark	Report printer	Replacement as required	2,500.00
Phones				
	NuVox hardware		Answering service solution	10,000.00
	Cell phones		Replacement as required	10,350.00
PC / Monitor				
	PC and Monitor Replacements	2 PCs required in reception area for phone upgrade; 3 replacements	Replacement as required	4,500.00

Function	Item	Purpose	Project	Approx Cost
		Finance - 2: Lorie and Frances; Reception - 1; Customer Service - 2: Chris and Charlene; Billing - 2: Sue and Bonnie; BAS - 4: Karen and staff of 3; IT - 4: Anthony and staff of 3; CDM - 7: requested for 2018.	Standardize to 24" monitor	4,500.00
	Laptops / Tablets	Deployment of Inservice/Vegetation field use in Operations, and mcare in Metering; Laptop/Tablet for CDM; Laptops for each of the meeting rooms in Niagara Falls and Smithville	As required	5,000.00
LCD Projectors				
	NEC VT595 XGA 2000 ANSI LUNCENS PROJECTORS	Niagara Falls and West Lincoln Training Room LCD Projectors (not mounted)	Replace as required	1,000.00
Equipment	UPS Batteries for Niagara Falls		Includes install & removal	14,610.00
	3 headsets for - Ethan, Weston, Garret		Use for webinars and training	997.00
	Headsets - jabra 9470 - for customer Service		Use for webinars and training	4,020.00
	Hearing Equipment		New requirement	10,000.00
TOTAL HARDWARE				**291,060.78**

APPENDIX E

Software - 2018

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	Hexagon	$ 75,000.00
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	Hexagon	$ 10,000.00
All	Service Location Request/SPOT	Purchase or development of spot replacement	Silverblaze	$ 66,500.00
Human Resources	Vacation Workflow intelligence	software and integration tool	BDO/Microsoft	$ 20,000.00
Billing and Customer Service	CIS Updates	Customer Engagement Enhancement and workflow efficiencies	Northstar	$ 176,000.00
Finance / Human Resources	eConnect	Interface software		$ 5,000.00
Ops/Finance	Who's Where 5.0	Professional services	Silverblaze	$ 11,000.00
All	Phone system Upgrade - software update, professional services to update call workflow	Professional services, programming		$ 5,000.00
TOTAL SOFTWARE				**$368,500**

APPENDIX F

Vehicles and Transportation Other Equipment 2018

Description	2018 Budget
Vehicles < 3 tonnes	
Meter Van Replace #48	40,000
TR #53 replace	45,000
Total	85,000

Vehicles > 3 tonnes	**2018 Budget**
Finishing body Broderson Crane	35,000
	35,000

Transportation Equipment	**2018 Budget**
Cable pulling machine for installing UG wire	223,000
	223,000
Total	343,000

APPENDIX G

Tools Budget 2018

Tools and Equipment for Vehicles	2018 Budget
Miscellaneous Replacement Tools	50,000
	50,000
Tools for Garage	
Various shop tools	11,000
Total tools for garage	11,000
Total Tool Budget	61,000

APPENDIX H

Communication Equipment - 2018

	2018 Budget
Wi-max project	115,000
Total	**115,000**

Niagara Peninsula Energy Inc.
Capital Budget 2012 - 2021
(000's)

	Actual 2012	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Projected 2017	Proposed Budget 2018	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	357	1,435	1,400	50	50
Sub Total	631	1,913	1,613	469	53	357	1,435	1,400	50	50
Distribution Station	684	501	514	1	0	188	0	0	0	0
Transformer Station	0	0	16	0	0	97	200	0	0	0
Overhead Distribution	3,663	4,786	4,362	5,219	6,307	5,408	5,548	5,471	5,474	5,200
Underground Distribution	3,148	2,476	3,470	5,550	5,007	3,977	3,664	2,835	3,450	3,700
Distribution Transformers	1,247	1,371	1,135	2,319	1,508	1,663	1,205	1,281	1,355	1,400
Meters	171	193	396	185	331	735	255	235	435	435
Smart Meters/MIST meters	786	82	2,049	144	159	200	410	150	150	0
Sub Total	9,699	9,409	11,942	13,418	13,311	12,267	11,282	9,972	10,864	10,735
Office Furniture & Equipment	112	170	177	26	28	23	81	35	20	20
Computer Equipment, Hardware	371	276	279	249	241	403	291	241	300	300
Vehicles < 3 tonnes	104	158	0	236	75	177	85	142	100	150
Vehicles > 3 tonnes	1,057	1,172	631	254	643	697	35	442	450	450
Vehicle Other	0	0	21	0	75	0	223	22	0	0
Stores Equipment	0	0	32	55	0	0	0	0	0	0
Tools, Shop & Garage Equipment	133	83	60	67	119	95	61	75	75	75
Measurement & Testing Equipment	0	0	0	0	0	0	0	0	0	0
Communication equipment	332	344	228	66	302	32	115	150	200	0
Miscellaneous equipment	0	0	0	0	0	0	0	0	0	0
Sub Total	2,109	2,203	1,428	952	1,482	1,428	891	1,106	1,145	995
Total Capital before capital contributions	**12,438**	**13,525**	**14,983**	**14,839**	**14,847**	**14,052**	**13,608**	**12,478**	**12,059**	**11,780**
Capital Contributions	(1,585)	(991)	(1,388)	(5,600)	(3,995)	(2,633)	(2,135)	(1,537)	(1,537)	(1,537)
Net property plant & equipment	**10,853**	**12,534**	**13,595**	**9,238**	**10,852**	**11,419**	**11,473**	**10,941**	**10,522**	**10,243**
Intangible assets										
Computer Software	213	115	538	183	342	729	369	353	350	300
Total Intangibles	**213**	**115**	**538**	**183**	**342**	**729**	**369**	**353**	**350**	**300**
Total Gross Capital Expenditures	**11,066**	**12,649**	**14,133**	**9,421**	**11,194**	**12,147**	**11,841**	**11,294**	**10,872**	**10,543**
Vehicle Disposals	0	0	(441)	(504)	(496)	(826)	(349)	(436)	(436)	(436)
Net Captial Additions after disposals	**11,066**	**12,649**	**13,692**	**8,918**	**10,698**	**11,321**	**11,492**	**10,858**	**10,436**	**10,107**

Average Net Capital Expenditures - 7 year (2012 - 2018)	**11,405**	**11 Year Average**	**10,928**
Average Fixed Asset additions COS rate Application 2015 net of average $850K capital contributions	**10,558**	**5 year average 2015-2019**	**10,658**

Appendix 1-5

NPEI 2017 Capital and Operating Budgets

niagara peninsula energy inc.

2017
Capital
&
Operating
Budgets

Table of Contents

Niagara Peninsula Energy Inc.
Budget Report 2017

This report is prepared for the purpose of reviewing the significant factors affecting the 2016 and 2017 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.

Electricity Industry Outlook

The electricity industry continues to change at a rapid pace and has done so for more than a decade. Per the Agile Utility report prepared by KPMG in 2016; "Disruptive forces related to changing customer demands, regulatory change, rapid technology advancements, and capital sourcing are creating a new industry environment to which LDC's will increasingly need to adapt. Individual utilities and markets will respond to these disruptive forces in different ways and at different paces, but the industry model as a whole will evolve over time to become flatter, more agile, and more able to respond to internal and external market forces. It is expected that the role of the traditional utilities will evolve into more of a network integrator."

NPEI is becoming a provider of energy services through a data-driven, customer-centric-system operations platform. This platform is potentially capable of managing responsive loads and supporting infrastructure for electric vehicles, storage devices and distributed generation. The regulatory framework designed to encourage our business diversification has also introduced a new element into the utility's sector's environment: competition. Other market entrants are looking to provide tailored energy products and services, utilizing similar technology platforms, and will potentially cut into utility market share. Competition drives both necessity and urgency for NPEI to change and grow, while balancing environmental, social and economic sustainability. A requirement to technological innovation that goes beyond incremental productivity improvements is needed. With funding and support from policymakers, regulators, and private industry, the electricity sector must develop, test and deploy new ideas, devices and processes that will meet the shifting needs and expectations of tomorrow's customers.

Long Term Energy Plan (LTEP)

In 2016 the Ontario Government will undertake consultations on the next iteration of the Long Term Energy Plan (LTEP). With the expected passage of Bill 135, the Ministry of Energy will lead the development of the LTEP with technical input from the IESO. Consultations with stakeholders and the public will commence in the summer of 2016. The LTEP is expected to be released in 2017 which will serve as the energy policy platform for the government leading into the 2018 election. The LTEP will also include results from the bottom-up Achievable Potential Study that is currently being undertaken by the IESO as part of the midterm review of the 2015-2020 Conservation First Framework.

Mergers and acquisitions

Over the past few years, some merger and acquisition activity has been observed among the LDC's. Hydro One Networks expressed interest in quite a number of utilities; thus far Norfolk Power and Woodstock Hydro have been purchased by Hydro One. Most recently the City of Orillia has made the decision to sell Orillia Power Distribution Corp. to Hydro One. Also, Energy+ (formerly Cambridge) purchased Brant County Power. Peterborough, Collingwood (50%), Orillia, Wasaga, Innisfil, Centre Wellington, St. Thomas and West Coast Huron have been rumoured to be potentially purchased.

Most recently the development of the "mega-merger", involving multiple large companies of Enersource, Horizon Utilities and Powerstream along with the purchase of Hydro One Brampton has been emerging. One year subsequent to the "mega-merger" announcement the application was submitted to the Ontario Energy Board, a process originally estimated to take six months. The result, MergeCo, would become the second-largest municipally-owned electric utility company in North America, serving close to one million customers in the Greater Toronto and Hamilton Area. Another merger, currently in the early stages is between Oshawa Power and Utilities Corporation, Whitby Hydro and Veridian.

These mergers and acquisitions have the potential to change the LDC landscape in significant ways. Larger utilities have the potential to leverage scale to create efficiencies and broaden the scope of their businesses. This can result in changes in communities who have traditionally had local utilities; it can also result in publicly-traded entities purchasing companies from municipalities, creating a different relationship within the community as well.

Energy Storage

Energy storage technology will continue to evolve. Several technologies are available however battery prices continue to drop and will be the preferred technology in the short term. Battery prices have declined more than 50 percent since 2010, making them more attractive to property developers for malls, apartments, hospitals, universities and others. If this trend continues, commercial and industrial customer use of lithium-ion batteries for energy storage could be economically viable in the medium term.

Energy storage includes technologies such as pumped hydroelectric systems and underground compressed-air storage. Energy storage allows power to be stored and released when most needed. On a larger scale this technology provides distributors with these potential advantages:

- Allows the integration of intermittent renewable energy into the power grid

- Assists meeting demands for resilience and reliability, cleaner energy options, and enhanced services such as electric vehicle charging stations
- Addresses capacity shortfalls during usage spikes, allowing T&D infrastructure to be deferred
- Provides a higher level of reliability, safety, and security, by improving control of fluctuating voltage and frequency introduced by intermittent generation

The global market for energy storage is expected to quadruple by 2020. Experiments and implementation are taking place globally and as a result competition for this technology is increasing. Investments in energy storage by distributors is not easy as it is more expensive than some other alternatives, but with prices continuing to decline there will be more cost effective opportunities in the future. Three possible approaches for acquiring energy storage systems include: ownership; pay-per-need; and third party incentives.

Electric Vehicles

During the past few years, several models of plug-in electric vehicles (PEVs), including battery electric vehicles (EVs) and plug-in hybrid electric vehicles (PHEVs), have been introduced in the light-duty vehicle market. Charging infrastructure is crucial to the success of these kinds of vehicles. To address this issue, plans have been established to promote the development of infrastructure through financial incentives for the building of new public and private recharging facilities.

Efficient batteries are the key to the future development of EV. There remains significant scope for battery cost reductions, some of which materialized during the projected timeframe. Widespread market uptake of electric cars does not depend on cost reductions alone. Consumers also need to be convinced that the performance of an electric vehicle is at least as attractive as that of a conventional vehicle, even if its purchase comes at higher initial cost. That means overcoming limitations to driving range, reducing long recharging times and ensuring the widespread availability of recharging stations. Tesla has received deposits for 400,000 reservations of its Model 3 EV. The $35,000 mass market electric car was unveiled March 31 and has a designated launch date of late 2017. Tesla plans to build 500,000 EVs by 2018.

Investment in electric vehicle (EV) infrastructure will also be a main component of climate change strategies along with enhanced energy efficient measures for residential and business customers.

Cyber Security

In February, the OEB announced a review of cyber security best practices with respect to the distribution grid with an aim to propose an industry standard for managing cyber security risks by the end of 2016. The OEB said it will use the working group to establish a common framework referencing recognized industry standards, policy guidelines and auditing requirements. Cyber risk must me managed through best practices, with the goal to reduce the likelihood and impact of a cyber-event to the company’s operation, assets and reputation.

Over the past decade, the electricity sector has become increasingly dependent on digital technology, to increase efficiency and maintain reliability. Information technology and industrial control systems are vulnerable to attacks and misuse. Historically systems were composed of propriety technologies with limited connection to corporate networks or the internet. More recently, commercial hardware platforms and software applications are causing a move from an isolated environment to an interconnected environment. The increase of interconnections of systems also increases vulnerabilities. Attacks can cause damage to assets, individuals or reliability. The goal is to manage these increased risks.

Revenue Decoupling

The OEB has approved a rete 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.

2016 Projected Balance Sheet

Total assets are projected at $234M, which is up 10% or $21M from the 2015 total assets. This is mainly due to an increase in Cash of $15M as NPEI obtained a $20M loan in September of 2016. Also there was an increase in fixed assets of $8.2M net of accumulated depreciation and excluding capital contributions. Under IFRS presentation capital contributions are recorded as Deferred Revenue in the liabilities section of the balance sheet. Regulatory asset balances are projected to decrease by $4.8M.

Capital Additions 2016

Significant capital projects completed in 2016 are illustrated in the table below. The table also details the capital contributions received in 2016 which are now recorded in the Liabilities section on the Balance Sheet.

Project	Projected 2016 Investment	2016 Budget	2016 Budget Variance
Niagara Region Wind Corporation-Customer Demand project	1,580,238		
Customer Demand work-projects <$5K	645,394		
Other Capital expenditures-Customer Demand projects < $50K	775,000	1,007,500	(1,993,132)
Kiosk Replacement Program	1,097,827	841,137	(256,690)
Sustainment Capital-allowance for unexpected failures/deficiencies	868,385	680,000	(188,385)
Pole Replacement Program	650,616	536,000	(114,616)
Frederica-Dorchester-Drummond Overhead replacement	616,837	671,753	54,916
Overhead to Underground conversion Rolling AcresPhaseIII	613,006	405,867	(207,139)
Underground subdivisions	574,802		
New Subdivisions	732,784	737,004	(570,582)
Oldfield Road 3-Ph Pole Line	228,988		(228,988)
Downtown Core PILCDSTA De-commision	532,524	795,701	263,177
Willoughby Dr-MainSt-Cattell-Overhead replacement	480,080	369,271	(110,809)
Metering Capital Costs-including MIST meters	435,596	480,860	45,264
Jordan Rd-Voltage ConverPh III	431,315	335,377	(95,938)
Willoughby Ext-Cattell-Weinbre	384,652	380,290	(4,362)
Clifton Hill Primary Upgrade	310,216	237,796	(72,420)
Padmount Switchgear Replace	271,110	250,000	(21,110)
Dorchester-Mcleod-Dunn-expansion to accommodate load growth & reliability	208,485	531,912	323,427
Overhead Line Rebuild Program	195,920		(195,920)
NS&T Hwy Overhead Crossing Replacement	163,094	272,236	109,142
600MCM U/G Install Glenholm-Franklin	150,000	133,262	(16,738)
Mountain St Ph II	100,739		(100,739)
Additional Sectionalize Switch	87,250	73,000	(14,250)
City of Niagara Falls Relocation Desson Ave	75,931		(75,931)
1-Phase Hydraulic Reclosure	53,575	100,000	46,425
Oakwood Drive -Overhead replacement	0	611,940	611,940
Dorchester-Mountain-Riall Street-Overhead replacement	0	626,867	626,867
Victoria Avenue Fly Road South PH 1-overbuild existing 3-phase line	0	298,862	298,862
Lightning Mitigation program	0	30,000	30,000
Road relocations	39,000	500,000	461,000
Subdivision assets paid by developers; owned by NPEI after subdivision is energized	1,317,000		(1,317,000)
Total Distribution Assets	13,620,362	10,906,635	(2,713,727)
Office furniture and equipment	25,000	20,000	(5,000)
Computer Hardware additions	248,000	242,000	(6,000)
Software additions	357,000	357,000	0
Concrete pads and new pole bunks	52,000	87,000	35,000
Fleet replacements excluding disposals and Tools	994,000	910,000	(84,000)
Wi-max communication-Campden Tower	306,000	150,000	(156,000)
Total General Plant & Equipment	1,982,000	1,766,000	(216,000)
Total Fixed Asset Additions	**15,602,362**	**12,672,635**	**(2,929,727)**
Capital Contributions			
Capital Contributions from Customers	(1,196,000)	(800,000)	396,000
Capital Contribution Niagara Regional Wind Corp	(1,580,227)		1,580,227
Capital Contributions from subdivisions	(1,324,000)		1,324,000
Subdivision assets paid by developers; owned by NPEI after subdivision is energized	(1,317,000)		1,317,000
Total Capital Contributions	**(5,417,227)**	**(800,000)**	**4,617,227**
Net Fixed Asset Additions excluding Vehicle Disposals of $547K	**10,185,135**	**11,872,635**	**1,687,500**

The 2016 distribution assets additions are projected at $13.6M, which is $2.7M higher than the 2016 budget amount of $10.9M. This variance is mainly due to the Niagara Region Wind Corporation Customer Demand project of $1.6M and $1.3M of subdivision assets which have been installed and paid for by developers, with NPEI assuming ownership after the subdivision has been completed and energized. The cost of these subdivision assets is offset by an equal capital contribution of $1.3M. When NPEI assumes ownership of these assets, there is an increase to total fixed assets, but no impact to NPEI's cash position.

Several capital projects that were originally budgeted in 2016 were not completed, and have been carried forward into the 2017 capital budget. 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 Niagara Region Wind Corporation 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. Significant 2016 subdivision projects in the Niagara Falls area include Chippawa West Phase II Stage II $209K, Oldfield Estates Phase II $181K, Warren Woods Phase IV $173K and Oldfield Estates Phase III $54K. There was also a Customer Demand project, Oldfield Road 3-Phase Pole Line project for $229K, which was required in order to provide servicing to the Oldfield Estates subdivision. The Victoria Avenue Fly Road South Phase 1, Oakwood Drive Overhead Replacement and Dorchester – Mountain to Riall Overhead Replacement projects have all been carried forward to the 2017 capital budget.

Capital contributions for 2016 are projected at $5.4M, which is $4.6M higher than the 2016 budget of $800K. The variance is mainly due to the Niagara Region Wind Corporation Customer Demand Project of $1.6M, subdivision capital contributions billed of $1.3M and subdivision assets which have been installed and paid for by developers of $1.3M.

Building expenditures are projected at $52K, which includes concrete pads and pole bunks. Office Equipment is projected at $25K and includes surveillance camera equipment, a new gate reader and general office equipment. Computer hardware additions are projected at $248K, which includes 2 new servers, the integration of the phone system to the CIS/Outage Management System and virtual environment conversion. Computer software additions are projected at $357K, and include second layer malware, SQL server licensing, automated voice callback software, Work Management / Outage Management software, Northstar CIS upgrades and virtual environment conversion.

Vehicles < 3 tonnes are projected at $75K, which includes the replacement of 2 pick-up trucks. Vehicles > 3 tonnes are projected at $725K, and includes the replacement of a 1996 46' Material Handler and a 1993 Radial Boom Derrick. Other Vehicles are projected at $75K, which is for the replacement of the backhoe with a Bobcat Skid Steer. Tools and Equipment is projected at $119K, which includes a Powermaster Meter Test system, garage compressor, tools for the new trucks and various replacement tools.

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 2016 is projected at $306K, which includes the design and construction of a new communications tower at the Campden DS. The 2016 budget for Communications Equipment was $150K. NPEI had the engineering resources available to complete the entire Campden DS tower project in 2016.

The total 2016 projected additions for vehicles, equipment and software is $2.0M, which is $216K higher than the budgeted amount of $1.8M. The variance is mainly due to the Communications Equipment cost being higher than budgeted by $156K due to completing the entire Campden DS tower within 2016, and the Powermaster Meter Test System for $50K. The Meter Test System consists of 2 analyzer units which are required for the installation of MIST Meters, and were purchased to replace 2 existing analyzers due to age and reliability.

Regulatory Assets are projected to decrease by $4.7M. Effective May 1, 2015, NPEI had included in the regulatory assets a rate rider for stranded meters. This rate rider was for a 2 year period and it is projected to recover $656K in 2016 and $224K in 2017. The rate rider for stranded meters will end April 30, 2017.

Liabilities and Share Holders Equity 2016

Current liabilities are projected to be $25.8M at the end of 2016. This is an increase of $2.3M or 10%. The December 2016 power bill payable is projected to be $2.6M higher than the December 2015 power bill. In 2015 a $1.3M power bill prepayment was made to the IESO prior to year end however, it is projected this prepayment will not occur in 2016. Due to the cost of power being higher in 2016 than in 2015, it is projected the 2016 year end power bill will exceed the 2015 year end power bill.

Non-current liabilities are projected to increase by $23.3M which is due to NPEI obtaining a $20M loan in September 2016. This new loan is with Meridian Credit Union and carries a term of 10 years at 2.60% annual interest. The new loan is an interest only loan where no principal repayments are to be made.

Capital contributions are projected to be $5.4M higher in 2016. See the table provided above. The capital contributions received in 2016 are as follows: Niagara Region Wind Corp $1.6M; capital contributions from subdivisions $1.3M; capital contributions from customer demand projects in the amount of$1.2M; and $1.3M of capital contributions related to assets paid for by developers of subdivisions whereby NPEI assumes ownership of these assets upon the subdivision lots being energized.

Regulatory Liabilities are projected to be $5.7M lower in 2016 than 2015. Effective May 1, 2015 NPEI had a rate rider for the disposition of Account 1576 which was related to the changing of the lives of fixed assets. This rate rider was effective for 2 years and will finish April 30, 2017. Effective May 1, 2016, NPEI added a new rate rider related to the Adjustment to the 2015 Interim Rates. The total rate rider was for $272K and will be in effective for 12 months, finishing April 30, 2017. This rate rider was related to the adjustment to NPEI's working capital allowance from 13% to 10.48% as a result of NPEI filing a lead/lag study with the Ontario Energy Board.

In 2016, NPEI paid a total dividend of $1.4M to its shareholders proportionate to the shares held.

2016 Projected Income Statement

Regulatory Net Income does not include the depreciation expense for the FMV bump of $1,085K. Projected 2016 regulatory net income after tax and net movement in regulatory balances is $3,614K which is $857K less than budget and $1.7M less than 2015.

The Gross profit is projected at $453K less than budget and $520K less than 2015. Effective May 1, 2016 for a period of twelve months, NPEI has a rate rider for the Adjustment to the 2015 Interim Rates. This rate rider is a repayment to the customer and is included as negative revenue in the amount of $182k. Removing the impact of this rate rider would result in Gross profit being $271K less than budget and $338K less than 2015. The rate rider was finalized subsequent to the budget approval process. The 2015 rates were approved by the OEB on an interim basis until the working capital allowance rate was finalized. This entailed NPEI to prepare a lead/lag study. The budget revenue and 2015 Actuals included a WCA of 13%; however the OEB approved a WCA of 10.48%.

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. Combining the 2016 projected Service Charge and Distribution Volumetric Charge would result is a $398K variance lower than budget and a $413K variance lower than 2015. The reduced distribution volumetric revenue is due to customers using less energy as a result of price and/or conservation and demand initiatives.

Other revenue in 2016 is less than 2015 by $234K which is due to a performance incentive received from the IESO in 2015 for exceeding its energy savings target related to the 2011 to 2014 CDM programs in the amount of $278K. In 2016, other revenue includes $114K of labour recoveries billed to the Niagara Regional Wind Corp for the wind project.

Cost of power is projected to increase over 2015 by $14.5 or 10%. This increase in Cost of power is anticipated to continue into future years.

Total expenses are projected at $24,822K which is $854K over budget and $766K over 2015. Total operation, maintenance, utilization, billing & collecting and general administration expenses for 2016 are projected at $17,265K which is $760K over budget and $398K over 2015.

Of the $760K variance to budget, labour accounts for $319K and outside purchases accounts for $441K.

The budget labour variance consists of a Systems Analyst, a Human Resources Assistant, and a Manager of Engineering for six months.

The budget outside purchases variance includes higher costs for locates $64K, pad-mount inspections $71K, tree trimming $30K and increased maintenance at the Kalar TS $80K, civil work performed at Station #22 $16K, totaling $261K.

Outside purchases in General and Administration increased over budget by $28K. Legal fees were less than budget by $72K, audit expenses were greater than budget by $15K due to the IFRS audit performed in January 2016. Insurance exceeded budget by $63K. Regulatory expenses exceed budget by $63K due to the OEB increasing their assessment fees.

Billing and collecting expenses exceeded budget by $138K. The 2016 budget assumed 374 MIST (Metering Inside Settlement Timeframe) meters for the GS<50 kW rate class would be installed by the end of 2016 and there would be a reduction in the meter reading costs included in OM&A. Due to resource issues and technology it is anticipated approximately 140 MIST meters will be installed in the fourth quarter of 2016. As a result meter reading expenses exceed budget by $26K. Postage is greater than the 2016 budget by $41K as well as programming expenses are greater by $43K. NPEI undertook a Customer Engagement initiative to develop a Welcome Package for new customers as well as a video titled “Get to know your Bill”. The cost of this initiative was $53K and was not included in the budget. This cost will not be incurred on an annual basis.

NPEI obtained a loan from Meridian Credit Union in September 2016. The additional interest expense not included in the budget is projected at $130K.

OM&A compared to 2015 is $398K higher. Increase in labour of $540K offset by a decrease in outside purchases of $142K compared to 2015. The labour variance consists of a wage increase of $180K, the Controller returning from a maternity leave, an additional Systems Analyst, a human resource assistant, and a manager of engineering for half a year. Outside purchases in 2015 included consulting costs related to Strategic Planning and projects related to Human Resources and succession planning. Also, in 2015 there were several events related to NPEI’s 100th anniversary.

2017 Budget Balance Sheet

Total Assets are budgeted at $234M which is $0.3M higher than 2016 projected total assets. Capital additions of fixed assets in 2017 total $12.1M. Intangible asset additions total $1.1M.

Cash has decreased by $5.8M which is due to the 2017 capital investment, principle repayment of existing loans in the amount of $1.5M and the net repayment of regulatory liabilities in the amount of $3.1M.

The rate riders for the stranded meter recovery, the repayment of account 1576 related to the change in accounting lives and the repayment of the Adjustment for 2015 Interim rates will expire April 30th, 2017.

Effective May 1, 2017, there will be two new rate riders in effect for 12 months; first the recovery of the lost revenue adjustment mechanism (LRAM) which relates to lost revenue from conservation and demand initiatives from the period of 2011 to 2015; the second is a repayment of deferral and variance account balances as at December 31, 2015 which relate to the retail settlement variances (power, global adjustment, wholesale market, network and connection variances) in the amount of $3.9M.

NPEI has a five year loan with TD bank which comes due June 2017. NPEI intends to refinance this loan in 2017 through the request for proposal process. NPEI does not intend to obtain any additional debt in 2017.

NPEI included a dividend payment of $1.4M in the 2017 budget.

Capital Additions 2017

Total fixed asset additions for 2017, net of vehicle disposals of $381K, are budgeted at $12.1M plus software additions of $1.1M for a total of $13.2M. Capital contributions are budgeted at $1.5M, for a net capital budget of $11.7M.

Gross capital additions related to the distribution system are budgeted at $10.8M, less capital contributions of $1.5M, for net total distribution system additions of $9.2M.

As in previous years, NPEI’s 2017 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 2017 Capital Projects. Three capital projects: Oakwood Drive Overhead Replacement, Victoria Avenue Fly Road South Phase 1 and Dorchester Mountain to Riall are projects that were originally scheduled to be completed in 2016. Due to the magnitude of customer demand and subdivision projects in 2016, and NPEI’s resources, these three projects were deferred until 2017.

APPENDIX B
List of Projects

Item	Project	Gross Capital Investment	Capital Contribution	Net Capital Investment
1	Dorchester - McLeod to Dunn Phase 2	359,131	0	359,131
2	Oakwood Drive - Overhead replacement -*deferred from 2016*	600,819	0	600,819
3	Padmount Switchgear replacement program	250,000	0	250,000
4	Station #14 Voltage Conversion Phase I	589,623	0	589,623
5	Brown Road extension - Montrose to Blackburn	189,664	0	189,664
6	Subdivision Rehabilitation Allowance	245,151	0	245,151
7	Additional sectionalizing switches	73,000	0	73,000
8	Victoria Avenue Fly Road South PH 1- *deferred from 2016*	308,719	0	308,719
9	1-Phase Hydraulic Reclosure Upgrades	100,000	0	100,000
10	Jordan Road Voltage Conversion Phase IV	561,614	0	561,614
11	Downtown Core PILCDSTA De-commissioning	292,171	0	292,171
12	Dorchester Mountain to Riall - *deferred from 2016*	678,670	0	678,670
13	Lightning Mitigation Measures	30,000	0	30,000
14	Chippawa Redundant Supply Upgrades Phase I	343,719	0	343,719
15	Heartland Road extension-Brown Road to Chippawa Creek	114,583	0	114,583
16	Station DS Power Transformer Replacement	200,000	0	200,000
17	Kalar TS Protection-Relay Upgrades	400,000	0	400,000
18	Line Relocations due to Municipal Road Improvements	500,000	(200,000)	300,000
19	Replacement of Poles identified with Structural Integrity	626,236	0	626,236
20	Kiosk replacement program	1,001,137	0	1,001,137
21	System Sustainment allowance	820,000	0	820,000
22	Subdivision Lot servicing of existing lots	275,000	(275,000)	0
23	Connection and energizing of new subdivisions	312,004	(312,004)	0
24	Subdivision Lot Rebates- new connections	250,000	0	250,000
25	Customer Demand Work	1,124,500	(750,000)	374,500
26	Metering - General	343,500	0	343,500
27	Metering - MIST	200,000	0	200,000
		10,789,240	**(1,537,004)**	**9,252,236**

Detailed descriptions of these capital projects can be found in the 2017 Capital projects section, Tab 5. See Appendix B.

Other Capital Additions

NPEI's 2017 budget for Other Capital Additions reflects the considerations of customer focus, encouraging operational effectiveness and responding to public policy.

Expenditures proposed in 2017 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 enable NPEI to maintain a modern and reliable fleet, which improves efficiency, safety and reliability during the construction of capital projects.

The 2017 budget for hardware and software provides for the management of cyber risk through increasing digital technological advancements.

The 2017 Wi-Max Communications Equipment budget will contribute to an improved communications network for efficient outage response and restoration.

Building

In 2017, NPEI has budgeted $193K for building expenditures, including $150K for architectural and engineering services relating to the redesign of the control room and garage area and $23K for the replacement of rooftop heating/air conditioning units. NPEI's current fleet maintenance facility in Niagara Falls is capable of performing vehicle services on only one vehicle at a time. Space is very limited, and the area is greater than 35 years of age. See Appendix A for details.

General Equipment

In 2017, NPEI has budgeted $11K for general equipment, and $9K for ergonomic office equipment. See Appendix C.

Hardware and Software

The Information Technology capital expenditures for 2017 continue to ensure that business goals are aligned to technological solutions. NPEI's network infrastructure will be optimized allowing for improved business uptime and resiliency, and a step towards becoming a network integrator between NPEI and its customers.

The hardware and software requirements within each area allow for the following goals to be met:

- Customer Engagement focus
- Effective and efficient business processes

- Support of risk and compliance management processes and methodology (enabling a methodology, not defining)
- Integrated, reliable, enterprise solutions
- Network integration and security
- Embedded business continuity practices, and continued update and testing of a Disaster Recovery Plan.

Hardware

The 2017 budgeted expenditures of $402K are related to the following projects/business needs:

- Virtual environment conversion from VM ware (Virtual Machine) to a hyper convergence model, to provide for growth and expanded contingency planning. NPEI has outgrown the current VM model and is at is capacity without additional investment. At its capacity, data vulnerabilities are found in recovery and growth. NPEI has explored and researched the hyper convergence model, which represents a technological advancement. Hyper convergence is storage in a server which includes all backup, disaster recovery, data movement and data efficiency. Upfront capital investment is required to create the structure. Annually, we will be able to add to the model based on need and growth. NPEI began the conversion process in 2016 with 2 nodes, and has budgeted for 2 further nodes in 2017. Each node is budgeted at $83K for a total of $166K in 2017, and allows for the replacement of 20 existing servers, which would carry a capital investment of over $200K.
- Network infrastructure (1 switch due to introduction of hyper convergence model and 1 replacement switch due every 3-5 years) $60K.
- Replacement of servers and storage devices due to end of life and business requirement (Outage Management System (OMS), File Nexus and back-up data storage due every 5 years) $104K
- Replacement of printers, engineering plotter, cameras, PCs and monitors due to age, usage and new business requirements for new hires. (due every 5 years or new business requirement) $64K

Software

Software required for business process improvement projects and new requirements, which promote efficiency and reliability, has been budgeted at $1.1M. Software requirements include the following:

- Work Management / Outage Management System (OMS) upgrade, which is a major upgrade including operating system upgrade. $275K.
- OMS / Customer Information System (CIS) interface which allows for one call entry to flow between the OMS and CIS. $35K.
- AMI ping (communication to and from meter infrastructure) within Outage Management System to broadcast to social media encouraging customer engagement and flow of information throughout the organization (one time investment with annual maintenance to continue) $130K.
- One additional G/Tech license (Required due to increased number of users) $28K.

- Additional Dispatcher license (Required due to increased number of users) $28K.
- Service Location Request / SPOT replacement (replacement of a legacy outgrown system providing for both operational efficiencies and customer engagement; upfront capital investment with annual maintenance to follow.) The legacy product was in place for more than 10 years and has reached a point where other newer subsystems and technologies cannot integrate with it; PCs cannot be updated while legacy application is on the desktop $67K.
- Interactive employee forms, workflow and tracking – upfront capital investment to encourage operational efficiency, leading to improved workflow, documentation and reporting $102K
- Great Plains upgrade (due every 3 years) $35K.
- Harris Northstar automation platform and bill presentment (annual regulatory requirements to avoid unknown costs when there is provincial change or mandate.) $75K.
- NPEI website upgrade to be more customer friendly (due every 3-5 years) $36K.
- File Nexus upgrade (due every 3 years) $15K.
- Anti-Virus Protection Appliance $75K.
- IT Shared Services (upfront capital investment for new business requirement enabling continued growth and business opportunities) $176K.

The software budget for 2017 includes $800K related to investments that will not occur on an annual basis. These projects all either relate directly to customer engagement, address a security or business risk or provide the opportunity for increased process efficiency or business opportunities.

The OMS upgrade, OMS interface to CIS and AMI ping communication to broadcast to social media represents a total of $440K. These expenditures can be linked directly to customer engagement and preferences.

The Anti-Virus Appliance addresses a security concern, providing anti-virus protection for NPEI's internal systems. 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. The IT shared services project allows for continued growth and business opportunities. The additional G/Tech and Dispatcher licenses are required due to the legacy licensing arrangement becoming inadequate for current usage.

The 2017 Information Technology focus is technology advancement encouraging business process improvement, efficiency, as well as, positioning NPEI for growth in data, as well as, business continuity and disaster recovery and planning. NPEI's technology infrastructure has matured and grown with the business. NPEI, in 2017, will take on technological advancements that previously we would not be able to explore the efficiencies. Over the past 5 years, NPEI has learned how the virtual environment can provide for growth as well as protection. Using this knowledge, NPEI has designed and planned for a virtual environment that will allow for data growth and vulnerability assessment to be met. This infrastructure is a change, as seen in the upfront investment in hardware, as well as, resource time to place us in a stream ready to address future growth and vulnerabilities. The Ontario Energy Board has challenged LDCs with being prepared for regulatory change, as well as, protection from cyber security. The 2017 budget line items within IT places NPEI in a position to address challenges directly, while meeting technology goals, focused on both the business units, and our customer.

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 D and E for details related to the hardware and software budgets.

Vehicles

NPEI has budgeted $695K for vehicles in 2017. This includes the replacement of a 2003 Freightliner single bucket truck, the replacement of a 1989 mobile crane, and the replacement of three pick-up trucks. Also included in the 2017 vehicle budget is an electric vehicle. See Appendix F for details.

Tools and Equipment for Vehicles

Tools and equipment in the amount of $82K 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 within the Lincoln/West Lincoln service territory, 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 III of the Project entails the replacement of the existing Communications Tower at the Niagara Falls Service Centre with a new unit which is 25% taller than the existing to allow for future System Expansion, and has been budgeted at $300K for 2017. See Appendix H.

2017 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"). NPEI's rates were approved by the OEB on an interim basis pending the filing of a lead/lag study addressing the 13% WCA used in the rate application. As noted above NPEI's rates were approved on a final basis effective May 1, 2016. Included in NPEI's rate tariff is a rate rider to reflect the Adjustment to the 2015 Interim rates.

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

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 2017 Distribution Revenue is based on the 2017 IRM rate application that was submitted to the OEB in September 2016.

As part of the Renewed Regulatory Framework in Electricity, the OEB indicated that the revenue decoupling consultation would move forward.

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 Cost of Service rate application included distribution revenue split for the Residential rate class of 58% Fixed, 42% Variable. Phase 1 effective from May 1, 2016 to April 30, 2017 included a Residential rate class split of 68.5% Fixed and 31.5% variable. Phase 2, effective from May 1, 2017 to April 30, 2018 includes a Residential rate class split of 79.1% fixed service charge revenue and 20.9% volumetric distribution revenue. Effective May 1, 2019, NPEI's residential rate class distribution revenue will be 100% fixed.

Cost of Power

Cost of power is budgeted at $170M in 2017 which is $4.5M higher than the 2016 projected and $19M higher than 2015. Cost of power in 2017 is budgeted at $25.7M higher than the cost of power calculated in the rate application.

Other Revenue

Other revenue is budgeted at $1.4M which is $85K lower than the projected 2016 due to labour recoveries received from the Niagara Regional Wind Corp. project which occurred in 2016. Total other revenue budgeted in 2017 is consistent with the rate application filing.

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 $17,671K excluding interest expense and depreciation are reflected in the 2017 budget. The projected 2016 OM&A expenses total $17,265K and 2015 OM&A expenses total $16,867K. In comparison to 2015, the budget 2017 OM&A expenses are higher by $804K or 4.76%.

The total increase of $406K or 2.3% consists of a labour increase of $416K, offset by a decrease of $10K in outside purchase expenditures, material, and equipment usage. The labour increase of $416K consists of the wage increase of $190K, succession planning in the amount of $188K for the GIS Technologist position for a full year, the Engineering Manager hired for succession planning in June 2016 and three returning co-op apprentices to be hired on contract for four months also a part of succession planning. 3 new positions in the amount of $134K with staggered start dates throughout 2017 as follows: a second union position for the control room, a Communications Coordinator at 40% recovery from distribution revenue and 60% from CDM funding and a Junior Business Analyst. This is offset by a decrease in labour of $114K which was billed to the Niagara Regional Wind Corp in 2016.

In comparison to 2015, the labour expense is budgeted at $956K higher in 2017. This is due to two years of wage increases at 2%; the Controller returning from a maternity leave in 2016, a software System Analysts hired in 2016, an HR assistant second contract renewal in 2016, a new GIS Technologist hired in mid-November of 2016 for succession planning, an Engineering Manager hired in June 2016 as part of succession planning and three co-op lineman apprentices to be hired on contract in 2017.

Other distribution expenses excluding labour are budgeted to decrease by $10K from 2016 projected and $153K lower than 2015.

In Operations and Maintenance, there was additional maintenance on the Kalar Transformer Station that was unanticipated in 2016 and expected to not be incurred in 2017. Locates, pad-mount transformer inspections and tree trimming all exceeded the 2016 budget and 2015 actual, however tree trimming is budgeted to decrease by $60k in 2017 due to the five year cyclical nature of the tree trimming program. Additional line school training has been budgeted in 2017; this expenditure is also cyclical in nature depending on the levels of NPEI's apprentices.

In Billing and Collecting, outside expenditures are budgeted to decrease by $33K from 2016. Meter reading costs are anticipated to decrease by $37K due to the MIST meter installation project; the Welcome packages related to customer engagement are not anticipated to be incurred in 2017 due to the receipt of these packages being in the fourth quarter of 2016, thereby resulting in a decrease of $40K. NPEI's current mail machine is 10 years old at the end of 2016 and has a zero net book value. NPEI will prepare the business case in 2017 to outsource this function. NPEI has included $60K in the 2017 budget for the outsourcing of mail.

In Utilization expenses, NPEI has included an additional $50K in the 2017 budget related to Canada's 150th birthday.

In General and Administration expenses, the 2017 budget is $24K higher than the 2016 projected and $104K lower than 2015. Legal fees are budgeted to be $82K lower than 2015 and $22k higher than 2016. Regulatory expenses are $74K higher in 2017 than 2015 due to the OEB restructuring its fees charged to LDC's in 2016. Insurance and property taxes are higher in 2017 than 2015 by $90K. These costs have been offset by a reduction in consulting of $137K related to strategic planning and the human resources succession planning projects held in 2015. Also, in 2015 there were expenditures related to NPEI's 100th anniversary that will not occur in 2017.

Interest Expense

Interest expense is budgeted at $2.7M in 2017. No new financing is anticipated at the time this budget has been prepared. Interest expense is higher than the projected 2016 amount of $291K due to NPEI obtaining a $20M ten year loan at 2.6% interest for 3 months in 2016 and a full year in 2017. Finance income is budgeted in 2017 to be higher that the projected 2016 and the 2015 actuals due to a higher cash position as a result of the new financing obtained in September 2016.

Depreciation Expense

Depreciation expense excluding the depreciation on FMV adjustment of fixed assets is budgeted at $7.1M which is $634K higher than projected 2016 depreciation expense and $1,007K higher than 2015. The main driver for this increase is the 2017 software budget of $1.1M. Software is depreciated over a period of 3 years, thereby increasing the 2017 depreciation expense. This increased depreciation will be high in both 2018 and 2019. The remaining increase is a result of the 2016 additions of $15M where the half year rule applies for depreciation calculation.

Wages and Benefits

NPEI's current collective agreement expires March 31, 2019. The 2017 budgeted wages and benefits include a 2% increase and there were no changes made in the budget to the current payroll benefit burden.

There were no retirements in 2016 and there are no budgeted retirements in 2017. The Controller returned from a maternity leave in 2016.

Two systems analysts were hired at the beginning of 2016. One is an additional position related to fulfilling system software requirements and one position related to fulfilling system hardware requirements, a business analyst was budgeted to be hired in 2016 but due to difficulties in hiring this position, NPEI has included the Business Analyst in the 2017 budget. A human resource assistant was hired on a contract basis in 2016 and the contract has been extended into the 2017 budget year. As part of succession planning an Engineering Manager was hired in June of 2016. Also, part of succession planning a GIS Technologist, union position, was hired mid-November of 2016 and was included in the 2017 budget for a full year.

NPEI is currently reviewing 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 has included a second union position to aid with the additional work load.

NPEI has also included a new Communications Coordinator to be at 40% of this hires wages to be covered by NPEI's distribution rates and 60% to be recovered by NPEI's CDM funding.

MIST meters-(Metering Inside Settlement Timeframe)

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 has included $43K in 2017 related to MIST meter reading costs included in the Net movement in regulatory balances line on the Income statement.

Net Income After Taxes

Net income after taxes is budgeted at $1.8M which is $0.7M lower than the projected 2016 net income after taxes and $2.4M lower than 2015.

The 2017 budgeted Return on Equity (ROE) on a deemed basis is estimated at 5.77%. Due to the retail settlement variances being unpredictable the income tax impact on deemed ROE was estimated at a high level. By performing a sensitivity analysis, adjusting the 2017 budgeted software additions from $1.1M to a more typical level of $320K (a decrease of $800K) would increase the 2017 deemed ROE by 0.34%, from 5.77% to 6.11%. Also, performing a sensitivity analysis on the impact of labour expense related to succession planning, the 2017 deemed ROE would increase by 0.23% from 5.77% to 6.00%. Combining both sensitivity analysis would result in a deemed ROE of 6.34% for 2017.

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 2017 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 recommends approval as follows:

1. The 2017 Capital budget of $12,099,000 be approved, this is comprised of gross capital additions of $10,789,000 offset by capital contributions in the amount of $1,537,000 for net distribution additions totalling $9,252,000, general plant and equipment, including the building and net of disposals of $1,310,000. Also the 2017 Intangible asset budgeted additions of $1,121,000 be approved.

2. The 2017 total operating expenditures in the amount of $25,828,000 including depreciation and depreciation related to the fair market value bump are approved.

Niagara Peninsula Energy
Financial Ratios
2014 to 2017

	2017 Budget	2016 Projected	2016 Budget	2015 Actual	2014 Actual
EBITDA % (Earnings Before Income Tax, Depreciation & Amortization	41.28%	42.39%	44.01%	48.08%	39.10%
Return on assets	1.22%	1.55%	2.48%	2.50%	1.96%
F/S Return on Equity	3.19%	4.06%	5.09%	6.06%	4.77%
Liquidity ratio	2.17	2.39	1.43	1.88	1.70
Ratio Debt/Total Assets	0.62	0.62	0.51	0.59	0.50
Debt/Equity Ratio	1.62	1.63	1.05	1.42	1.22
Calculation of Return On Equity (ROE) on a Deemed Basis	5.77%	7.26%	9.30%	8.96%	4.89%

Niagara Peninsula Energy
Projected Balance Sheet
As at December 31, 2016
(000's)

	Projected 2016	Actual 2015	$ Variance	% Variance
ASSETS				
Current Assets				
Cash	23,843	9,049	14,794	163%
Accounts Receivable	16,486	14,607	1,879	13%
Unbilled Revenue	18,682	17,383	1,299	7%
Payments in lieu of corporate taxes refundable	0	306	(306)	-100%
Inventories	1,493	1,499	(5)	0%
Prepaid Expenses	1,067	1,113	(46)	-4%
	61,571	**43,957**	**17,614**	**40%**
Fixed Assets				
Land	1,231	1,231	0	0%
Buildings	17,483	17,431	52	0%
Distribution Stations	9,383	9,383	0	0%
Transformer Station	6,576	6,576	0	0%
Distribution lines				
Overhead	115,420	109,419	6,000	5%
Underground	106,698	101,291	5,407	5%
Distribution transformers	45,657	43,928	1,729	4%
Distribution meters	11,165	10,681	484	5%
Trucks and Equipment	19,312	18,286	1,026	6%
	332,924	318,226	14,698	5%
Less: Accumulated Depreciation	(168,931)	(162,380)	(6,551)	4%
	163,993	**155,846**	**8,147**	**5%**
Intangible Assets				
Land rights	1,732	1,732	0	0%
Computer Software	3,769	3,412	357	10%
Total Intangible Assets	5,501	5,144	357	7%
Less: Accumulated Depreciation intangible assets	(4,355)	(4,065)	(290)	7%
	1,146	**1,079**	**67**	6%
Total non-current assets	**165,139**	**156,925**	8,214	5%
Regulatory balances				
Retail Cost Variances	224	140	84	60%
Retail Settlement Variances	0	4,646	(4,646)	-100%
Low Voltage Variances	1,165	579	586	101%
Lost revenue adjustment mechanism	495	481	14	3%
Stranded Meters	224	880	(656)	-75%
Other Regulatory Assets	55	36	19	52%
Regulatory related to income taxes	4,842	4,842	0	0%
Deferral & Variance Recovery 2012 application	0	250	(250)	-100%
Deferral & Variance Recovery 2014 application	119	0	119	100%
Deferral & Variance Recovery 2015 COS application	12	0	12	100%
	7,138	**11,855**	**(4,717)**	**-40%**
Total assets and regulatory balances	**233,848**	**212,737**	**21,111**	**10%**

Niagara Peninsula Energy
Projected Balance Sheet
As at December 31, 2016
(000's)

	Projected 2016	Actual 2015	$ Variance	% Variance
LIABILITIES				
Current Liabilities				
Accounts Payable	8,112	8,878	(767)	-9%
Power bill payable	13,417	10,758	2,660	25%
Taxes Payable	19	0	19	100%
Due to related parties	18	7	11	147%
Deferred OPA revenue & standard offer	1,187	831	357	43%
Customer Deposits	1,530	1,533	(3)	0%
Current Portion of long term debt	1466	1,420	46	3%
Total current liabilities	**25,750**	**23,427**	**2,323**	**10%**
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	52,975	34,442	18,534	54%
Employee Sick Leave Liability	51	52	(1)	-3%
Employee Future Benefits	2,665	2,504	161	6%
Deferred Capital Contributions	33,469	28,055	5,414	19%
Amortization capital contributions	(8,221)	(7,463)	(758)	10%
Deferred tax liabilities	1,480	1,480	(0)	0%
Total non-current liabilities	**108,024**	**84,674**	**23,350**	**28%**
Total liabilities	**133,775**	**108,102**	**25,673**	**24%**
Shares				
Share Capital	31,246	31,246	0	0%
Contributed Surplus	25,459	25,459	0	0%
Retained Earnings	32,318	31,189	1,129	4%
	89,023	**87,894**	**1,129**	**1%**
TOTAL LIABILITIES & EQUITY	**222,797**	**195,996**	**26,802**	**14%**
Regulatory Liabilities				
Retail Settlement Variances	7,246	9,221	(1,976)	-21%
Other Regulatory Assets	1,571	1,571	0	0%
Mist Meter Variance	88	44	44	101%
Smart Metering Entity Variance	37	0	37	100%
Regulatory related to income taxes	764	906	(142)	-16%
Deferral Change in Accounting Policy Depreciation	1,152	4,823	(3,671)	-76%
Deferral & Variance Recovery 2012 application	193	176	17	10%
	11,050	**16,741**	**(5,691)**	**-34%**
Total liabilities, equity and regulatory liabilities	**233,848**	**212,737**	**21,111**	**10%**

Niagara Peninsula Energy
Projected Statement of Operations vs Budget
For the year ending December 31, 2016
(000's)

	Projected 2016	Budget 2016	Projected vs Budget $ Variance	Projected vs Budget % Variance	Actual 2015	Projected 2016 vs Actual 2015 $ Variance	Projected 2016 vs Actual 2015 % Variance
SERVICE REVENUE							
Standard Supply Service	139,904	128,621	11,283	9%	127,172	12,732	10%
Wholesale, Network & Connection Charges	25,471	24,929	542	2%	23,682	1,788	8%
Service Charge	14,921	14,897	24	0%	14,010	911	7%
Distribution Volumetric Charge	13,479	13,901	(422)	-3%	14,803	(1,324)	-9%
Standard Supply Service Admin Charge	146	147	(1)	-1%	149	(4)	-3%
Retailer Revenue	35	45	(10)	-22%	39	(4)	-10%
Other Revenue	1,475	1,289	185	14%	1,709	(234)	-14%
Capital Contributions	758	987	(229)	-23%	613	145	24%
	196,188	184,817	11,372	6%	182,178	14,010	8%
Cost of Power							
Power Purchased	165,375	153,550	(11,825)	-8%	150,844	(14,530)	-10%
Total Cost of Power	165,375	153,550	(11,825)	-8%	150,844	(14,530)	-10%
Gross Profit Before Other Revenue	30,814	31,267	(453)	-1%	31,334	(520)	-2%
Expenses							
Operation and maintenance							
Distribution	6,488	6,167	(321)	-5%	6,532	44	1%
Utilization	204	234	30	13%	248	44	18%
Billing & Collecting	5,412	5,225	(187)	-4%	5,307	(105)	-2%
Administration & general	5,161	4,879	(282)	-6%	4,780	(380)	-8%
Depreciation	6,473	6,379	(94)	-1%	6,100	(373)	-6%
Depreciation on FMV adjustment of fixed assets	1,085	1,085	0	100%	1,089	4	0%
TOTAL EXPENSES	24,822	23,968	(854)	-4%	24,056	(766)	-3%
Income from operating activities	**5,991**	**7,299**	**(1,307)**	**-18%**	**7,278**	**(1,287)**	**-18%**
Finance income	100	100	0	0%	106	(6)	-5%
Finance costs	(2,436)	(2,286)	150	-7%	(2,524)	(88)	3%
Income before income taxes	**3,655**	**5,112**	**(1,457)**	**-28%**	**4,860**	**(1,204)**	**-25%**
Income tax expense	(1,297)	(1,612)	(315)	20%	(1,727)	430	-25%
Net Income for the year	**2,358**	**3,500**	**(1,142)**	**-33%**	**3,133**	**(774)**	**-25%**
Net movement in regulatory balances, net of tax	170	(115)	(285)	249%	1,105	(934)	-85%
Net income for the year, net movement in regulatory balances and comprehensive income	**2,529**	**3,386**	**(857)**	**-25%**	**4,237**	**(1,708)**	**-40%**

Statistics

	Projected 2016	Budget 2016	Projected vs Budget	Actual 2015	Projected 2016 vs Actual 2015
Cost of Power %	84.29%	83.08%	(1.21) pts	82.80%	(1.49) pts
Gross Profit % After Other Revenue	15.71%	16.92%	(1.21) pts	17.20%	(1.49) pts
Total Expenses as % of Total Revenue	12.65%	12.97%	0.32 pts	13.20%	0.55 pts
Net Income After Tax as % of Total Revenue	1.29%	1.83%	(0.54) pts	2.33%	(1.04) pts
Income Tax % of Net Income	35.48%	31.53%	3.95 pts	35.54%	(0.06) pts
Other Revenue	0.75%	0.70%	0.05 pts	0.94%	(0.19) pts
Distribution	3.31%	3.34%	0.03 pts	3.59%	0.28 pts
Utilization	0.10%	0.13%	0.02 pts	0.14%	0.03 pts
Billing & Collecting	2.76%	2.83%	0.07 pts	2.91%	0.15 pts
Administration & general	2.63%	2.64%	0.01 pts	2.62%	(0.01) pts
Depreciation	3.30%	3.45%	0.15 pts	3.35%	0.05 pts
Net finance costs	1.19%	1.18%	(0.01) pts	1.33%	0.14 pts

Niagara Peninsula Energy Inc.
Statement of Retained Earnings
for the year ending December 31, 2016
(000's)

	Projected 2016	Actual 2015
Retained Earnings, Beginning of Year	31,189	28,151
Net Income	2,529	4,237
Dividends on common shares	(1,400)	(1,200)
Retained Earnings, End of Period	**32,318**	**31,189**

Niagara Peninsula Energy Inc.
Statement of Cash Flows
For the year ending December 31, 2016

	Projected 2016 $	Actual 2015 $
Cash Provided By (Used In):		
Operations		
Net income and net movement in regulatory balances	2,529	4,237
Adjustments for:		
Depreciation and amortization	5,466	5,834
Depreciation and amortization intangible assets	290	266
Depreciation expense on fair market value adjustment of fixed assets	1,085	1,089
Amortization of deferred revenue	(758)	(613)
Employee future benefits	161	102
Interest expense	2,336	2,419
Employee's accumulated vested sick leave	(1)	2
Deferred tax expense	(0)	868
Current tax expense	0	859
	11,108	15,062
Changes in non-cash working capital components		
Accounts receivable	(1,879)	(1,119)
Due to/from related parties	11	(10)
Unbilled revenue	(1,299)	(921)
Materials and supplies	5	(18)
Prepaid expenses	46	(344)
Income tax receivable	326	(104)
Accounts payable and accrued liabilities	1,893	(708)
Customer deposits	(3)	39
Deferred revenue	357	374
	(544)	(2,812)
Regulatory balances	(974)	624
Interest paid	(2,436)	(2,524)
Interest received	100	106
Net cash from operating activities	7,255	10,456
Investing activities		
Purchase of property, plant and equipment	(14,698)	(14,839)
Purchase of intangible assets	(357)	(183)
Contributions received from customers	5,414	5,600
Net cash used by investing activities	**(9,640)**	**(9,421)**
Financing activities		
Dividends paid	(1,400)	(1,200)
Proceeds from long-term debt	20,000	2,250
Repayment of long-term debt	(1,420)	(3,628)
Net cash from financing activities	**17,180**	**(2,578)**
Change in cash and cash equivalents	14,794	(1,543)
Cash and cash equivalents, beginning of year	9,049	10,592
Cash and cash equivalents, end of year	23,843	9,049

Niagara Peninsula Energy
Projected Capital Budget
For the year ending December 31, 2016
(000's)

	Projected 2016	Original Budget 2016	Projected vs 2016 Budget Variance	Actual 2015	Projected 2016 vs 2015 Variance	2015 Test Year Approved in Rate App	Projected vs Test Year Variance
Land and Land Rights	0	0	0	0	0	0	0
Buildings & Fixtures	52	87	35	469	416	87	34
Sub Total	52	87	35	469	416	87	34
Distribution Station	0	0	0	1	1	0	0
Transformer Station	0	0	0	0	0	0	0
Overhead Distribution	6,000	4,633	(1,367)	5,219	(781)	4,505	(1,495)
Underground Distribution	5,407	4,292	(1,115)	5,550	143	3,514	(1,893)
Distribution Transformers	1,729	1,410	(319)	2,319	590	1,547	(182)
Meters	307	285	(22)	185	(123)	285	(23)
Smart Meters/MIST Meters	177	287	110	144	(33)	143	(33)
Sub Total	13,620	10,907	(2,713)	13,418	(202)	9,994	(3,625)
Office Furniture & Equipment	25	20	(5)	26	1	33	8
Computer Equipment, Hardware	248	242	(5)	249	1	240	(7)
Vehicles < 3 tonnes	75	90	15	236	161	114	39
Vehicles > 3 tonnes	725	690	(35)	254	(471)	514	(211)
Vehicles transportation other	75	60	(15)	0	(75)	71	(4)
Stores Equipment	0	0	0	55	55	0	0
Tools, Shop & Garage Equipment	119	70	(49)	67	(52)	61	(58)
Measurement & Testing Equipment	0	0	0	0	0	1	1
Communication equipment	306	150	(156)	66	(241)	215	(91)
Miscellaneous equipment	0	0	0	0	0	1	1
Sub Total	1,573	1,322	(250)	952	(621)	1,250	(323)
Total Capital before capital contributions	**15,245**	**12,316**	**(2,928)**	**14,839**	**(406)**	**11,331**	**(3,914)**
Capital Contributions	(5,417)	(800)	4,617	(5,600)	(184)	(828)	4,589
Net property plant & equipment	9,828	11,516	1,688	9,238	(590)	10,503	675
Intangible assets							
Computer Software	357	357	0	183	(174)	369	12
Total Intangibles	357	357	0	183	(174)	369	12
Total Gross Capital Expenditures	**10,185**	**11,873**	**1,688**	**9,421**	**(763)**	**10,872**	**687**
Vehicle Disposals	(547)	(498)	49	(504)	43	(314)	233
Net Captial Additions after disposals	**9,638**	**11,375**	**1,737**	**8,918**	**(720)**	**10,558**	**919**

Niagara Peninsula Energy
Budget Balance Sheet
As at December 31, 2017
(000's)

	Budget 2017	Projected 2016	$ Variance	% Variance	Actual 2015	$ Variance	% Variance
ASSETS							
Current Assets							
Cash	18,033	23,843	(5,810)	-24%	9,049	14,794	163%
Accounts Receivable	16,815	16,486	330	2%	14,607	1,879	13%
Unbilled Revenue	19,056	18,682	374	2%	17,383	1,299	7%
Payments in lieu of corporate taxes refundable	0	0	0	0%	306	(306)	-100%
Inventories	1,464	1,493	(30)	-2%	1,499	(5)	0%
Prepaid Expenses	1,120	1,067	53	5%	1,113	(46)	-4%
	56,488	**61,571**	**(5,083)**	**-8%**	**43,957**	**17,614**	**40%**
Fixed Assets							
Land and land rights	1,231	1,231	0	0%	1,231	0	0%
Buildings	17,676	17,483	193	1%	17,431	52	0%
Distribution Stations	9,583	9,383	200	2%	9,383	0	0%
Transformer Station	6,976	6,576	400	6%	6,576	0	0%
Distribution lines							
Overhead	120,723	115,420	5,304	5%	109,419	6,000	5%
Underground	109,527	106,698	2,829	3%	101,291	5,407	5%
Distribution transformers	47,079	45,657	1,422	3%	43,928	1,729	4%
Distribution meters	11,800	11,165	635	6%	10,681	484	5%
Trucks and Equipment	20,430	19,312	1,117	6%	18,286	1,026	6%
	345,023	332,924	12,099	4%	318,226	14,698	5%
Less: Accumulated Depreciation	(176,581)	(168,931)	(7,650)	5%	(162,380)	(6,551)	4%
	168,443	163,993	4,450	3%	155,846	8,147	5%
Intangible Assets							
Land rights	1,732	1,732	0	0%	1,732	0	0%
Computer Software	4,890	3,769	1,121	30%	3,412	357	10%
Total Intangible Assets	6,622	5,501	1,121	20%	5,144	357	7%
Less: Accumulated Depreciation intangible assets	(4,863)	(4,355)	(507)	12%	(4,065)	(290)	7%
	1,760	**1,146**	**614**	**54%**	**1,079**	**67**	**6%**
Total non-current assets	**170,202**	**165,139**	**5,063**	**3%**	**156,925**	**8,214**	**5%**
Regulatory balances							
Retail Cost Variances	306	224	82	37%	140	84	60%
Retail Settlement Variances	0	0	0	0%	4,646	(4,646)	-100%
Low Voltage Variances	1,796	1,165	631	54%	579	586	101%
Lost revenue adjustment mechanism	206	495	(289)		481	14	3%
Stranded Meters	5	224	(219)	-98%	880	(656)	-75%
Other Regulatory Assets	98	55	43	78%	36	19	52%
Regulatory related to income taxes	4,842	4,842	0	0%	4,842	0	0%
Deferral Change in Accounting Policy Depreciation	72	0	72	0%	0	0	100%
Deferral & Variance Recovery 2012 application	0	0	0	0%	250	(250)	-100%
Deferral & Variance Recovery 2014 application	119	119	0	0%	0	119	100%
Deferral & Variance Recovery 2015 COS application	20	12	8	62%	0	12	100%
	7,466	**7,138**	**328**	**5%**	**11,855**	**(4,717)**	**-40%**
Total assets and regulatory balances	**234,156**	**233,848**	**308**	**0%**	**212,737**	**21,111**	**10%**

Niagara Peninsula Energy
Budget Balance Sheet
As at December 31, 2017
(000's)

	Budget 2017	Projected 2016	$ Variance	% Variance	Actual 2015	$ Variance	% Variance
LIABILITIES							
Current Liabilities							
Accounts Payable	8,274	8,112	162	2%	8,878	(767)	-9%
Power bill payable	13,820	13,417	403	3%	10,758	2,660	25%
Taxes Payable	50	19	31	160%	0	19	100%
Due to related parties	18	18	0	0%	7	11	147%
Deferred OPA revenue & standard offer	787	1,187	(400)	-34%	831	357	43%
Customer Deposits	1,530	1,530	0	0%	1,533	(3)	0%
Current Portion of long term debt	1,514	1,466	48	3%	1,420	46	3%
Total current liabilities	**25,993**	**25,750**	**243**	**1%**	**23,427**	**2,323**	**10%**
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	51,461	52,975	(1,514)	-3%	34,442	18,534	54%
Employee Sick Leave Liability	45	51	(6)	-12%	52	(1)	-3%
Employee Future Benefits	2,815	2,665	150	6%	2,504	161	6%
Deferred Capital Contributions	35,006	33,469	1,537	5%	28,055	5,414	19%
Amortization capital contributions	(9,069)	(8,221)	(847)	10%	(7,463)	(758)	10%
Deferred tax liabilities	1,480	1,480	0	0%	1,480	(0)	0%
Total non-current liabilities	**107,344**	**108,024**	**(680)**	**-1%**	**84,674**	**23,350**	**28%**
Total liabilities	**133,338**	**133,775**	**(437)**	**0%**	**108,102**	**25,673**	**24%**
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	32,723	32,318	406	1%	31,189	1,129	4%
	89,428	**89,023**	**406**	**0%**	**87,894**	**1,129**	**1%**
TOTAL LIABILITIES & EQUITY	**222,766**	**222,797**	**(31)**	**0%**	**195,996**	**26,802**	**14%**
Regulatory Liabilities							
Retail Settlement Variances	7,343	7,246	97	1%	9,221	(1,976)	-21%
Other Regulatory Assets	1,571	1,571	0	0%	1,571	0	0%
Mist Meter Variance	50	88	(38)	-43%	44	44	101%
Smart Metering Entity Variance	37	37	0	0%	0	37	100%
Regulatory related to income taxes	764	764	0	0%	906	(142)	-16%
Deferral Change in Accounting Policy Depreciation	0	1,152	(1,152)	-100%	4,823	(3,671)	-76%
Deferral & Variance Recovery 2012 application	0	193	(193)	-100%	176	17	10%
Deferral & Variance Recovery 2016 COS application	1,625	0	1,625	100%	0	0	100%
	11,389	**11,050**	**339**	**3%**	**16,741**	**(5,691)**	-34%
Total liabilities, equity and regulatory liabilities	**234,156**	**233,848**	**308**	**0%**	**212,737**	**21,111**	**10%**

Niagara Peninsula Energy Inc.
Budgeted Statements of Operations
For the year ending December 31, 2017
(000's)

	Budget 2017	Projected 2016	2017 vs 2016 $ Variance	2017 vs 2016 % Variance	Actual 2015	2017 vs 2015 $ Variance	2017 vs 2015 % Variance	Rate Application Test Year	Budget 2017 vs Test Year	
SERVICE REVENUE										
Standard Supply Service	144,101	139,904	4,197	3%	127,172	16,929	13%	120,621	23,480	19.47%
Wholesale, Network & Connection Charges	25,787	25,471	316	1%	23,682	2,104	9%	23,529	2,258	9.60%
Service Charge	16,987	14,921	2,066	14%	14,010	2,976	21%	14,897	2,090	14.03%
Distribution Volumetric Charge	11,772	13,479	(1,707)	-13%	14,803	(3,030)	-20%	13,901	(2,129)	-15.31%
Standard Supply Service Admin Charge	156	146	11	7%	149	7	5%	147	10	6.64%
Retailer Revenue	35	35	(1)	-2%	39	(4)	-11%	45	(11)	-23.55%
Other Revenue	1,390	1,475	(85)	-6%	1,709	(319)	-19%	1,349	41	3.02%
Capital Contributions	847	758	89	12%	613	234	38%	800	47	5.92%
	201,076	196,188	4,887	2%	182,178	18,897	10%	175,289	25,786	14.71%
Cost of Power										
Power Purchased	169,888	165,375	(4,513)	-3%	150,844	(19,044)	-13%	144,150	(25,738)	-17.86%
	169,888	165,375	(4,513)	-3%	150,844	(19,044)	-13%	144,150	(25,738)	-17.86%
Gross Profit Before Other Revenue	**31,188**	**30,814**	**374**	**1%**	**31,334**	**(146)**	**0%**	**31,140**	**48**	**0.15%**
Expenses										
Operation and maintenance										
Distribution	6,694	6,488	(206)	-3%	6,532	(162)	-2%	6,521	(173)	-2.65%
Utilization	264	204	(60)	-30%	248	(17)	-7%	169	(96)	-56.69%
Billing & Collecting	5,487	5,412	(74)	-1%	5,307	(180)	-3%	5,249	(238)	-4.53%
Administration & general	5,226	5,161	(65)	-1%	4,780	(446)	-9%	4,486	(740)	-16.48%
Depreciation	7,107	6,473	(634)	-10%	6,100	(1,007)	-17%	5,834	(1,273)	-21.82%
Depreciation on FMV adjustment of fixed assets	1,051	1,085	34	3%	1,089	38	4%	0	(1,051)	0.00%
TOTAL EXPENSES	**25,828**	**24,822**	**(1,006)**	**-4%**	**24,056**	**(1,773)**	**-7%**	**22,259**	**(3,569)**	**-16.04%**
Income from operating activities	**5,359**	**5,991**	**(632)**	**-11%**	**7,278**	**(1,919)**	**-26%**	**8,881**	(3,521)	-39.65%
Finance income	192	100	92	92%	106	86	82%	100	92	92.00%
Finance costs	(2,727)	(2,436)	(291)	12%	(2,524)	(203)	8%	(3,296)	569	-17.26%
Income before income taxes	**2,824**	**3,655**	**(831)**	**-23%**	**4,860**	**(2,035)**	**-42%**	**5,685**	**(2,860)**	**-50.32%**
Income tax expense	(1,030)	(1,297)	267	-21%	(1,727)	697	-40%	(168)	**(862)**	512.37%
Net Income for the year	**1,794**	**2,358**	**(564)**	**-24%**	**3,133**	**(1,338)**	**-43%**	**5,516**	**(3,722)**	**-67.47%**
Net movement in regulatory balances, net of tax	11	170	(159)	-93%	1,105	(1,093)	-99%	0	11	100.00%
Net income for the year, net movement in regulatory balances and comprehensive income	**1,806**	**2,529**	**(723)**	**-29%**	**4,237**	**(2,431)**	**-57%**	**5,516**	**(3,711)**	**-67.27%**
Other comprehensive income for the year	0	0	0	0%	0	0	0%	0	0	**0**
Total comprehensive income for the year	**1,806**	**2,529**	**(723)**	**-29%**	**4,237**	**(2,431)**	**-57%**	**5,516**	**(3,711)**	**-67.27%**

Niagara Peninsula Energy Inc.
Statement of Retained Earnings
for the year ending December 31, 2017
(000's)

	Budget 2017	Projected 2016	Actual 2015
Retained Earnings, Beginning of Year	32,318	31,189	28,151
Net Income	1,806	2,529	4,237
Dividends on common shares	(1,400)	(1,400)	(1,200)
Retained Earnings, End of Period	**32,723**	**32,318**	**31,189**

Niagara Peninsula Energy Inc.
Statement of Cash Flows
For the year ending December 31, 2017

	Budget 2017 $	**Projected 2016 $**	**Actual 2015 $**
Cash Provided By (Used In):			
Operations			
Net income and net movement in regulatory balances	1,806	2,529	4,237
Adjustments for:			
Depreciation and amortization	6,600	5,466	5,834
Depreciation and amortization intangible assets	507	290	266
Depreciation expense on fair market value adjustment of fixed assets	1,051	1,085	1,089
Amortization of deferred revenue	(847)	(758)	(613)
Employee future benefits	150	161	102
Interest expense	2,535	2,336	2,419
Employee's accumulated vested sick leave	(6)	(1)	2
Deferred tax expense	0	(0)	868
Current tax expense	0	0	859
	11,796	11,108	15,062
Changes in non-cash working capital components			
Accounts receivable	(330)	(1,879)	(1,119)
Due to/from related parties	0	11	(10)
Unbilled revenue	(374)	(1,299)	(921)
Materials and supplies	30	5	(18)
Prepaid expenses	(53)	46	(344)
Income tax receivable	31	326	(104)
Accounts payable and accrued liabilities	565	1,893	(708)
Customer deposits	0	(3)	39
Deferred revenue	(400)	357	374
	(531)	(544)	(2,812)
Regulatory balances	11	(974)	624
Interest paid	(2,727)	(2,436)	(2,524)
Interest received	192	100	106
Net cash from operating activities	8,740	7,255	10,456
Investing activities			
Purchase of property, plant and equipment	(12,099)	(14,698)	(14,839)
Purchase of intangible assets	(1,121)	(357)	(183)
Contributions received from customers	1,537	5,414	5,600
Net cash used by investing activities	**(11,683)**	**(9,640)**	**(9,421)**
Financing activities			
Dividends paid	(1,400)	(1,400)	(1,200)
Proceeds from long-term debt	0	20,000	2,250
Repayment of long-term debt	(1,466)	(1,420)	(3,628)
Net cash from financing activities	**(2,866)**	**17,180**	**(2,578)**
Change in cash and cash equivalents	(5,809)	14,794	(1,543)
Cash and cash equivalents, beginning of year	23,843	9,049	10,592
Cash and cash equivalents, end of year	**18,033**	**23,843**	**9,049**

Niagara Peninsula Energy Inc.
Capital Budget 2017
For the year ending December 31, 2017
(000's)

	Appendix	Proposed Budget 2017	Projected 2016	Proposed Budget 2016 vs Projected 2016 Variance	Actual 2015	Test Year Approved in Rate App
Land and Land Rights	A	0	0	0	0	0
Buildings & Fixtures	A	193	52	140	469	87
Sub Total		193	52	140	469	87
Distribution Station	B	200	0	200	1	0
Transformer Station	B	400	0	400	0	0
Overhead Distribution	B	5,304	6,000	(696)	5,219	4,505
Underground Distribution	B	2,829	5,407	(2,578)	5,550	3,514
Distribution Transformers	B	1,422	1,729	(307)	2,319	1,547
Meters	B	435	307	128	185	285
Smart Meters	B	200	177	23	144	143
Sub Total		10,789	13,620	(2,830)	13,418	9,994
Office Furniture & Equipment	C	20	25	(5)	26	33
Computer Equipment, Hardware	D	401	248	154	249	240
Vehicles < 3 tonnes	F	180	75	105	236	114
Vehicles > 3 tonnes	F	515	725	(210)	254	514
Vehicles Transportation Other	F	0	75	(75)	0	71
Stores Equipment		0	0	0	55	0
Tools, Shop & Garage Equipment	G	82	119	(37)	67	61
Measurement & Testing Equipment		0	0	0	0	1
Communication equipment	H	300	306	(6)	66	215
Miscellaneous equipment		0	0	0	0	1
Sub Total		1,499	1,573	(74)	952	1,250
Total Capital before capital contributions		**12,480**	**15,245**	**(2,764)**	**14,839**	**11,331**
Capital Contributions	B	(1,537)	(5,417)	3,880	(5,600)	(828)
Net property plant & equipment		10,943	9,828	1,115	9,238	10,503
Intangible assets						
Computer Software	E	1,121	357	764	183	369
Total Intangibles		1,121	357	764	183	369
Total Gross Capital Expenditures including Capital Contributions		**12,064**	**10,185**	**1,879**	**9,421**	**10,872**
Vehicle Disposals		(381)	(547)	165	(504)	(314)
Net Captial Additions after disposals		**11,683**	**9,638**	**2,045**	**8,918**	**10,558**

APPENDIX A

Building 2017

	2017 Budget
Building	
Rate Application	
Front Entrance - Drop Box redesign	10,000
Tool Room Racking	5,000
Front Gate Opener	4,500
Replace Rooftop Heat/AC Units	23,000
Architect, Civil, Mechanical Office Bldg for Control Room and Garage	150,000
Total	**192,500**

APPENDIX B
List of Projects

Item	Project	Gross Capital Investment	Capital Contribution	Net Capital Investment
1	Dorchester - McLeod to Dunn Phase 2	359,131	0	359,131
2	Oakwood Drive - Overhead replacement -*deferred from 2016*	600,819	0	600,819
3	Padmount Switchgear replacement program	250,000	0	250,000
4	Station #14 Voltage Conversion Phase I	589,623	0	589,623
5	Brown Road extension - Montrose to Blackburn	189,664	0	189,664
6	Subdivision Rehabilitation Allowance	245,151	0	245,151
7	Additional sectionalizing switches	73,000	0	73,000
8	Victoria Avenue Fly Road South PH 1- *deferred from 2016*	308,719	0	308,719
9	1-Phase Hydraulic Reclosure Upgrades	100,000	0	100,000
10	Jordan Road Voltage Conversion Phase IV	561,614	0	561,614
11	Downtown Core PILCDSTA De-commissioning	292,171	0	292,171
12	Dorchester Mountain to Riall - *deferred from 2016*	678,670	0	678,670
13	Lightning Mitigation Measures	30,000	0	30,000
14	Chippawa Redundant Supply Upgrades Phase I	343,719	0	343,719
15	Heartland Road extension-Brown Road to Chippawa Creek	114,583	0	114,583
16	Station DS Power Transformer Replacement	200,000	0	200,000
17	Kalar TS Protection-Relay Upgrades	400,000	0	400,000
18	Line Relocations due to Municipal Road Improvements	500,000	(200,000)	300,000
19	Replacement of Poles identified with Structural Integrity	626,236	0	626,236
20	Kiosk replacement program	1,001,137	0	1,001,137
21	System Sustainment allowance	820,000	0	820,000
22	Subdivision Lot servicing of existing lots	275,000	(275,000)	0
23	Connection and energizing of new subdivisions	312,004	(312,004)	0
24	Subdivision Lot Rebates- new connections	250,000	0	250,000
25	Customer Demand Work	1,124,500	(750,000)	374,500
26	Metering - General	343,500	0	343,500
27	Metering - MIST	200,000	0	200,000
		10,789,240	**(1,537,004)**	**9,252,236**

Total Labour	3,951,808
Total Truck	1,071,241
Total Material	3,382,916
Total AP	2,383,276
Total before Contributions	10,789,240

PROPOSED N.P.E.I 2017 CAPITAL BUDGET PROGRAM

As in previous years, the NPEI 2017 Capital Budget will continue 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 cyclic 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.

Expansions and Reinforcement of the N.P.E.I. 13.8 K.V. / 27.6 K.V. Primary Distribution System to accommodate load growth & reliability requirements.

1. **Dorchester Road—McLeod Road to Dunn Street** **Investment Category SR**

Complete the overhead work that was started in 2016. Rebuild Project targeting 1.0 km of urban distribution line installed in 1955, including 26 pole changes, new three phase (1.0km) primary and secondary (1.0km) circuits, 5-1ph & 3-3ph distribution transformer replacements resulting in upgraded supply to about 74 residential and 7 commercial customers directly. System benefits include replacement of aging equipment, future source for voltage conversions opportunities in the immediate area, improved equipment clearance and increased customer reliability and capacity increase.

Estimated Cost = $ 359,131.41 remaining of $531,912 **–**
NF Service Area Project #2017-0001

2. Oakwood Drive--Pole #111-25 to Pole #98-7 **Investment Category SS**

Project scope involves replacement of 1.5 KM. of an urban overhead primary distribution line, with an overhead 15 KV 600 amp class main 3-phase line in the same alignment as the existing. Installation of 25-new 50' wood poles, 7-Single Phase, 2-Three Phase transformers, transfer 3-three phase & 1-Single Phase Underground Primary Risers, and transfer 24-existing Residential triplex services. Since the original install this section of line has changed function from a radial feed, and has been incorporated into a tie between 2-Transformer Stations, without re-conductoring to facilitate the ampacity increase. System benefits include the replacement of aging equipment originally installed in 1970, system loss reduction, improved reliability, and capacity increase.

Estimated Cost= $ 600,819.05 ***-- NF Service Area Project #2017-0002***

3. **Pad-mounted Switchgear Replacements** **Investment Category SR**

The Underground Equipment Inspection Program has identified a requirement for replacement of air insulated pad-mounted switchgear units, with dead-front stainless steel enclosure SF-6 Gas Insulated Equipment, due to corrosion and contamination issues, which will continue at a rate of 3-Units per year. 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= $ 250,000.00 ***-- NF Service Area Project #2017-0006***

4. ***Overhead line rebuilds of facilities identified by the Pole Inspection Survey. Category SR***

This Capital Program targets overhead distribution facilities identified at end of life, determined from results of the Pole Testing Program. Existing overhead distribution equipment at these locations, are replaced with new overhead facilities incorporating new poles, conductors and transformers to maximize efficiency, reliability and the ability for conversion to a higher distribution voltage as warranted. For 2017 this program targets the first phase of a 3-year program to eliminate station #14 starting with the rebuild and conversion of Dunn Street between Drummond Road and Dorchester Road.

- **Station #14--Voltage Conversion Phase I** **Investment Category SR**

Rebuild Project which targets 1.20 kilometers of urban distribution line installed in 1956, including 34 pole changes, new three-phase (1.2KM) & secondary (1.2KM) circuits, 8-single & 2-Three phase distribution transformer replacements resulting in the upgraded supply to about 86 residential & 2-commercial customers directly, in the area bounded by Dunn St from Dorchester Rd to Drummond Road. System benefits include reconstruction to eliminate Municipal Sub-station 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: $ 589,622.99 ***-- NF Service Area Project #2017-0007***

5. **Brown Road Extension--Montrose to Blackburn** **Investment Category SS**

Project scope involves extension of 1.2 KM. of an urban overhead primary distribution line, overbuilt on a wooden pole line built by Bell Canada in 2008 at which time NPEI had Bell install 13-poles with additional height from 35' to 45'. The framing & stringing of this section of line will be incorporated into a tie between 2-previous line builds to service a new low lift pumping station and an Industrial Subdivision owned by the City of Niagara Falls. System benefits include improved reliability, inter-tie capabilities between the K-M-6 & K-M-2 Feeders sourced from the Kalar M.T.S and the 3-M-30 from Murray T.S...

Estimated Cost= $ 189,663.65 ***-- NF Service Area Project #2017-0008***

6. **Subdivision Rehabilitation Allowance.** **Investment Category SS**

Establishment of this Capital Program provides 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. The original installations were duct-less, making replacement difficult and costly. To extend lifecycles of the infrastructure NPEI recently completed a Program to replace the Submersible Transformers with Pad-mount Transformers. The program began in 1994 with approximately 400 units converted. Sections of primary cable within the submersible enclosure, damaged by poor heat dissipation were spliced out and re-terminated, preventing failure. The cable was manufactured to a 133% insulation level, prolonging the life cycle; however, without a base value to compare the results of any cable testing, it is difficult to determine degradation since its installation. Expected lifespan of the cable is 35 years. To correct a noted deficiency in last Asset

Subdivision rehabilitation allowance continued:

Assessment NPEI has entered installation dates, within the GIS, from as-built drawings, to help in prioritizing future replacement. The program would facilitate the installation, by directional boring methods, of a 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 under the Sustainment budget. The first subdivision targeted was installed in 1967.

Estimated cost: $245,150.50 ***-- NF Service Area Project #2017-0009***

7. **Additional Sectionalizing Switches—8-Units** **Investment Category SR**

   A review of existing feeder configurations, sourced by Stanley, Murray, Beamsville & Niagara West Transformer Stations , Kalar M.T.S. and Vineland D.S., utilizing system optimization software, has identified a need for additional pole mounted ganged load break switches within the system, minimizing system losses, providing improved contingency options during outage events, providing a means to minimize the area affected. The program will target the installation of 8 additional units.

   Estimated Cost= $ 73,000.00 ***-- Combined Service Area Project #2017-0010***

8. **Victoria Avenue Fly Rd South Ext Phase I.** **Investment Category SS**

   The Project Scope involves the overbuild of an existing 3-phase 8.2 KV primary line on Victoria Ave in place, and constructed with a 3-phase 27.6KV top circuit for approximately 2.0 KM. Construction involves the installation of 32-new 45' poles, transfer of existing primary cable, and installation of 2.0 km of new 556 MCM Primary and Neutral conductor from Fly Rd South to Seventh Ave. The Project is being initiated to provide a 27.6KV tie to town of Jordan Station Benefits include improved supply reliability and flexibility on the system during contingencies & system configuration by tying the F-1 Feeder from Vineland D.S to the M-5 Feeder from NWMTS. .

   Estimated Cost = $ 308,719.21 ***-- PW Service Area Project #2017-0012***

9. **1-Phase Hydraulic Reclosure Upgrades—10-Units** **Investment Category SS**

   Approaching end of life cycles, and relating to the 5-year Wi-Max deployment plan, a requirement has been identified, for the replacement of 10-existing pole mounted hydraulic reclosures. There are approximately 90 oil filled units in service on the system. 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. The solid dielectric insulation eliminates the oil used in the older units, making them less of an environmental concern.

   Estimated Cost= $ 100,000.00 ***-- PW Service Area Project #2017-0013***

10. ***Jordan Road—Voltage Conversion Phase IV*** ***Investment Category SR***

    The Project Scope involves the last stage of rebuild of existing 3-phase 8320Volt primary line, in place, constructed to 27.6KV standards for approximately 2.0 KM involving the installation of 34-new 45' poles on Honsberger Rd from Jordan Rd to Thirteenth St., transfer of existing primary conductors, and installation of 2.0km of new neutral. The project was driven by the pole inspection program which has

Jordan Road—Voltage Conversion Phase IV continued
identified a high number of deteriorated cross arms supporting the primary conductors. Benefits include elimination of the identified hazard, improved equipment clearance, and conversion to 27.6KV of the feeders supplied by Jordan M.S. for its de-commissioning.
Estimated Cost = $ 561,613.62 ***-- PW Service Area Project #2017-0015***

11. **Downtown Core PILCDSTA De-Commissioning** **Investment Category SS**
Complete the overhead work that was carried over from 2016. NPEI has targeted lead jacketed primary cable for removal from service due to age (installed in 1959), performance and difficulty of performing repairs. The last section in service is located between Station #151 on River Rd and the City Hall Sub-Station located on Huron St.
Estimated Cost = $ 292,170.69 remaining of original $795,701
-- NF Service Area Project #2017-0017

12. **Dorchester Road-- Mountain Road Riall Street** **Investment Category SS**
Project scope involves the replacement of 1.0 KM. of urban overhead 13.8 KV primary line installed in 1952 with 20-new 45' wood poles, constructed in the same alignment as the existing pole line, install of 200m of concrete encased duct-bank under a major Transmission Corridor due to clearance issues with the transmission line to an overhead line. Replacement of the undersized primary conductor with 556 MCM for increased ampacity of the circuit during contingency situations, 4-single phase transformers to replace existing, install 0.6KM of secondary buss, and transfer of 40 services to the new buss. Benefits include improved system losses, improved equipment clearances, reinforcement & capacity increase of the supply in the area.
Estimated Cost= $ 678,669.75 ***--NF Service Area—Project #2017-0018***

13. **Lightning Mitigation Measures-** **Investment Category SS**
The continuation of an established sustainment Program, the project scope involves the installation of additional lightning mitigation equipment throughout the distribution system within the Western Service Territory to correct deficiencies identified through recent storm related equipment failure events. Benefits include improved reliability indices, reduction in the amount of equipment damaged during storm events, improved outage restoration times.
Estimated Cost = $ 30,000.00 ***-PW Service Area —Project #2017-0019***

14. Chippawa Redundant Supply Upgrades Phase I **Investment Category SS**
Phase I of the two part Project scope involves rebuild/reinforcement of 1.4 KM. of an existing rural overhead primary distribution line, on Stanley Ave from Lyons Creek Rd to Rexinger Rd, Rexinger Road from Stanley Ave to Ort Rd--Ort Rd from Rexinger Rd to Willick Rd, incorporating 12-new pole installs and salvaging poles upgraded by the Pole Replacement Program. NPEI will re-conductor the existing 1/0 Aluminum Primary with 556 MCM Aluminum for the required capacity increases. This Project will enable NPEI to target the removal of a sub-standard aerial primary Welland River Crossing feeding into the Village of Chippawa. System benefits include improved reliability, inter-tie capabilities between the 3-M-27 & 3-M-56 Feeders sourced from the Murray T.S.
Estimated Cost= $ 343,718.74 ***-- NF Service Area Project #2017-0022***

15. Heartland Road Extension--Brown Rd to Chippawa Creek Rd- Category SS

Project scope involves extension of 0.4 KM. of an urban overhead primary distribution line, including the installation of 8 new 45' poles, framing & stringing of 556 MCM primary conductor to tie between 2-previous line builds to service a new low lift pumping station and a Regional Bio-Solids Treatment facility. System benefits include improved reliability, inter-tie capabilities between the K-M-6 & K-M-2 Feeders sourced from the Kalar M.T.S and the 3-M-30 from Murray T.S...

Estimated Cost= $ 114,582.52 -- NF Service Area Project #2017-0023

16. Station Street D.S. Transformer Replacement Investment Category SR

Project scope involves removal, transportation, and replacement of the 5000 KVA Power Transformer located at the Distribution Sub-Station. Under previous refurbishments the switchgear line-up and supply cables were upgraded, and the compound is equipped with an oil containment structure. The Station is one of two stations supplying the Town of Fonthill at 4.16KV without provisions for voltage conversion, due to Hydro One controlled supply points. The Station Transformer was manufactured in 1969.

Estimated Cost= $ 200,000.00 --PW Service Area—Project #2017-0024

17. Kalar T.S.Protective Relaying Upgrades Investment Category SS

Project scope involves Upgrade of Protective Relaying/Communication Equipment in conjunction with upgrades which are currently underway by Hydro One at the Allanburg facility.

Estimated Cost= $ 400,000.00 --NF Service Area—Project #2017-0025

18. Line Relocations due to Municipal Road Improvement requirements. Category SA

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: $500,000.00 (Recoverable $200,000) -- Combined Service Area

19. Replacement of Poles identified with limited Structural Integrity. Category SR

The natural degradation of wooden utility poles is an ongoing issue. Per the Distribution System Code, 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 was performed, with deficiencies addressed by the replacement of subject poles, in a timely manner, through this Capital Program. In the Niagara Area pole replacements are beginning to level off as cycles begin to repeat, with a structured treatment program implemented

Replacement of Poles identified with limited Structural Integrity continued

during the testing cycle to increase the poles life cycle. The 2016 Niagara test area is bounded in the West by the Welland City Limits, South to the Fort Erie City Limits, East to the Niagara River, and North to the Welland River, and includes 2500 poles total. The Western Service Territory test area is bounded by Regional Road #20/#27 to the west, north to Fly Road, East to Victoria Avenue, south to the Boundary line at East Chippawa Road, and includes 4000 poles. The average cost per pole change is approximately $ 5,000.
Estimated Costs: $ 626,235.95-Combined Service Area -Project #2017-1010/2010

20. Replacement of Kiosks with Transformers, EFD & Posi-tect Switches Category SR

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 2013.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. 49-Units remain on the 15KV System, and 56-Units remain on the 5KV System. For 2017 the plan is to replace 10 to 15 units.
Estimated cost: $1,001,137.39 -- NF Service Area Project #2017-0020

21. System Sustainment Allowance. Investment Category SS

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: $ 820,000.0-- Combined Service Area-- Project #2017-1007/2007

22. Subdivisions and New Residential Services Investment Category SA

Estimated cost: Lot servicing of existing	***$275,000.00***
Recoverable	***($275,000.00)***
23. Connection and energizing of new subs	***$312,004.30***
Recoverable	***($312,004.30)***
24. Lot connection rebates	***$250,000.00***

25. Demand Based System Reinforcements for New Commercial Service Connections. Investment Category SA

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: $1,124,500.00 –Combined Area-- Project #2017-1008/2008 (Recoverable $750,000.00)

26. *Metering General* ***$343,500.00***

27. MIST Meters ***$200.000.00***

Project Total	***$ 10,789,239.77***
Recoverable	***($ 1,537,004.30)***
TOTAL	***$ 9,252,235.47***

APPENDIX C

General Equipment - 2017

	2017 Budget
Ergonomic Office Equipment	9,000
General Equipment as needed	11,000
	20,000

APPENDIX D

Hardware - 2017

Function	Item	Purpose	Project	Total
Network	2 x 24 Port Nortel switch	Hyperconvergence	Network Infrastructure	$ 30,000.00
	24 Port Nortel switch	Hot Spare - Data	Network Infrastructure	$ 30,000.00
Hyperconvergence Virtual Servers & Physical Servers	LT04 Library Backup Solution for Smithville - physical	Improved backup system from using tape	Disaster Recovery/End of life	$ 12,000.00
	Server - physical	Backup server for Smithville	End of life	$ 12,000.00
	Server - physical	Migration server for OMS - Primary	End of life	$ 20,000.00
	Hyperconvergence servers	Node 3 and 4	Hyperconvergence model - each node allows for placement of 20 existing servers; primary node and redundancy node+ room for growth	$ 166,000.00
	Equallogic SAN for Smithville	Extra storage for Smithville	End of life	$ 60,000.00
Printers	Replacement of HP printer		Replacement due to age and usage	$ 2,500.00
	Replacement of T620	Replacement of current T620	Replacement due to age and usage	$ 2,500.00
	Lexmark	Report printer	Replacement due to age and usage	$ 2,500.00
	Lexmark	Printer for Barb K	Upgrade due	$ 650.00
	Lexmark	Printer	Replacement for receipt printer	$ 400.00
	Fijutsu	Scanner for accounting area	New requirement for integration of File Nexus into Finance	$ 700.00
	Plotter	Replacement of Smithville	Upgrade due	$ 15,000.00
Phones	Mitel Cordless Handset & Mod Bundle for phone in Control room	Cordless handset for ease of answering the call regardless of user location	Upgrade due	$ 440.00
	Office phones required (3 5330 IP phone (backlit) + UC Basic User (3 license) + Professional services)	Add as required		$ 1,200.00
Cell phones			Replacement as required	$1,500.00

Function	Item	Purpose	Project	Total
PC / Monitor	PC and Monitor Replacements	Add PCs and monitors as required	Replacement due to age and usage as required and new hires; global PC in Smithville for employees to view intranet; one large monitor in cashier balancing room, larger monitor on arms for cashiers; new monitor to show security to customers (possible re-use of monitor being replaced by a larger monitor.)	$ 10,000.00
	Motorola 810	Deployment of Inservice field use in Operations, and mcare in Metering	Deployment of field laptops for Mcare and Integraph Inservice product; upgrade due; however, all are operational	$ 20,000.00
Security cameras	Security Cameras	Camera by money box	Camera and install of camera closer to money box; *possible redesign of where money box is moved*	$ 10,000.00
LCD Projectors	NEC VT595 XGA 2000 ANSI LUNCENS PROJECTORS	Niagara Falls and West Lincoln Training Room LCD Projectors (not mounted)	Replacement as required	$ 1,000.00
Charging Station				$ 3,000.00
TOTAL HARDWARE				**$ 401,390.00**

APPENDIX E

Software - 2017

Department	Project	Description	Purpose	Amount
Engineering	Work Management/Outage Management Intergraph solution including software and professional services for upgrade including Oracle licensing	OMS upgrade including call taker, mobile component - utilizing Oracle standard	Upgrade due	$260,000
Engineering	Oracle standard to enterprise effort, if required	Oracle upgrade	Upgrade required for new version of OMS	$15,000
Engineering/Operations /Billing	OMS/CIS interface	Allows one entry of call to flow from/to OMS and CIS	New requirement; business process improvement	$35,000
Engineering/Operations	AMI ping within OMS; broadcast to email and social media	API used to test multi speak connection between OMS and AMI; same API used to broadcast confirmed outages to email and social media, ie. Twitter		$89,000
Engineering/Operations	AMI ping within OMS; broadcast to email and social media	Professional services to install, configure and train on the API used to test multi speak connection between OMS and AMI; same API used to broadcast confirmed outages to email and social media, ie. Twitter		$41,000
Engineering	G/Tech license	Additional license required	Usage to date results in frequent users not being able to log in	$ 27,500.00
Engineering	Dispatcher license	Additional license required	Compliance to users on system; will use iViewer for the remaining users that need to log in	$ 28,300.00
Engineering	Sustainable Engineering hours	Professional services for fixes not covered by maintenance		$ 10,000.00
Engineering / Operations	Service Location Request/SPOT	Purchase or development of spot replacement	Prototype created to generate requirements in 2016; will review prototype to what is available in market	$ 66,500.00
Operations	Electronic Material Movement Sheet		Need to explore whether we can rollout existing product and whether this can be done internally;	$ 15,000.00
Operations	Managers Plus	Professional services	If we can complete internally for rollout to organization, then professional services will not be required.	$ 10,000.00
Human Resources	Intranet	Employee interactive portal to publish vacation, policies, forms, ability to handle email blasts; available internally and through browser	$30,000 for software and development; $6,000 for license	$ 36,000.00
Human Resources	Forms	Professional services and training to complete forms: accident/incident; benefit forms; safety suggestion form; workflow to complete all other forms found in HR and executive office	New requirement; business process improvement; training	$ 11,000.00
Finance	Upgrade of Great Plains due	Upgrade	Upgrade due	$ 35,000.00

Department	Project	Description	Purpose	Amount
Finance	eConnect	Interface software	Professional services for business process improvement	$ 10,000.00
Finance	Payroll updates	Required update	Required update; 1500.00 x 2	$ 3,000.00
Finance	Power BI	Professional services	Professional services for business process improvement; software being purchased in 2016	$ 10,000.00
Finance / HR	Vacation Workflow intelligence	Software and workflow development	Vacation workflow from entry based on what is available, tracking of changes, interfaced to GP payroll, and available in form entry and view to employee via intranet. Track changes between use of vacation versus float days.	$ 35,000.00
Finance / HR	Who's Where 3.0	Professional services	Ability to track use of vacation, float day, sick day, appointment on timesheet; rollout of timesheet to organization	$ 5,000.00
Finance	Excel 2013		Finance and IT support staff new requirement	$ 2,000.00
Customer Service / Billing	Harris Northstar Professional Services	New requirement	Regulatory changes as required; ie. Net metering, change of contacts layout for customer engagement, next phase of automation platform	$ 50,000.00
Customer Service / Billing	Harris Northstar Professional Services / Outsource partner	New requirement	Bill presentment - if needed dependent on regulations	$ 25,000.00
All	Website	Upgrade	$30,000 for development; $6000 for licensing	$ 36,000.00
All	Upgrade of File Nexus	Professional services	Conversion of Engineering documents	$ 15,000.00
All	ANTI VIRUS PROTECTION APPLIANCE		New appliance required to scan documents within the network; mitigation of zepto virus	$ 75,000.00
IT Services Shared				$ 175,560.00
TOTAL SOFTWARE				**$1,120,860**

APPENDIX F

Vehicles and Transportation Other Equipment 2017

Description	2017 Budget
Vehicles < 3 tonnes	
Electric Vehicle	40,000
Replace NF#59 Supervisor Pickup	45,000
Replace NF#53 Lead Hand Pickup	40,000
Replace NF#57 Lead Hand Pickup	40,000
Lead Hand Vehicles equipment	11,000
Replace Power-lift gate for Maintenance Vehicle	4,250
Total	180,250

Vehicles > 3 tonnes	2017 Budget
Replace NF#42 Single Bucket	290,000
Replace NF#25 Broderson Crane(1989)	225,000
	515,000
Total	695,250

APPENDIX G

Tools Budget 2017

Tools and Equipment for Vehicles	2017 Budget
New tools for new budgeted trucks	15,000
Miscellaneous Replacement Tools	56,000
	71,000

Tools for Garage	
Various other shop tools	11,000
Total tools for garage	11,000
Total Tool Budget	82,000

APPENDIX H

Communication Equipment - 2017

	2017 Budget
Wi-max project-Niagara Falls Tower	300,000
Total	**300,000**

Niagara Peninsula Energy Inc.
Capital Budget 2011 - 2019
(000's)

	Actual 2011	Actual 2012	Actual 2013	Actual 2014	Actual 2015	Projected 2016	Proposed Budget 2017	2018	2019	2020	2021
Land and Land Rights	0	5	1	0	0	0	0	0	0	0	0
Buildings & Fixtures	122	626	1,912	1,613	469	52	193	750	600	50	50
Sub Total	122	631	1,913	1,613	469	52	193	750	600	50	50
Distribution Station	800	684	501	514	1	0	200	0	0	0	0
Transformer Station	0	0	0	16	0	0	400	0	0	0	0
Overhead Distribution	3,912	3,663	4,786	4,362	5,219	6,000	5,304	5,262	5,471	5,474	5,451
Underground Distribution	2,783	3,148	2,476	3,470	5,550	5,407	2,829	3,654	3,210	2,805	3,250
Distribution Transformers	1,064	1,247	1,371	1,135	2,319	1,729	1,422	1,505	1,481	1,355	1,340
Meters	177	171	193	396	185	307	435	435	435	435	435
Smart Meters/MIST meters	615	786	82	2,049	144	177	200	200	200	200	0
Sub Total	9,351	9,699	9,409	11,942	13,418	13,620	10,789	11,056	10,797	10,269	10,476
Office Furniture & Equipment	69	112	170	177	26	25	20	50	100	20	20
Computer Equipment, Hardware	250	371	276	279	249	248	401	246	241	285	285
Vehicles < 3 tonnes	350	104	158	0	236	75	180	111	142	150	150
Vehicles > 3 tonnes	189	1,057	1,172	631	254	725	515	637	442	500	500
Vehicle Other	0	0	0	21	0	75	0	0	22	0	0
Stores Equipment	10	55	0	32	55	0	0	0	0	0	0
Tools, Shop & Garage Equipment	78	133	83	60	67	119	82	75	75	75	75
Measurement & Testing Equipment	15	0	0	0	0	0	0	0	0	0	0
Communication equipment	1	332	344	228	66	306	300	250	150	100	0
Miscellaneous equipment	0	0	0	0	0	0	0	0	0	0	0
Sub Total	962	2,163	2,203	1,428	952	1,573	1,499	1,369	1,171	1,130	1,030
Total Capital before capital contributions	**10,435**	**12,493**	**13,525**	**14,983**	**14,839**	**15,245**	**12,480**	**13,175**	**12,568**	**11,449**	**11,556**
Capital Contributions	(1,664)	(1,585)	(991)	(1,388)	(5,600)	(5,417)	(1,537)	(1,537)	(1,537)	(1,537)	(1,537)
Net property plant & equipment	**8,771**	**10,908**	**12,534**	**13,595**	**9,238**	**9,828**	**10,943**	**11,638**	**11,031**	**9,912**	**10,019**
Intangible assets											
Computer Software	194	213	115	538	183	357	1,121	281	453	500	400
Total Intangibles	**194**	**213**	**115**	**538**	**183**	**357**	**1,121**	**281**	**453**	**500**	**400**
Total Gross Capital Expenditures	**8,965**	**11,121**	**12,649**	**14,133**	**9,421**	**10,185**	**12,064**	**11,919**	**11,484**	**10,412**	**10,419**
Vehicle Disposals	0	0	0	(441)	(504)	(547)	(381)	(436)	(436)	(436)	(436)
Net Captial Additions after disposals	**8,965**	**11,121**	**12,649**	**13,692**	**8,918**	**9,638**	**11,683**	**11,483**	**11,048**	**9,976**	**9,983**

Average Net Capital Expenditures - 7 year (2011 - 2017)	**10,952**	**11 Year Average**	**10,832**
Average Fixed Asset additions COS rate Application 2015 net of average $850K capital contributions	**10,558**	**5 year average 2015-2019**	**10,554**

Appendix 1-6

NPEI 2016 Capital and Operating Budgets

2016
Capital
&
Operating
Budgets

Table of Contents

Niagara Peninsula Energy Inc.
Budget Report 2016

This report is prepared for the purpose of reviewing the significant factors affecting the 2015 and 2016 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.

2015 Highlights

100th Anniversary

In 2015, NPEI celebrated its 100th Anniversary. On July 7, 2015, the Niagara Parks Commission recognized NPEI with its Floral Clock Display, highlighting a Century of Power. NPEI hosted its first Lineman Rodeo on June 20th. The Rodeo was a huge success and will continue as an annual event. NPEI created a special 100th Anniversary calendar, wrapped a meter van with its new 100th anniversary logo, participated in the Niagara Falls Museum display and had a tree planting ceremony at its Corporate office in Niagara Falls. Members from the Board of Directors, senior management and employees participated in the Canada Day parade, the Big Bike Ride for Heart and Stroke Foundation and the CIBC Run for the Cure. In October, NPEI's linemen and outside workers wore pink hard hats in support of Breast Cancer research. NPEI participated in the Association of Municipalities of Ontario conference and will be hosting the Grid Smart City conference in November. On December 15th, the Niagara Falls Illumination Board will have a special 100th anniversary lighting of Niagara Falls in honour NPEI.

Conservation and Demand

In 2015, the Independent Electricity System Operator ("IESO") along with the former Ontario Power Authority ("OPA"), in response to a direction from the Ministry of Energy, implemented a new six year conservation framework. The Conservation First Framework is designed to reduce electricity consumption by 7 terawatt-hours (TWh) or seven billion kilowatt hours (kWh) by December 31, 2020. The Conservation First Framework will enable Local Distribution Companies (LDC's) to submit their Conservation and Demand Management (CDM) Plans and provide LDC's with long term, stable funding for CDM programs.

NPEI contracted ICF International to develop its CDM plan which was filed with the IESO on May 12, 2015. NPEI was assigned by the IESO a targeted persistent savings of 74.44 GWh by the end of 2020. NPEI's CDM budget funding of $19,056,865 will be received from the IESO over the next six years.

NPEI in conjunction with ICF International submitted a pilot program with the IESO called Energy Concierge Program for Hotels and Motels. The IESO approved NPEI's pilot program in October 2015 which will include 5 pilot participants from Niagara Falls. In collaboration with Enbridge Gas Distribution and the Ontario Restaurant Hotel and Motel Association ("ORHMA"), NPEI's pilot program will research leading-edge, energy efficient programs geared towards hotels and motels.

Customer Engagement

NPEI initiated several customer engagement activities in 2015. For every customer service call, a closing statement regarding customer satisfaction has been added. For every email received, a follow-up transactional customer satisfaction survey is emailed. In the event of a scheduled power outage, in addition to pre-notification of customers, NPEI completes follow-up direct commercial calls to review any impacts and to complete the process a customer satisfaction survey is emailed and results are recorded and analyzed for future scheduled power outages to minimize the impact to our customers.

NPEI will commence phase III of the overhead to underground primary conversion of plant and equipment in the Rolling Acres subdivision in the 4th quarter of 2015 and continue into 2016. NPEI held a town hall meeting with residents of the Rolling Acres subdivision in October. The meeting showed positive feedback and this process will be utilized on an on-going basis.

Customer Service held meetings with five of its large GS >50 kW customers in 2015. The purpose of the meetings was to educate these customers on the bill calculation, global adjustment and use of their own consumption and demand information within their forecasting processes. These meetings were influential in providing conservation opportunities for both NPEI and the customer.

Each month NPEI staff attends PUC (Public Utility Committee) meetings enabling NPEI to be aware of municipal and regional customer projects and needs. The initial stages of regional planning with Hydro One also began in 2015.

In the fourth quarter, NPEI facilitated a focus group of customers to review the benefits of direct deposit payments to its micro-fit customers. NPEI currently processes 383 micro-fit cheques each month. By enabling direct deposit NPEI would gain efficiencies in the processing of these cheques as well as improving efficiencies for its customers.

Customer Service and Billing

In 2015, NPEI completed the following customer interactive forms; connection agreements, PAP (Pre-authorized payments), owner memo, request for info, DRC (Debt Retirement Charge) exemption and self-declaration forms. NPEI continues to review its processes to gain efficiencies for example in 2015 NPEI performed a collections utilization review whereby, reminders and collection notices were automated. Collections processes are now a two-step process where a “soft” reminder notice is sent to customers who have good payment history but may have missed a payment and the second process follows the OEB’s (Ontario Energy Board) timeline for collections.

A billing utilization review was also completed resulting in load leveling of the billing schedule. Paperless services orders were introduced in billing in 2015 and month-end reporting was put onto a scheduler to improve day time production performance and efficiencies. By the end of 2015, all billing and customer service staff operating out of the office located in Smithville will transfer to the Niagara Falls office.

The DRC and the OCEB are being removed from the residential customer bills effective January 1, 2016. The Ministry of Energy announced in 2015 a new program to help low-income customers with their electricity bills. NPEI has been a member on the working group throughout 2015. The working group in consultation with the OEB and the IESO are designing the program. Changes to NPEI’s billing system will take place in December 2015 to ensure the company is compliant with the new program in January 2016.

Information Technology

The development of the virtual servers to be used for disaster recovery was completed in 2015. Testing of these servers will commence in 2016. The backup to/from Niagara Falls, Smithville and Sudbury on both the physical and virtual servers was completed during the year. This full backup system increased redundancy and allows for contingency planning. Call flow review was completed for NPEI’s telephone system. Corporate IT initiatives including the Engineering upgrades, control room and mobile device tools were supported by the IT department. Hand held devices for services orders and work tickets were upgraded to tablets.

Human Resources

NPEI’s negotiating committee successfully negotiated a four year contract with its IBEW union in 2015. The new contract is effective from April 1, 2015 to March 31, 2019. Wages increases in each of the years were as follows: 2015 – 2.1%, 2016 2.0% 2017 – 2.0% and 2018 – 2.0%.

The HR department in conjunction with a third party consultant was heavily involved in a Succession Planning initiative in 2015. Several management staff members are eligible for retirement in the upcoming five years. NPEI continues to invest in its employees where nine of its supervisors completed a leadership training course in 2015.

The HR department engaged a third party consultant to assist with the search and replacement of a Director of Engineering. A new Director of Engineering was hired at the beginning of October 2015.

As part of NPEI's mission statement and values, health and safety are one of NPEI's top priorities. NPEI achieved a record total of 324,460 hours without a lost time injury from April 3, 2013 to October 30, 2015. By the end of November all employees of the company will be certified with WSIB training.

Finance and Regulatory

As part of succession planning, all regulatory duties and responsibilities were restructured under the finance and regulatory department in 2015. NPEI filed its 2015 Cost of Service (COS) rate application in 2014. NPEI attended both a technical conference and a settlement conference with the intervenors and the OEB during 2015. "The Board issued a Rate Order on April 28, 2015 declaring NPEI's existing rates interim on May 1, 2015. As a result of this Decision, new rates for 2015 will be based on the Amended Settlement Proposal, utilizing a 13% WCA. The new 2015 rates will be implemented and effective as of June 1, 2015 and remain interim pending the results of the lead/lag study and NPEI obtaining the necessary, subsequent OEB approvals at the time of its next incentive rates application." NPEI in conjunction with a third party consultant prepared a Lead/Lag study. The result of this study illustrated a WCA of 13.22%. NPEI filed the lead/lag study with its IRM (Incentive Rate Mechanism) rate application in September 2015. Approval of the 2016 IRM rate application and lead/lag study are expected in the first quarter of 2016.

NPEI also completed an LRAM (Lost Revenue Adjustment Mechanism) rate application which covers the CDM programs from 2011 to 2014. The total LRAM application is $482,804.19. The LRAM will be a rate rider receivable from customers for a period of year effective May 1. 2016. This rate application is anticipated to be finalized and approved by the OEB in 2016.

NPEI underwent an OCEB (Ontario Clean Energy Benefit) audit and a PILS (Payment in lieu of taxes) audit in 2015. The OCEB audit resulted in no adjustments. The PILS audit is currently being reviewed by NPEI's previous auditors, Crawford, Smith & Swallow (CSS). With respect to NPEI's auditors, in March 2015, CSS informed NPEI that due to the costs involved with auditing an IFRS (International Financial Reporting Standards) client, CSS would no longer be able to perform NPEI's audit. NPEI adopted IFRS effective January 1, 2015. As a result, NPEI completed a request for proposal (RFP) for auditing services in 2015. KPMG was awarded the audit.

Strategic Planning

In 2015, NPEI engaged a third party consultant to update its strategic plan from 2008. This strategic plan is anticipated to be completed in 2016. As part of strategic planning, the organizational structure was reviewed. NPEI's mission, vision, values and strategic goals are being updated.

Basis of Presentation-Modified IFRS

The Canadian Accounting Standards Board ("AcSB") confirmed that publicly accountable enterprises will be required to adopt International Financial Reporting Standards ("IFRS") in place of Canadian general accepted accounting principles for reporting purposes for fiscal years beginning on or after January 1, 2015. NPEI will implement IFRS effective January 1, 2015 with comparative figures for 2014 restated under IFRS. As part of the RFP for auditing services, KPMG will perform a special audit of the conversion of the 2014 comparative figures from CGAAP to IFRS. The conversion and restatement of 2014 comparative figures along with the changes to the presentation of the financial statements under IFRS have not been completed at the time the budget was prepared. As a result the Financial Statements included in this budget report do not reflect IFRS presentation.

2015 Projected Balance Sheet

Total assets are projected at $179.8, which is up 1% or $2.2M from the 2014 total assets. This is mainly due to a net increase in fixed assets of $2.9M. Included in net fixed assets is $2.2M of capital contributions. Under IFRS presentation capital contributions will be reclassified to Deferred Revenue in the liabilities section of the balance sheet.

Cash is projected to be down by $1.7M from 2014. This is mainly due to the investment in fixed assets being financed internally.

Accounts receivable are projected to be up by 12% mainly due to the increase in the cost of power, network, connection, wholesale market and global adjustment charges.

Capital Additions 2015

Total gross capital expenditures are projected at $10.8M, offset by capital contributions of $2.2M for a net of $8.6M. The 2015 test year capital budget net of capital contributions approved in the 2015 COS rate application was $10.6M which is $2.0M higher than the projected 2015 expenditures. Capital projects are projected at $7.2M net of capital contributions of $2.0M.

Gross capital projects are less than the 2015 test year budget by $558K. This is mainly due to Phase III of Rolling Acres, Frederica Street, Willoughby Drive and Willoughby Drive extension being deferred to 2016 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 NWTC metering capital project had a change in scope, the meters were purchased in December 2014 and will be installed in 2016. Capital contributions also exceed the 2015 test year budget by $1.4M mainly due to an increase in subdivision activity in 2015. Also, NPEI budgeted $143K for the installation of MIST meters in 2015. Technology requirements for these replacement meters were still being investigated during 2015. NPEI estimates replacing 925 meters from 2016 to 2020. NPEI has included the 2015 purchases and installation of these meters in the 2016 capital budget.

Significant capital projects excluding capital contributions completed in 2015 are as follows:

Project	Adjusted to Rate App Gross Capital Investment	2015 Gross $ Projection	Projected vs Budget
Crawford St. Area Carry	282,324	475,000	192,676
Beck Road	144,237	170,000	25,763
Willodell Rebuild	310,710	320,000	9,290
Willoughby Drive	372,191	10,000	(362,191)
Willoughby Dr Extension	383,293	-	(383,293)
Switchgear	250,002	250,000	(2)
Rolling_Acres	1,033,077	575,000	(458,077)
NWTC Metering	289,605	-	(289,605)
Sectionalizing	73,000	60,000	(13,000)
Frederica	676,144	5,000	(671,144)
NPC	-	-	-
Reclosers	100,000	100,000	-
PCB TX Changeouts	495,104	235,000	(260,104)
Jordan Ph 2	449,324	450,000	676
King St. 27.6kV Ext at Martin	114,460	135,000	20,540
Lightning Mit.	30,000	5,000	(25,000)
Road Relocation	500,000	850,000	350,000
Pole Changeouts	431,729	600,000	168,271
Station 22 Loads S of Pew Carr	143,724	-	(143,724)
Station 22 Loads N of Pew	507,139	670,000	162,861
Kiosks	647,029	320,000	(327,029)
Sustainment	680,000	1,010,000	330,000
Subdiv Lots	275,000	325,000	50,000
Subdiv Conn	312,004	950,000	637,996
Lot Rebates	150,000	185,000	35,000
Demand	1,007,500	1,400,000	392,500
Metering	193,500	187,000	(6,500)
MIST meters	143,150	-	(143,150)
Totals	9,994,247	9,287,000	(707,247)

Significant demand projects included Hornblower, DSBN School, Smart Townes, Best Place on Clifton Hill, Vineland Research upgrade, King St. Bell joint use pole replacements, and LA Farina Bakery.

General plant and equipment are under budget by $419K and building additions are over budget by $387K. Building additions included the paving of the rear yard and a new ventilation system installed in the new stores area. The replacement of one of NPEI's large truck was deferred to 2016 and small vehicles slated to be replaced in 2016 were completed in 2015.

Computer hardware additions are projected at $240K. This included the replacement of servers, laptops and bluecoat web and antivirus network appliances which were at end of life.

Computer software additions are projected at $316K. Work management/Outage management and the GIS software were upgraded for legacy customizations. The implementation of automation platform and an update to the SQL server for the billing system were completed in 2015.

Vehicles > 3 tons included a 40' aerial squirt boom man-lift which replaced truck #45, a 2007 International aerial man-lift. Two large vehicles were disposed of in 2015, truck #11 was a 2004 bucket truck and truck #14 was a 2001 bucket truck. Vehicles < 3 tons included seven 4X4 crew cab trucks. Two of these trucks are additional complements to the fleet and five trucks were disposed and replaced.

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 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. The Wi-max communications projected capital expenditures was under budget in 2015 due to a lack of resources.

Liabilities and Share Holders Equity 2015

Current liabilities are projected to be $23.1M at the end of 2015. This is a decrease of $0.6M.

Accounts payable are projected to be $0.7M higher however the power bill is projected to be $0.5M lower. This is due to the reduction in NPEI's trading limit with the IESO in May 2015. The IESO updated prudential calculations for all LDC's in the province and NPEI's trading limit was lowered by approximately $2.0M due to the increase in the cost of power and global adjustment. As a result NPEI has experienced margin calls each month. A margin call results in power bill payments being made prior to the due date.

Regulatory Liabilities are projected to be $1.9M higher in 2015 than 2014. This increase is mainly due to the new variance account for Other Post-Employment Benefits (OPEB's). Under IFRS only the defined benefit obligation is included as a long-term liability on the Balance Sheet. The actuarial gains/losses as well as past service costs are included on the income statement in Other Comprehensive Income under IFRS. As part of the conversion from CGAAP to IFRS NPEI had an actuarial gain of $1.6M included in Employee Future Benefits on the Balance Sheet. During the COS rate application NPEI received approval from the OEB for the new OPEB variance account. This variance account will remain in regulatory liabilities until the next COS rate application in 2020. The RSVA (Retail Settlement Variance Account) is projected to be $2.8M higher than 2014. This is due to changes in the cost of power and global adjustment regulatory accounts. These increases in regulatory liabilities have been offset by the repayment of various regulatory liabilities currently included in NPEI's rate riders on its rate tariff. Under IFRS presentation, regulatory assets will be presented separately from regulatory liabilities on the balance.

Non-current liabilities are projected to decrease by $1.4M due to the actuarial gain being reallocated to the new OPEB variance account as noted above. Under IFRS presentation all of the customer deposits will be classified as current liabilities. Sick leave liability will be adjusted in 2015 as well as the comparative 2014 figure for an estimated sick leave liability for non-vested employees. This adjustment is not reflected in the 2015 projected balance sheet or the 2016 budget balance sheet.

Long-term liabilities are projected at $60.2M which is up by $1.0M over 2014. The former smart meter loan with Scotiabank had a term of 5 years and an amortization period of 10 years at 4.97%. The current portion balloon payment for this loan was due in September 2015 and was included in current liabilities in 2014. NPEI refinanced this loan over a term of 5 years at an interest rate of 2.67%.

In 2015, NPEI paid a total dividend of $1,200K to its shareholders proportionate to the shares held.

2015 Projected Income Statement

NPEI completed the Cost of Service Rate Application process in May of 2015 with rates effective June 1st, 2015. The Base Revenue Requirement amounted to $28,691,137 which is pending the result of the lead/lag study's Working Capital Allowance (WCA) calculation. The 2015 COS rate application included an update to the cost allocation model as well as a change in the revenue to cost ratio ranges set by the OEB. In 2011, the range for revenue to cost for the GS>50 rate class was from 80% to 160% and NPEI was at 148%. The updated revenue to cost ratio for this class is now 80% to 120%. As a result, the GS>50 rate class revenue requirement decreased and was offset by an increase to the Residential rate class. The change in the revenue to cost ratio also resulted in a shift to a higher variable rate versus the fixed rate for this rate class.

Total OM&A expenses are projected at $25.9M. Expenses are projected at $141k higher than the 2015 budget and $0.6K lower than 2014. As part of the regulatory liability related to the accounting changes under CGAAP a return on rate base associated with this account is to be included in the liability. NPEI's return on rate base is $740,792. This return was recorded 100% as carrying charges expense in 2015 and is included in the Interest expense line on the income statement. OM&A excluding interest and depreciation are $778K lower in 2015 versus 2014 due to smart meter expenses related to prior years were recorded in 2014.

OM&A expenses excluding interest and depreciation are projected at $16,386K which is $663K lower than the 2015 budget amount and $505K or 3.2% higher than 2014 excluding the adjustment for smart meters recorded in 2014.

Projected net income after taxes is estimated at $2.6M, which is $1.1M lower than budget and $290K higher than 2014.

Regulatory Net Income does not include the depreciation expense for the FMV bump of $1,089K. Projected 2015 regulatory net income before the extraordinary item related to the deferral and variance rate rider for PILS and income tax is $5,821K.

Gross profit percentage is projected to be 1.74 pts. below the 2015 original budget.

Gross profit before other revenue is projected to be $0.6M under budget and $2.1M under 2014. Gross profit for 2014 includes smart meter recoveries of $2.3M related to prior years.

Other revenues are projected $329K higher than budget. Interest charges on late hydro payments are projected to be over budget by $55K. NPEI received a performance incentive from the IESO in the amount of $278K related to NPEI exceeding is energy target savings for CDM from the 2011 to 2014 programs.

Cost of power is projected to increase over 2014 by $16.2M or 12%. This increase is mainly attributed to the increase in global adjustment expense.

2016 Budget Balance Sheet

Total Assets are budgeted at $180M which is $0.1K higher than projected total assets. Net capital additions total $5.4M. Cash has decreased by $5.5M which is due to the 2016 capital investment, principle repayment of existing loans in the amount of $1.7M and the repayment of regulatory liabilities in the amount of $2.8M.

NPEI included a dividend payment of $1.4M in the 2016 budget.

Gross capital additions related to the distribution system are budgeted at $12.2M, net of capital contributions of $0.8M for a total of $11.4M.

Please see below a table detailing the 2016 Major Capital projects. Three capital projects, Frederica to Dorchester to Drummond; Willoughby Drive-Main St to Cattell Drive; and Willoughby Drive Extension-Cattell to Weinbrenner Road are projects that were originally scheduled to be completed in 2015. Due to the increased demand for servicing commercial customers, sustainment and subdivision work in 2015 these three projects were deferred to 2016. The total capital amount deferred to 2016 is $1,421K. As a result the original 2016 budget was decreased by $486K, related to replacement of poles and OH line rebuilds and the Rolling Acres Phase 3 project.

APPENDIX B
List of Projects

Item	Project #	Project	Gross Capital Investment	Capital Contribution	Net Capital Investment
1	2016-0001	Dorchester-McLeod-Dunn	531,912	-	531,912
2	2016-0002	Oakwood Dr-Pole#111-25 to Pole # 98-7	611,940	-	611,940
3	2016-0003	600MCM U/G Install- Glenholme-Franklin	133,262	-	133,262
4	2016-0004	Willoughby Drive-Main St to Cattell Drive	369,271		369,271
5	2016-0005	Willoughby Dr Extend-Cattell to Weinbrenner	380,290		380,290
6	2016-0006	Pad-mounted Switchgear Replacements	250,002	-	250,002
7	2016-0008	OH to U/G conversion-Rolling Acres Phase 3	405,867	-	405,867
8	2016-0009	Clifton Hill Primary Upgrade	237,796	-	237,796
9	2016-0010	Additional Sectionalizing Switches - 8 units	73,000	-	73,000
10	2016-0011	Frederica to Dorchester to Drummond	671,753		671,753
11	2016-0012	Victoria Ave Fly Rd South Ext Ph I	298,862	-	298,862
12	2016-0013	1-Phase Hydraulic Reclosure Upgrades - 10 units	100,000	-	100,000
13	2016-0015	Jordan Road-Voltage Conversion Ph III	335,377	-	335,377
14	2016-0017	Downtown Core PILCDSTA De-commission	795,701	-	795,701
15	2016-0018	Dorchester - Mountain Road Riall Street	626,867	-	626,867
16	2016-0019	Lightning Mitigation Measures	30,000	-	30,000
17	2016-0021	NS&T Highway Double Cct. O/H Crossing Replace	272,236	-	272,236
18		Line Relocations due to Municipal Road Improvements	500,000	250,000	250,000
19	2016-1010/2010	Replacement of Poles Identified and O/H line rebuilds	535,930	-	535,930
20	2016-0020	Replace Kiosks with Transformers	841,137	-	841,137
21	2016-1007/2007	System Sustainment Allowance	680,000	-	680,000
22		Lot Servicing of existing lots	275,000	-	275,000
23		Connection and energizing of new subdivisions	312,004	200,000	112,004
24		Lot connection rebates	150,000	-	150,000
25	2016-1008/2008	Demand based system reinforecements for new commercial service connections	1,007,500	350,000	657,500
26		Metering - General	193,500	-	193,500
27		MIST Meters	287,360	-	287,360
			10,906,567	800,000	10,106,567
		Total Labour	3,793,840		
		Total Truck	1,065,360		
		Total Material	3,558,750		
		Total AP	2,488,617		
		Total before Contributions	10,906,567		
		SA - System Access	2,682,543	-	2,682,543
		SR- System Renewal	3,441,592	-	3,441,592
		SS- System Service	4,782,432	800,000	3,982,432
			10,906,567	800,000	10,106,567

Detailed descriptions of these capital projects can be found in the 2016 Capital projects section, Tab 5. See Appendix B.

Other Capital Additions

Building

In 2016, NPEI has included $87K for a concrete pad for garbage bins in the rear year at Niagara Falls and $27K for the initial phase of redesigning the control room.

General Equipment

Ergonomic office equipment mainly comprises the general and equipment budget. See Appendix C for details.

Hardware & Software

The Information Technology capital expenditures for 2016 continue to ensure that business goals are aligned to technological solutions. NPEI's network infrastructure will be optimized allowing for improved business uptime and resiliency.

The hardware and software requirements within each area allow for the following goals to be met:

- Effective and efficient business processes
- Support of risk and compliance management processes and methodology (enabling a methodology, not defining)
- Integrated, reliable, enterprise solutions
- Network integration and security
- Embedded business continuity practices, and continued update and testing of a Disaster Recovery Plan

Spending of hardware will be managed with greater emphasis on network infrastructure and new business requirements.

Hardware

The following outlines the proposed 2016 costs. Costs are related to the following projects/business need:

- Upgrade of PC's and monitors and laptops due to age and use
- Hardware server requirements for backup SQL server and new VM requirements

Software

Software required for business process improvement projects and new requirements, which promote efficiency and reliability including the following:

- Network security and backup solutions for disaster recovery

- Disaster recovery testing
- Work Management/Outage Management Intergraph solution including software and professional services for upgrade, installation and training.
- Spot sheet/work ticket replacement program

In review of the business requirements put forth and determination of what software is considered as part of the capital budget, key areas are reviewed. Customer engagement is of high importance.

NPEI remains customer focused. Through technology, customer service surveys, customer feedback on-line forums, NPEI is prepared to undertake activities that will allow us to understand customer's preferences and to address these preferences. Whether it is data access, support of distributed generation through streamlined processes, online application support or ease of access of customer consumption data and generation, information technology investments will allow NPEI to provide information and education to customers. Customers will be able to make decisions affecting their electricity costs with the access to real time data and behind the meter services and applications. NPEI itself will have opportunities for operational efficiencies through the use of data analytic tools and automated platforms.

See Appendices D and E for details related to the hardware and software budgets.

<u>Vehicles</u>

NPEI has included the replacement of one RBD (Radial Boom Derrick), one Material Handler large truck and backhoe with bobcat skid steer. Two small vehicles in the 2016 budget will also be replaced. See Appendix F for details.

<u>Tools and Equipment for vehicles</u>

Tools in the amount of $70K for the garage and fleet are detailed in Appendix G.

<u>Communications</u>

NPEI commenced the Wi-max pilot project in 2012 as noted above. The proposed 2016 Communications budget is for an expansion of this project for $150K. See Appendix H.

2016 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"). NPEI's rates were approved by the OEB on an interim basis pending the filing of a lead/lag study addressing the 13% WCA used in the rate application.

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

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 2016 Distribution Revenue is based on the 2016 IRM rate application that was submitted to the OEB in September 2015.

As part of the Renewed Regulatory Framework in Electricity, the OEB indicated that the revenue decoupling consultation would move forward.

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. Revenue decoupling will take place over the next 4 years for NPEI's residential customers. This entails a shift from the distribution volumetric charge to the fixed monthly service charge for residential ratepayers. The 2016 budget incorporates this shift in service revenue.

Cost of Power

Cost of power is budgeted at $153.5M in 2016 which is $0.5M higher than the 2015 projected and $9.4M higher than the cost of power calculated in the rate application.

Other Revenue

Other revenue is budgeted at $1.4M which is $323K lower than the projected 2015 due to the performance incentive of $278K being received as a one-time payment in 2015. Total other revenue budgeted in 2016 is consistent with the rate application filing.

OM&A Expenses

NPEI developed its' operational, maintenance and general administration ("OM&A") distribution expenses based on the four outcomes noted above and the 2015 test year OM&A distribution expenses approved on an interim basis in the CoS rate application. Total OM&A expenses of $16,424K excluding interest expense and depreciation are reflected in the 2016 budget. Adjustments were made in the 2016 OM&A expenses reflecting activity which occurred in 2015.

Interest Expense

Interest expense is budgeted at $2.5M in 2016. No new financing is anticipated at the time this budget has been prepared. Interest expense is lower than the projected 2015 amount of $3.3M due to the one-time entry in 2015 related to the regulatory liability account for changes in accounting for CGAAP.

Depreciation Expense

Depreciation expense included in the rate application totals $5,034K. NPEI prepared its 2016 Budgeted depreciation based on the CoS rate application which was approved on an interim basis by the OEB. Depreciation is lower in 2016 versus 2014 by $257K due to an entry related to prior year smart meters costs make in 2014 in the amount of $273K.

Wages and Benefits

NPEI's current collective agreement expires March 31, 2019. The 2016 budgeted wages and benefits include a 2% increase and there were no changes made in the budget to the current payroll benefit burden.

There are three retirements of management personnel in 2016, where all three positions will be back-filled between 2015 and 2016. The Controller is budgeted to return from a maternity leave in 2016. The recruitment for the system analyst position was completed in November 2015. The successful candidate is anticipated to commence in January 2016. An additional Engineering Technician has been included in the 2016 budget.

MIST meters

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 has included $43K in 2016 related to MIST meter reading costs.

Net Income After Taxes

Net income after taxes is budgeted at $3.4M which is $0.8M higher than the projected 2015 net income after 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.

In conclusion, NPEI has continued to maintain the level of distribution expenses in 2016 as compared to the projected 2015. NPEI’s continued investments in its’ employees, distribution infrastructure, capital fleet and technology will result in the company’ 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 recommends approval as follows:

1. The 2016 Capital budget of $11,375,000 be approved, this is comprised of net distribution additions of $10,107,000, information technology, fleet and communication expenditures of $1,181,000, and building expenditures of $87,000.

2. The 2016 total operating expenditures in the amount of $25,442,000 including depreciation and depreciation related to the fair market value bump are approved.

Niagara Peninsula Energy
Financial Ratios
2013 to 2016

	2016 Budget	2015 Projected	2015 Budget	2014 Actual	2013 Actual
EBITDA %					
Net Income	3,385,862	2,637,066	3,783,102	2,347,072	1,458,179
add back Depreciation FMV bump	1,084,545	1,088,860	1,087,000	1,099,638	1,132,277
add back PILS repayment			-	632,525	1,554,749
Regulatory Net Income	4,470,407	3,725,926	4,870,102	4,079,235	4,145,205
Interest	2,532,433	3,340,568	2,719,027	2,592,428	2,445,708
Pils	1,611,779	2,094,611	1,374,000	449,350	596,930
Depreciation	5,391,974	5,117,708	4,937,000	5,649,681	5,321,041
EBITDA	14,006,593	14,278,812	13,900,129	12,770,694	12,508,884
Total Gross Profit	30,439,804	30,664,496	30,948,000	32,415,990	28,498,194
EBITDA %	46.01%	46.56%	44.91%	39.40%	43.89%
Return on assets					
Regulatory Net Income	4,470,407	3,725,926	4,870,102	4,079,235	4,145,205
Total Assets	181,311,959	181,726,388	176,905,000	172,442,124	177381000
Return on assets	2.47%	2.05%	2.75%	2.37%	2.34%
Financial Statement Return on Equity					
Regulatory Net Income	4,470,407	3,725,926	4,870,102	4,079,235	4,145,205
Total Equity	76,328,099	74,356,236	73,314,170	70,743,037	68,496,330
F/S Return on Equity	5.86%	5.01%	6.64%	5.77%	6.05%
Liquidity ratio					
Current Assets	36,541,728	41,843,108	36,899,000	44,147,757	43,517,951
Current Liabilities	25,523,956	23,115,157	27,532,000	23,677,522	23,294,043
	1.43	1.81	1.34	1.86	1.87
Debt to Total Assets					
Total Debt	60,084,161	61,703,157	59,329,000	62,844,735	54714363
Total Assets	181,311,959	181,726,388	176,905,000	172,442,124	177,381,000
Ratio Debt/Total Assets	0.33	0.34	0.34	0.36	0.31
Debt to Equity Ratio					
Total Debt	60,084,161	61,703,157	59,329,000	62,844,735	54,714,363
Total Equity	76,328,099	74,356,236	73,314,170	70,743,037	68,496,330
Debt/Equity Ratio	0.79	0.83	0.81	0.89	0.80
Calculation of ROE on a Deemed Basis	6.39%	6.52%	9.00%	4.89%	6.71%

Niagara Peninsula Energy
Projected Balance Sheet
As at December 31, 2015
(000's)

	Projected 2015	Actual 2014	$ Variance	% Variance
ASSETS				
Current Assets				
Cash	8,912	10,592	(1,681)	-16%
Accounts Receivable	13,892	12,411	1,481	12%
Unbilled Revenue	16,734	16,221	513	3%
Due from Affiliated Companies				
Niagara Falls Hydro Holding Corporation	5	6	(1)	-23%
Peninsula West Services	(19)	(24)	4	-18%
Payments in lieu of corporate taxes refundable	0	1,062	(1,062)	-100%
Inventories	1,431	1,481	(50)	-3%
Prepaid Expenses	889	768	121	16%
	41,843	**42,517**	**(674)**	**-2%**
Fixed Assets				
Land and land rights	2,963	2,963	0	0%
Buildings	17,436	16,962	474	3%
Distribution Stations	9,383	9,382	1	0%
Transformer Station	6,576	6,576	(0)	0%
Distribution lines				
Overhead	101,025	96,247	4,778	5%
Underground	85,074	83,700	1,375	2%
Distribution transformers	40,654	39,793	862	2%
Distribution meters	10,148	9,964	184	2%
Trucks and Equipment	21,953	21,067	886	4%
	295,214	286,654	8,560	3%
Less: Accumulated Depreciation	(158,441)	(152,743)	(5,698)	4%
	136,773	**133,911**	**2,862**	**2%**
Future payments in lieu of taxes	**1,204**	**1,204**	0	0%
TOTAL ASSETS	**179,820**	**177,632**	**2,188**	**1%**

Niagara Peninsula Energy
Projected Balance Sheet
As at December 31, 2015
(000's)

	Projected 2015	Actual 2014	$ Variance	% Variance
LIABILITIES				
Current Liabilities				
Accounts Payable	8,060	7,353	706	10%
Power bill payable	11,149	11,652	(503)	-4%
Taxes Payable	757	0	757	#DIV/0!
Deferred Capital Contributions	9	64	(56)	-87%
Deferred OPA revenues	979	444	535	121%
Deferred Standard Offer Revenue	6	13	(7)	-55%
Current Portion of other liabilities	736	729	8	1%
Current Portion of long term debt	1,420	3,515	(2,095)	-60%
	23,115	**23,770**	**(655)**	**-3%**
Regulatory Liabilities				
Retail Cost Variances	(149)	(390)	241	-62%
Retail Settlement Variances	2,647	(103)	2,751	-2659%
Low Voltage Variances	(618)	(174)	(444)	255%
SmartGrid OMA Deferral (GEA)	0	(19)	19	-100%
Stranded Meters	(900)	(1,284)	383	-30%
Other Regulatory Assets	1,540	(28)	1,568	-5645%
Mist Meter Variance	44	0	44	#DIV/0!
Smart Metering Entity Variance	24	(27)	51	-186%
Deferral Change in Accounting Policy Depreciation	4,708	6,170	(1,462)	-24%
Deferral & Variance Recovery 2012 application	0	39	(39)	-100%
Deferral & Variance Recovery 2014 application	172	1,185	(1,013)	-86%
Deferral & Variance Recovery 2015 COS application	(239)	0	(239)	#DIV/0!
	7,228	**5,369**	**1,859**	**35%**
Non-Current Liabilities				
Employee Sick Leave Liability	39	50	(11)	-21%
Employee Future Benefits	2,504	3,907	(1,403)	-36%
Customer Deposits	773	766	8	1%
	3,317	**4,723**	**(1,406)**	**-30%**
Long Term 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	34,678	33,725	953	3%
	60,283	**59,330**	**953**	**2%**
Shares				
Share Capital	31,246	31,246	0	0%
Contributed Surplus	25,459	25,459	(0)	0%
Retained Earnings	29,173	27,735	1,437	5%
	85,878	**84,441**	**1,437**	**2%**
TOTAL LIABILITIES & EQUITY	**179,820**	**177,632**	**2,187**	**1%**

Niagara Peninsula Energy
Projected Statement of Operations vs Budget
For the year ending December 31, 2015
(000's)

	Projected 2015	Budget 2015	Projected vs Budget $ Variance	Projected vs Budget % Variance	Actual 2014	Projected 2015 vs Actual 2014 $ Variance	Projected 2015 vs Actual 2014 % Variance
SERVICE REVENUE							
Standard Supply Service NF	128,115	113,866	14,250	13%	113,775	14,341	13%
Wholesale, Network & Connection Charges	24,900	23,078	1,823	8%	23,072	1,829	8%
Service Charge	13,783	14,996	(1,213)	-8%	15,828	(2,046)	-13%
Distribution Volumetric Charge	14,924	14,323	601	4%	15,066	(142)	-1%
Standard Supply Service Admin Charge	146	141	5	4%	145	1	1%
Retailer Revenue	40	45	(6)	-13%	43	(3)	-7%
	181,908	166,448	15,459	9%	167,928	13,979	8%
Cost of Power							
Power Purchased	153,016	136,943	(16,073)	-12%	136,846	(16,169)	-12%
Gross Profit Before Other Revenue	28,892	29,505	(613)	-2%	31,082	(2,190)	-7%
Other Revenue	1,773	1,443	329	23%	1,967	(194)	-10%
Less: Regulatory Debit	0	0	0	0%	3,115	(3,115)	-100%
Gross Profit	30,664	30,948	(284)	-0.92%	29,933	731	2%
Expenses							
Operation and maintenance							
Distribution	6,231	6,747	516	8%	6,594	363	6%
Utilization	234	176	(58)	-33%	206	(28)	-14%
Administration & general	4,760	4,516	(244)	-5%	4,425	(334)	-8%
Billing & Collecting	5,161	5,610	449	8%	5,938	777	13%
Interest Expense	3,341	2,719	(622)	-23%	2,592	(748)	-29%
Depreciation	5,118	4,937	(181)	-4%	5,650	532	9%
Depreciation on FMV adjustment of fixed assets	1,089	1,087	(2)	100%	1,100	11	1%
TOTAL EXPENSES	25,933	25,792	(141)	-1%	26,504	571	2%
Net Income before Extraordinary Item	4,732	5,157	(425)	-8%	3,429	1,303	38%
Extraordinary Item							
Deferral & Variance (Refund)/Recovery PILS	0	0	0	100%	633	633	100%
Net Income After Extraordinary Item	4,732	5,157	(425)	-8%	2,796	1,935	69%
Payments in Lieu of Income Taxes							
Income Tax expenses - current	2,095	1,374	(721)	-52%	449	(1,645)	-366%
Total payments in lieu of income taxes	2,095	1,374	(721)	-52%	449	(1,645)	-366%
Net Income/(Loss) After Taxes	2,637	3,783	(1,146)	-30%	2,347	290	12%

Statistics

	Projected 2015	Budget 2015	Projected vs Budget	Actual 2014	Projected 2015 vs Actual 2014
Cost of Power %	84.12%	82.27%	(1.84) pts	81.49%	(2.63) pts
Gross Profit % After Other Revenue	16.86%	18.59%	(1.74) pts	17.82%	(0.97) pts
Total Expenses as % of Total Revenue	14.26%	15.50%	1.24 pts	15.78%	1.53 pts
Net Income After Tax as % of Total Revenue	1.45%	2.27%	(0.82) pts	1.40%	0.05 pts
Income Tax % of Net Income	35.99%	22.00%	13.99 pts	9.92%	26.06 pts
Other Revenue	0.97%	0.87%	0.11 pts	1.17%	(0.20) pts
Distribution	3.43%	4.05%	0.63 pts	3.93%	0.50 pts
Utilization	0.13%	0.11%	(0.02) pts	0.12%	(0.01) pts
Administration & general	2.62%	2.71%	0.10 pts	2.64%	0.02 pts
Billing & Collecting	2.84%	3.37%	0.53 pts	3.54%	0.70 pts
Depreciation	2.81%	2.97%	0.15 pts	3.36%	0.55 pts

Niagara Peninsula Energy Inc.
Statement of Retained Earnings
for the year ending December 31, 2015
(000's)

	Projected 2015	Actual 2014
Retained Earnings, Beginning of Year	27,735	26,588
Net Income	2,637	2,347
Dividends on common shares	(1,200)	(1,200)
Retained Earnings, End of Period	29,173	27,735

Niagara Peninsula Energy Inc.
Statement of Cash Flows
For the year ending December 31, 2015

	Projected 2015 $	Actual 2014 $
Cash Provided By (Used In):		
Operations		
Net Income for the year	2,637	2,347
Items not involving cash		
Depreciation	5,118	5,650
Depreciation expense on fair market value adjustment of fixed assets	1,089	1,100
Future payments in-lieu of taxes	(0)	(124)
Employee future benefits	(1,403)	21
Regulatory Debit	0	3,115
	7,440	12,109
Changes in non-cash working capital components	(1,658)	3,245
	5,782	15,355
Investments		
Due to affiliated companies	3	(6,893)
Additions to property and equipment-net	(9,074)	(14,346)
Regulatory costs	1,859	(1,910)
	(7,212)	(23,150)
Financing		
Long-Term Deposits	8	38
Employees' accumulated vested sick leave	(11)	(63)
Long Term Bank Loan	953	8,130
Dividend on Common Shares	(1,200)	(1,200)
	(250)	6,906
Increase (Decrease) in Cash Position	(1,681)	(889)
Cash Position, Beginning of Year	10,592	11,481
Cash Position, End of Year	8,912	10,592

Niagara Peninsula Energy
Projected Capital Budget
For the year ending December 31, 2015
(000's)

	2015 Test Year			Original		Projected
	Projected 2015	Approved in Rate App	Projected vs Test Year Variance	Budget 2015	Actual 2014	2015 vs 2014 Variance
Land and Land Rights	0	0	0	0	0	0
Buildings & Fixtures	474	87	(387)	220	1,613	1,139
Sub Total	474	87	(387)	220	1,613	1,139
Distribution Station	1	0	(1)	0	514	513
Transformer Station	0	0	0	0	16	16
Overhead Distribution	4,933	4,505	(428)	4,533	4,362	(571)
Underground Distribution	2,925	3,514	588	3,842	3,470	545
Distribution Transformers	1,323	1,547	224	1,547	1,135	(188)
Meters	255	285	29	428	396	140
Smart Meters	0	143	143	0	146	146
Capital Contributions	(2,238)	(828)	1,410	(828)	(1,388)	850
Sub Total	7,200	9,166	1,966	9,523	8,651	1,451
Office Furniture & Equipment	26	33	7	69	177	151
Computer Equipment, Hardware	240	240	(0)	235	279	39
Computer Software	316	369	53	488	538	222
Vehicles < 3 tonnes	236	114	(122)	285	0	(236)
Vehicles > 3 tonnes	254	514	260	343	631	377
Vehicles transportation other	0	71	71	225	21	21
Vehicle Disposals	(377)	(314)	63	0	(441)	(64)
Stores Equipment	54	0	(54)	0	32	(22)
Tools, Shop & Garage Equipment	68	61	(8)	68	60	(8)
Measurement & Testing Equipment	0	1	1	1	0	0
Communication equipment	68	215	147	215	228	160
Miscellaneous equipment	0	1	1	1	0	0
Sub Total	886	1,305	419	1,931	1,526	640
Total Capital before smart meter additions from prior years	**8,560**	**10,558**	**1,998**	**11,673**	**11,790**	**3,230**
Smart Meters Prior Years	0	0	0	0	1,903	1,903
Total capital expenditures	**8,560**	**10,558**	**1,998**	**11,673**	**13,693**	**5,133**

Niagara Peninsula Energy
Budget Balance Sheet
As at December 31, 2016
(000's)

	Budget 2016	Projected 2015	$ Variance	% Variance	Actual 2014	$ Variance	% Variance
ASSETS							
Current Assets							
Cash	3,357	8,912	(5,554)	-62.3%	10,592	(1,681)	-16%
Accounts Receivable	14,030	13,892	139	1.0%	12,411	1,481	12%
Unbilled Revenue	16,901	16,734	167	1.0%	16,221	513	3%
Due from Affiliated Companies							
Niagara Falls Hydro Holding Corporation	5	5	0	0%	6	(1)	0%
Peninsula West Services	(19)	(19)	0	0%	(24)	4	-18%
Payments in lieu of corporate taxes refundable	0	0	0	0%	1,062	(1,062)	-100%
Inventories	1,360	1,431	(72)	-5%	1,481	(50)	-3%
Prepaid Expenses	907	889	18	2%	768	121	16%
	36,542	**41,843**	**(5,301)**	**-13%**	**42,517**	**(674)**	**-2%**
Fixed Assets							
Land and land rights	2,963	2,963	0	0%	2,963	0	0%
Buildings	17,523	17,436	87	0%	16,962	474	3%
Distribution Stations	9,383	9,383	0	0%	9,382	0	0%
Transformer Station	6,576	6,576	0	0%	6,576	0	0%
Distribution lines							
Overhead	105,658	101,025	4,633	5%	96,247	4,778	5%
Underground	88,916	85,074	3,842	5%	83,700	1,375	2%
Distribution transformers	41,714	40,654	1,060	3%	39,793	862	2%
Distribution meters	10,721	10,148	572	6%	9,964	184	2%
Trucks and Equipment	23,134	21,953	1,181	5%	21,067	886	4%
	306,588	295,214	11,375	4%	286,654	8,560	3%
Less: Accumulated Depreciation	(164,419)	(158,441)	(5,979)	4%	(152,743)	(5,698)	4%
	142,169	**136,773**	**5,396**	**4%**	**133,911**	**2,862**	**2%**
Future payments in lieu of taxes	**1,204**	**1,204**	**0**	**0%**	**1,204**	**0**	**0%**
TOTAL ASSETS	**179,915**	**179,820**	**95**	**0%**	**177,632**	**2,188**	**1%**

Niagara Peninsula Energy
Budget Balance Sheet
As at December 31, 2016
(000's)

	Budget 2016	Projected 2015	$ Variance	% Variance	Actual 2014	$ Variance	% Variance
LIABILITIES							
Current Liabilities							
Accounts Payable	9,505	8,060	1,446	18%	7,353	706	10%
Power Bill Payable	11,449	11,149	300	3%	11,652	(503)	-4%
Taxes Payable	757	757	0	0%	0	757	100%
Deferred Capital Contributions	0	9	(9)	-100%	64	(56)	-87%
Deferred Standard Offer Revenue	6	6	0	0%	444	(438)	-99%
Deferred OPA revenues	1,590	979	611	62%	13	966	7635%
Current Portion of other liabilities	751	736	15	2%	729	8	1%
Current Portion of long term debt	1,466	1,420	46	3%	3,515	(2,095)	-60%
	25,524	**23,115**	**2,409**	**10%**	**23,770**	**(655)**	**-3%**
Regulatory Liabilities							
Retail Cost Variances	(261)	(149)	(112)	75%	(390)	241	-62%
Retail Settlement Variances	2,912	2,647	265	10%	(103)	2,751	-2659%
Low Voltage Variances	(858)	(618)	(240)	39%	(174)	(444)	255%
SmartGrid OMA Deferral (GEA)	0	0	0	0%	(19)	19	-100%
Stranded Meters	(264)	(900)	636	-71%	(1,284)	383	-30%
Other Regulatory Assets	1,540	1,540	0	0%	(28)	1,568	-5645%
Mist Meter Variance	88	44	44	100%	0	44	100%
Smart Metering Entity Variance	38	24	14	59%	(27)	51	-186%
Deferral Change in Accounting Policy Depreciation	988	4,708	(3,720)	-79%	6,170	(1,462)	-24%
Deferral & Variance Recovery 2012 application	0	0	0	0%	39	(39)	-100%
Deferral & Variance Recovery 2014 application	172	172	0	0%	1,185	(1,013)	-86%
Deferral & Variance Recovery 2015 application	(14)	(239)	225	-94%	0	(239)	100%
	4,340	**7,228**	**(2,888)**	**-40%**	**5,369**	**1,859**	**35%**
Non-Current Liabilities							
Employee Sick Leave Liability	177	39	138	350%	50	(11)	-21%
Employee Future Benefits	2,619	2,504	115	5%	3,907	(1,403)	-36%
Customer Deposits	773	773	0	0%	766	8	1%
	3,570	**3,317**	**253**	**8%**	**4,723**	**(1,406)**	**-30%**
Long Term Liabilities							
Long Term Note Payable to City of Niagara Falls	22,000	22,000	0	0%	22,000	0	0%
Long Term Note Payable NF Hydro Holding	3,605	3,605	0	0%	3,605	0	0%
Long Term Bank Loan	33,013	34,678	(1,665)	-5%	33,725	953	3%
	58,618	**60,283**	**(1,665)**	**-3%**	**59,330**	**953**	**2%**
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	31,158	29,173	1,986	7%	27,735	1,437	5%
	87,864	**85,878**	**1,986**	**2%**	**84,441**	**1,437**	**2%**
TOTAL LIABILITIES & EQUITY	**179,915**	**179,820**	**95**	**0%**	**177,632**	**2,188**	**1%**

Niagara Peninsula Energy Inc.
Budgeted Statements of Operations
For the year ending December 31, 2016
(000's)

	Budget 2016	Projected 2015	2016 vs 2015 $ Variance	2016 vs 2015 % Variance	Actual 2014	2015 vs 2014 $ Variance	2015 vs 2014 % Variance	Rate Application Test Year
SERVICE REVENUE								
Standard Supply Service NF	128,621	128,115	505	0.39%	113,775	14,341	12.60%	120,621
Wholesale, Network & Connection Charges	24,929	24,900	29	0.12%	23,072	1,829	7.93%	23,529
Service Charge	14,897	13,783	1,114	8.09%	15,828	(2,046)	-12.92%	14,897
Distribution Volumetric Charge	13,901	14,924	(1,022)	-6.85%	15,066	(142)	-0.95%	13,901
Standard Supply Service Admin Charge	147	146	1	0.44%	145	1	0.90%	147
Retailer Revenue	45	40	6	14.96%	43	(3)	-7.21%	45
	182,540	181,908	632	0.35%	167,928	13,979	8.32%	173,140
Cost of Power								
Power Purchased	153,550	153,016	(534)	-0.35%	136,846	(16,169)	-11.82%	144,150
Gross Profit Before Other Revenue	28,991	28,892	99	0.34%	31,082	(2,190)	-7.05%	28,991
Other Revenue	1,449	1,773	(323)	-18.24%	1,967	(194)	-9.87%	1,449
Less: Regulatory Debit	0	0	0	0.00%	3,115	(3,115)	-100.00%	0
Gross Profit	30,440	30,664	(225)	-0.73%	29,933	731	2.44%	30,440
Expenses								
Operation and maintenance								
Distribution	6,167	6,231	64	1.03%	6,594	363	5.50%	6,521
Utilization	234	234	(0)	-0.13%	206	(28)	-13.80%	169
Administration & general	4,770	4,760	(10)	-0.21%	4,425	(334)	-7.56%	4,486
Billing & Collecting	5,263	5,161	(101)	-1.97%	5,938	777	13.08%	5,249
Interest Expense	2,532	3,341	808	24.19%	2,592	(748)	-28.86%	3,296
Depreciation Expense	5,392	5,118	(274)	-5.36%	5,650	532	9.42%	5,034
Depreciation on FMV adjustment of fixed assets	1,085	1,089	4	0.40%	1,100	11	0.98%	0
TOTAL EXPENSES	25,442	25,933	491	1.89%	26,504	571	2.16%	24,755
Net Income before Extraordinary Item	4,998	4,732	266	5.62%	3,429	1,303	37.99%	5,685
Extraordinary Item								
Deferral & Variance Refund/Recovery PILS	0	0	0	0.00%	633	633	100.00%	0
Net Income After Extraordinary Item	4,998	4,732	266	5.62%	2,796	1,935	69.20%	5,685
Payments in Lieu of Income Taxes								
Income Tax expenses - current	1,612	2,095	(483)	-23%	449	(1,162)	-259%	168
Total payments in lieu of income taxes	1,612	2,095	(483)	-23%	449	(1,162)	-259%	168
Net Income/(Loss) After Taxes	3,386	2,637	749	28.40%	2,347	3,098	131.98%	5,516

Statistics	Budget 2016	Projected 2015	2016 vs 2015	Actual 2014	2015 vs 2014	Rate Application Test Year
Cost of Power %	84.12%	84.12%	(0.00) pts	81.49%	(2.63) pts	83.26%
Gross Profit % After Other Revenue	16.68%	16.86%	(0.18) pts	17.82%	(0.97) pts	17.58%
Total Expenses as % of Total Revenue	13.94%	14.26%	0.32 pts	15.78%	1.53 pts	14.54%
Net Income After Tax as % of Total Revenue	1.85%	1.45%	0.41 pts	1.40%	0.46 pts	1.72%
Income Tax % of Net Income	26.50%	35.99%	(9.49) pts	9.92%	16.58 pts	43.41%
Other Revenue	0.79%	0.97%	(0.18) pts	1.17%	(0.38) pts	0.84%
Distribution	3.38%	3.43%	0.05 pts	3.93%	0.50 pts	3.56%
Utilization	0.13%	0.13%	0.00 pts	0.12%	(0.01) pts	0.14%
Administration & general	2.61%	2.62%	0.00 pts	2.64%	0.02 pts	2.75%
Billing & Collecting	2.88%	2.84%	(0.05) pts	3.54%	0.70 pts	3.04%
Depreciation	2.95%	2.81%	(0.14) pts	3.36%	0.55 pts	2.85%

Niagara Peninsula Energy Inc.
Statement of Retained Earnings
for the year ending December 31, 2016
(000's)

	Budget 2016	Projected 2015	Actual 2014
Retained Earnings, Beginning of Year	29,173	27,735	26,588
Net Income	3,386	2,637	2,347
Dividends on common shares	(1,400)	(1,200)	(1,200)
Retained Earnings, End of Period	31,158	29,173	27,735

Niagara Peninsula Energy Inc.
Statement of Cash Flows
For the year ending December 31, 2016

	Budget 2016 $	Projected 2015 $
Cash Provided By (Used In):		
Operations		
Net Income for the year	3,386	2,637
Items not involving cash		
Depreciation	5,392	5,118
Depreciation expense on fair market value adjustment of fixed assets	1,085	1,089
Employee future benefits	115	(1,403)
	9,978	7,440
Changes in non-cash working capital components	2,155	(1,658)
	12,133	5,782
Investments		
Due to affiliated companies	0	3
Additions to property and equipment-net	(11,873)	(9,074)
Regulatory costs	(2,888)	1,859
	(14,761)	(7,212)
Financing		
Long-Term Deposits	0	8
Employees' accumulated vested sick leave	138	(11)
Long Term Bank Loan	(1,665)	953
Dividend on Common Shares	(1,400)	(1,200)
	(2,927)	(250)
Increase (Decrease) in Cash Position	(5,555)	(1,680.54)
Cash Position, Beginning of Year	8,912	10,592
Cash Position, End of Year	3,357	8,912

Niagara Peninsula Energy Inc.
Capital Budget 2016
For the year ending December 31, 2016
(000's)

	Appendix	Proposed Budget 2016	Projected 2015	Proposed Budget 2016 vs Projected 2015 Variance	Actual 2014	Test Year Approved in Rate App
Land and Land Rights	A	0	0	0	0	0
Buildings & Fixtures	A	87	474	(387)	1,613	87
Sub Total		87	474	(387)	1,613	87
Distribution Station	B	0	1	(1)	514	0
Transformer Station	B	0	0	0	16	0
Overhead Distribution	B	4,633	4,933	(301)	4,362	4,505
Underground Distribution	B	4,292	2,925	1,366	3,470	3,514
Distribution Transformers	B	1,410	1,323	87	1,135	1,547
Meters	B	285	255	30	396	285
Smart Meters	B	287	0	287	146	143
Capital Contributions	B	(800)	(2,238)	1,438	(1,388)	(828)
Sub Total		10,107	7,200	2,906	8,651	9,166
Office Furniture & Equipment	C	20	26	(6)	177	33
Computer Equipment, Hardware	D	243	240	3	279	240
Computer Software	E	357	316	41	538	369
Vehicles < 3 tonnes	F	90	236	(146)	0	114
Vehicles > 3 tonnes	F	750	254	496	631	514
Vehicles Transportation Other	F	0	0	0	21	71
Vehicle Disposals		(498)	(377)	(122)	(441)	(314)
Stores Equipment		0	54	(54)	32	0
Tools, Shop & Garage Equipment	G	70	68	2	60	61
Measurement & Testing Equipment		0	0	0	0	1
Communication equipment	H	150	68	82	228	215
Miscellaneous equipment		0	0	0	0	1
Sub Total		1,181	886	296	1,526	1,305
Total Capital before smart meter additions from prior		**11,375**	**8,560**	**2,815**	**11,790**	**10,558**
Smart meter purchases from prior years		0	0	0	1,903	0
		11,375	**8,560**	**2,815**	**13,693**	**10,558**

APPENDIX A

Building 2016

	2016 Budget
Building	
Control Room Planning	27,000
Concrete Pad for Garbage Bins	60,000
Total	**87,000**

APPENDIX B
List of Projects

Item	Project #	Project	Gross Capital Investment	Capital Contribution	Net Capital Investment
1	2016-0001	Dorchester-McLeod-Dunn	531,912	-	531,912
2	2016-0002	Oakwood Dr-Pole#111-25 to Pole # 98-7	611,940	-	611,940
3	2016-0003	600MCM U/G Install- Glenholme-Franklin	133,262	-	133,262
4	2016-0004	Willoughby Drive-Main St to Cattell Drive	369,271		369,271
5	2016-0005	Willoughby Dr Extend-Cattell to Weinbrenner	380,290		380,290
6	2016-0006	Pad-mounted Switchgear Replacements	250,002	-	250,002
7	2016-0008	OH to U/G conversion-Rolling Acres Phase 3	405,867	-	405,867
8	2016-0009	Clifton Hill Primary Upgrade	237,796	-	237,796
9	2016-0010	Additional Sectionalizing Switches - 8 units	73,000	-	73,000
10	2016-0011	Frederica to Dorchester to Drummond	671,753		671,753
11	2016-0012	Victoria Ave Fly Rd South Ext Ph I	298,862	-	298,862
12	2016-0013	1-Phase Hydraulic Reclosure Upgrades - 10 units	100,000	-	100,000
13	2016-0015	Jordan Road-Voltage Conversion Ph III	335,377	-	335,377
14	2016-0017	Downtown Core PILCDSTA De-commission	795,701	-	795,701
15	2016-0018	Dorchester - Mountain Road Riall Street	626,867	-	626,867
16	2016-0019	Lightning Mitigation Measures	30,000	-	30,000
17	2016-0021	NS&T Highway Double Cct. O/H Crossing Replace	272,236	-	272,236
18		Line Relocations due to Municipal Road Improvements	500,000	250,000	250,000
19	2016-1010/2010	Replacement of Poles Identified and O/H line rebuilds	535,930	-	535,930
20	2016-0020	Replace Kiosks with Transformers	841,137	-	841,137
21	2016-1007/2007	System Sustainment Allowance	680,000	-	680,000
22		Lot Servicing of existing lots	275,000	-	275,000
23		Connection and energizing of new subdivisions	312,004	200,000	112,004
24		Lot connection rebates	150,000	-	150,000
25	2016-1008/2008	Demand based system reinforecements for new commercial service connections	1,007,500	350,000	657,500
26		Metering - General	193,500	-	193,500
27		MIST Meters	287,360	-	287,360
			10,906,567	800,000	10,106,567

Total Labour	3,793,840		
Total Truck	1,065,360		
Total Material	3,558,750		
Total AP	2,488,617		
Total before Contributions	10,906,567		
SA - System Access	2,682,543	-	2,682,543
SR- System Renewal	3,441,592	-	3,441,592
SS- System Service	4,782,432	800,000	3,982,432
	10,906,567	800,000	10,106,567

PROPOSED N.P.E.I 2016 CAPITAL BUDGET PROGRAM

As in previous years, the NPEI 2016 Capital Budget will continue 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 cyclic programs drive Rebuild/Reinforcement/Voltage Conversion Construction as a result of, Pole Testing & Inspections, Pad-mounted Equipment Inspections, Sub-station Testing & Inspections, Manhole & Sidewalk Vault Inspections, Kiosk Inspections, Minor System Betterments, Subdivision Connections, and Demand Based System Expansions for Commercial Development.

1. **Expansions and Reinforcement of the N.P.E.I. 13.8 K.V. / 27.6 K.V. Primary Distribution System to accommodate load growth & reliability requirements.**
   - **Dorchester Road--McLeod Road to Dunn Street** **Investment Category SR**

   Rebuild Project which targets 1.0 K.M. of urban distribution line installed in 1955, including 26 pole changes, new three phase (1.0KM) primary and secondary (1.0KM) circuits, 5-1Ph & 3-3 Ph distribution transformers replacements resulting in the upgraded supply to about 74 residential & 7 Commercial customers directly. System benefits include replacement of aging equipment, future source for voltage conversions opportunities in the immediate area, improved equipment clearance, and increased Customer reliability and capacity increase.

   Estimated cost: $ 531,911.70 ***-- NF Service Area Project #2016-0001***

2. **Oakwood Drive--Pole #111-25 to Pole #98-7** **Investment Category SS**
   Project scope involves replacement of 1.5 KM. of an urban overhead primary distribution line, with an overhead 15 KV 600 amp class main 3-phase line in the same alignment as the existing. Installation of 25-new 50' wood poles, 7-Single Phase, 2-Three Phase transformers, transfer 3-three phase & 1-Single Phase Underground Primary Risers, and transfer 24-existing Residential triplex services. Since the original install this section of line has changed function from a radial feed, and has been incorporated into a tie between 2-Transformer Stations, without re-conductoring to facilitate the ampacity increase. System benefits include the replacement of aging equipment originally installed in 1970, system loss reduction, improved reliability, and capacity increase.

   Estimated Cost= $ 611,939.67 ***-- NF Service Area Project #2016-0002***

3. **600 MCM U/G Install--Glenholme to Franklin Ave** **Investment Category SS**
   Project scope involves the installation of 150M of 600MCM Underground 15 KV primary cable to complete an inter-tie between two recently completed system rebuild/upgrades. Installation of 100m of new concrete encased duct bank tied into 50M of existing duct bank, install 160M x 3 of 600mcm underground primary cable and completion of 2-primary risers. System benefits include increased flexibility during failure contingency periods, and the ability to reconfigure the system based on the results of optimization studies using system modeling software.
   Estimated Cost= $ 133,262.22 ***-- NF Service Area Project #2016-0003***

4. **Willoughby Drive--Main Street to Cattell Drive** **Investment Category SR**
   Project scope involves the replacement of 0.7 KM. of urban overhead 13.8 KV primary line installed in 1960 with 16-new 45’ wood poles framed for 3-phase, 10-new 40' wood poles framed for single phase and re-conductor the existing 3/0 Lum with 556 MCM 3-phase main circuit, constructed in the same alignment as the existing pole line, install 7-single phase & 1-three

phase transformer to replace existing, install 0.7KM of secondary buss, and transfer of 34 services to the new buss. Benefits include improved system losses, improved equipment clearances, reinforcement & capacity increase of the main distribution line.

Estimated Cost= $ 369,270.50 ***--NF Service Area—Project #2016-0004***

5. **Willoughby Drive-- Cattell Drive to Weinbrenner Road** **Investment Category SR**
Project scope involves the replacement of 0.7 KM. of urban overhead 13.8 KV primary line installed in 1969 with 21-new 45' wood poles framed for 3-phase & 10-new 45' wood poles framed for single phase to establish a new 1-ph tie to Willick Road. Replace the existing 3/0 Lum with 556 MCM 3-phase main circuit, constructed in the same alignment as the existing pole line, install 5-single phase & 1-three phase transformer to replace existing, install 0.7 KM of secondary buss, and transfer of 30 services to the new buss. Benefits include improved system losses, improved equipment clearances, reinforcement of supply to a sensitive load (large Senior Care Facility) and new single phase back-feed.

Estimated Cost= $ 380,290.07 ***--NF Service Area—Project #2016-0005***

6. **Pad-mounted Switchgear Replacements** **Investment Category SR**
The Underground Equipment Inspection Program has identified a requirement for replacement of air insulated pad-mounted switchgear units, with dead-front stainless steel enclosure SF-6 Gas Insulated Equipment, due to corrosion and contamination issues, which will continue at a rate of 3-Units per year. 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= $ 250,000.00 ***-- NF Service Area Project #2016-0006***

7. **O/H to U/G Conversion-Rolling Acres Sub. Ph III** **Investment Category SR**
The final stage of the project scope involves the relocation of primary facilities located on an inaccessible rear lot pole line within private property, for which easement documentation is available. Installation of 2.0KM of Primary duct by directional boring methods to 9 pad-mounted transformers placed on precast pads within the Road Allowance. Secondary laterals will be directionally bored back to the rear lot easements, to source the 100 individual underground house services currently fed from junction boxes mounted on the distribution poles. The streets included within this Phase include Potter Heights, Cambridge St., McColl Dr., and Rolling Acres Drive & Rolling Acres Cres. & Wiltshire Blvd. The current equipment was installed in 1958 and tree growths, pool, shed and fencing installations, have made the line difficult to maintain and service. There have been many issues in this subdivision during Ice/Wind Storm events. 15KV rated equipment will be installed for voltage conversion, once this phase has been completed. Improved Public safety, equipment accessibility, capacity increase, and voltage conversion are benefits realized through this Project.

Estimated Cost = $ 405,867.00 ***- - NF Service Area —Project #2016-0008***

8. **Clifton Hill Primary Upgrade** **Investment Category SA**
Clifton Hill is a famous entertainment destination within the Tourist Core of Niagara Falls. Development upgrades currently underway have presented an opportunity for the relocation of an existing switching station along with the installation of an additional unit, allowing for the introduction of an additional 200 amp 15KV circuit within the Clifton Hill Distribution Circuit,

enabling NPEI to divide the load on existing circuits between the two switching stations, facilitating capacity relief and future load growth. Project scope involves the installation of 2-manholes, 2 SF-6 Vista Switchgear, 100M (x6) of 600MCM Main Circuit, 100M (x6) of 2/0 Distribution Circuit. One of the new Switchgear will incorporate an additional un-fused way to provide for the introduction of an additional primary feeder through the development to an NPEI Circuit on Robinson Street dependant on scheduling of additional development, for which the Owner is presently installing 160M of duct-bank to facilitate the additional feeder. Benefits include improved system reliability, reinforcement & capacity increase of the distribution system within the Tourist Core.

Estimated Cost= $ 237,795.84 ***--NF Service Area—Project #2016-0009***

9. **Additional Sectionalizing Switches—8-Units** **Investment Category SR**

A review of existing feeder configurations, sourced by Stanley, Murray, Beamsville & Niagara West Transformer Stations, Kalar M.T.S. and Vineland D.S., utilizing system optimization software, has identified a need for additional pole mounted ganged load break switches within the system, minimizing system losses, providing improved contingency options during outage events, providing a means to minimize the area affected. The program will target the installation of 8 additional units.

Estimated Cost= $ 73,000.00 ***-- Combined Service Area Project #2016-0010***

10. **Frederica Street--Dorchester to Drummond Road** **Investment Category SR**

Project scope involves the replacement of 1.1 KM. of existing overhead 4.16 KV (F-104) primary line installed in 1955 with 16-new 45' wood poles & utilizing 12-existing poles previously replaced and re-conductor the existing 2/0 with 556 MCM 3-phase main circuit, constructed in the same alignment as the existing pole line, install 4-new transformers, install 1.1KM of secondary buss, and transfer of 55 services to the new buss. Installation of 2-new switchgear will enable the functionality of tie points between 4-feeders, namely the 3-M-54, 3-M-51, 12-M-31and the K-M-4. Benefits include the final stage of reconstruction to eliminate Municipal Sub-station Stn. #22 constructed in 1969, targeted for decommissioning, the provision for immediate voltage conversion opportunities of several existing lateral feeds, improved system losses, improved equipment clearances, and improved supply reliability and flexibility on the system during contingencies.

Estimated Cost= $ 671,752.81 ***--NF Service Area—Project #2016-0011***

11. **Victoria Avenue Fly Rd South Ext Ph I.** **Investment Category SS**

The Project Scope involves the overbuild of an existing 3-phase 8.2 KV primary line on Victoria Ave in place, and constructed with a 3-phase 27.6KV top circuit for approx 2.0 KM. Construction involves the installation of 32-new 45' poles, transfer of existing primary cable, and installation of 2.0KM of new 556MCM Primary and Neutral conductor from Fly Rd South to Seventh Ave. The Project is being initiated to provide a 27.6KV tie to town of Jordan Station Benefits include improved supply reliability and flexibility on the system during contingencies & system configuration by tying the F-1 Feeder from Vineland D.S to the M-5 Feeder from NWMTS. .

Estimated Cost = $ 298,861.60 ***-- PW Service Area Project #2016-0012***

12. **1-Phase Hydraulic Reclosure Upgrades—10-Units** **Investment Category SS**

Approaching end of life cycles, and relating to the 5-year Wi-Max deployment plan, a requirement has been identified, for the replacement of 10-existing pole mounted hydraulic reclosures. There are approximately 90 oil filled units in service on the system. 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. The solid dielectric insulation eliminates the oil used in the older units, making them less of an environmental concern.

Estimated Cost= $ 100,000.00 ***-- PW Service Area Project #2016-0013***

13. **Jordan Road—Voltage Conversion Ph III** **Investment Category SR**
The Project Scope involves the last stage of rebuild of existing 3-phase 8320Volt primary line, in place, constructed to 27.6KV standards for approx 2.0 KM involving the installation of 34-new 45' poles on Honsberger Rd from Jordan Rd to Thirteenth St., transfer of existing primary conductors, and installation of 2.0km of new neutral. The project was driven by the pole inspection program which has identified a high number of deteriorated cross arms supporting the primary conductors. Benefits include elimination of the identified hazard, improved equipment clearance, and conversion to 27.6KV of the feeders supplied by Jordan M.S. for its de-commissioning.

Estimated Cost = $ 335,377.35 ***-- PW Service Area Project #2016-0015***

14. **Downtown Core PILCDSTA De-Commissioning** **Investment Category SS**
NPEI has targeted lead jacketed primary cable for removal from service, due to age (installed in 1959), performance, and difficulty of performing repairs. The last section in service is located between Station #151 on River Rd and the City Hall Sub-Station located on Huron St. Project scope involves the decommissioning of 1.0 KM. of existing 500MCM PILCDTA direct-burial cable by replacement with a combination of new & existing infrastructure. 350M of new primary duct bank will be installed on River Rd. between Buttrey St. & Bridge St., and a voltage conversion of an existing underground 4.16 KV (F-64) primary line installed in 1995 from the City Hall station to the corner of Bridge Street & River Road. This 2/0 circuit, installed within a concrete encased duct bank, takes a similar route to the lead cable, and can be incorporated into the 15KV system by performing a voltage conversion and tying the 2-systems together at City Hall, and at Bridge St, since the existing 4.16KV Feeder cable is insulated to 15KV, and connected transformers are dual voltage units. System benefits include replacement of infrastructure targeted for decommissioning, the immediate voltage conversion of approx. 500 KVA of connected load from Station #6, improved system losses and performance.

Estimated Cost= $ 795,701.13 ***--NF Service Area—Project #2016-0017***

15. **Dorchester Road-- Mountain Road Riall Street** **Investment Category SS**
Project scope involves the replacement of 1.0 KM. of urban overhead 13.8 KV primary line installed in 1952 with 20-new 45' wood poles, constructed in the same alignment as the existing pole line, install of 200m of concrete encased duct-bank under a major Transmission Corridor due to clearance issues with the transmission line to an overhead line. Replacement of the undersized primary conductor with 556 MCM for increased ampacity of the circuit during contingency situations, 4-single phase transformers to replace existing, install 0.6KM of secondary buss, and transfer of 40 services to the new buss. Benefits include improved system losses, improved equipment clearances, reinforcement & capacity increase of the supply in the area.

Estimated Cost= $ 626,866.73 ***--NF Service Area—Project #2016-0018***

16. **Lightning Mitigation Measures- Investment Category SS**
The continuation of an established sustainment Program, the project scope involves the installation of additional lightning mitigation equipment throughout the distribution system within the Western Service Territory to correct deficiencies identified through recent storm related equipment failure events. Benefits include improved reliability indices, reduction in the amount of equipment damaged during storm events, improved outage restoration times.
Estimated Cost = $ 30,000.00 - -PW Service Area —Project #2016-0019

17. **NS&T Highway Double Cct. O/H Crossing Replacement Investment Category SA**
Due to a previous pole fire & future MTO widening proposals the need has arisen to replace an existing overhead single pole, double circuit 15KV primary structure crossing the Q.E.W. south of Thorold Stone Road with a double pole structure with removal of the plant located within the MTO R.O.W. This will facilitate the future widening by the MTO utilizing Grade "A" standard construction using concrete poles, increasing Public Safety by eliminating future pole fire possibilities, and constructing to present day standards with increased spacing to facilitate joint-use attachments on the structure.
Estimated Cost= $ 272,236.11 -- NF Service Area Project #2016-0021

18. **Line Relocations due to Municipal Road Improvement requirements. Investment Category SA**
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: $500,000.00 (recoverable $250,000) -- Combined Service Area

19. **Replacement of Poles identified with limited Structural Integrity. Investment Category SR**
- The natural degradation of wooden utility poles is an ongoing issue. Per the Distribution System Code, 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 is performed, with deficiencies addressed by the replacement of subject poles, in a timely manner, through this Capital Program. In the Niagara Area pole replacements are beginning to level off as cycles begin to repeat, with a structured treatment program implemented during the testing cycle to increase the poles life cycle. The 2016 Niagara test area is bounded in the West by the City Limits/Thorold Town Line Rd., South to Hwy #420/Beaverdams Road/Lundy's Lane, East to Stanley Ave and North to Thorold Stone Road and includes 1174 poles total. The Western Service Territory test area is bounded by Westbrook Road to the west, north to Twenty Road, East to Church/Allen Road, south to the Boundary line at South Chippawa Road and includes 3532 poles. The average cost per pole change is approximately $ 5,000.

Estimated Costs: $ 535,930.23 --Combined Service Area --Project #2016-1010/2010

20. **Replacement of Kiosks with Transformers, EFD & Posi-tect Switches Investment Category SR**

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 2013.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. xx-Units remain on the 15KV System, and 74-Units remain on the 5KV System. For 2016 the plan is to replace 10 to 15 units.
Estimated cost: $841,137.39 ***-- NF Service Area Project #2016-0020***

21. **System Sustainment Allowance.** **Investment Category SS**
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: $ 680,000 ***-- Combined Service Area-- Project #2016-1007/2007***

22. **Subdivisions and new residential services**

Lot servicing of existing	***$275,000***

23. **Subdivisions and new residential services**

Connection and energizing of new subs	***$312,004***
Recoverable	***($200,000)***
	$112,004

24. **Subdivisions and new residential services**

Lot connection rebates	***$150,000***

25. **Demand based system reinforcements for new commercial service connections.**
Investment Category SA

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: $1,007,500.00 ***–Combined Area-- Project #2016-1008/2008***
(Recoverable $350,000)

26. **Other Capital Expenditures as listed below:** **Investment Category SS**

Metering general	*$193,500*

27. **Other Capital Expenditures as listed below:** **Investment Category SS**

MIST Metering	*$287,360*

Project Total	***$10,906,567***
Recoverable	***$ 800,000***
TOTAL	***$10,106,567***

APPENDIX C

General Equipment

	2016 Budget
Ergonomic Office Equipment	8,843
General Equipment as needed	11,000
	19,843

APPENDIX D

Hardware

	Item	Purpose	Budget 2016
HARDWARE			
Network	Juniper firewall - Smithville	Network security	10,000
Servers	Dell LT2000 tape drives for Smithville and Niagara Falls	Improved backup system from using tape	12,000
	Server	Backup SQL server	20,000
	Server / VM additions	New requirements	40,000
Printers	Replacement of T620	Replacement of current T620	2,500
	Lexmark		650
Phones	Professional Services	Integration of phone system to CIS/Outage Management/IVR	25,000
	Professional Services & Hardware update	IVR upgrade due	65,000
	Cell phones	Cell phones add/replace	3,250
	Mitel Headset	Ease of answering calls hands free	1,100
	Office phones required (3 5330 IP phone (backlit) + UC Basic User (3 license) + Professional services)	Add as required	1,200
PC / Monitor	PC Replacements	Add PCs as required	12,200
	Field Durable Laptops / Tablets	Deployment of Inservice field use in Operations, and mcare in Metering	39,200
LCD Projectors	NEC VT595 XGA 2000 ANSI LUNCENS PROJECTORS		1,000
Equipment	Mail machines (smaller units)	Niagara Falls	10,000
TOTAL HARDWARE			**243,100**

APPENDIX E

Software

	Item	Purpose	Budget 2016
Network	Blue coat SSL Appliance and packeteer appliance - 2nd layer malware	Network security	50,000
	Backbox backup software	Back up solution/DR	10,000
	SQL server licensing	Network infrastructure	15,000
	vCenter servers - 2 windows 2008 licenses	Network infrastructure	3,000
Disaster Recovery testing	Zerto - VM testing and managing VM failover	Disaster Recovery	40,000
	Double take - Physical server DR failover	Disaster Recovery	20,000
Customer Service	Alertworks	Automated voice call back and survey for power outage, collections, scheduled maintenance	11,000
Engineering and Operations	Work Management/Outage Management Intergraph solution including software and professional services for installation and training	Work/Outage Management - TA module including primary and redundant including professional services	65,000
Engineering and Operations	Work Management/Outage Management Intergraph solution - Any new requirements	Work/Outage Management	35,000
Engineering and Operations	Spot sheet replacement	Work/Outage Management	45,000
Engineering & HR	Visio Licenses		800
	Adobe Read/Write license	New requirement	2,000
Customer Service	CIS - customer presentment	New requirement	35,000
	Harris Northstar Professional Services	Miscellaneous as required	25,000
TOTAL SOFTWARE			**356,800**

APPENDIX F

Vehicles and Transportation Other Equipment 2016

Description	2016 Budget
<u>Vehicles < 3 tonnes</u>	
Replace SV# 22 2008 4X4 Chev	45,000
Replace NF#14 2004 Dodge Ram	45,000
Total	90,000

<u>Vehicles > 3 tonnes</u>	2016 Budget
Replace Backhoe with Bobcat Skid Stear	60,000
Replace #43 1996 Material 46' Handler	330,000
Replace # 33 1993 RBD	360,000
	750,000

<u>Transportation Equipment</u>	2016 Budget
	-

APPENDIX G

Tools Budget 2016

Tools and Equipment for Vehicles	2016 Budget
Various replacement tools for budgeted new trucks	12,142
Miscellaneous Replacement Tools	37,454
	49,596

Tools for Garage	
Various other shop tools	10,404
Compressor for Garage	10,000
Total cost of equipment purchase for 2015	20,404
Total Tool Budget	70,000

APPENDIX H

Communication Equipment

	2016 Budget
Material Campden Tower	74,000
NF Tower Planning and Design	76,000
Total	**150,000**

Niagara Peninsula Energy Inc.
Capital Budget 2011 - 2019
(000's)

	Actual 2011	Actual 2012	Actual 2013	Actual 2014	Projected 2015	Per Settlement Approved in Rate App 2015	Proposed Budget 2016	DSP 2017	DSP 2018	DSP 2019
Land and Land Rights	0	5	1	0	0	0	0	0	0	0
Buildings & Fixtures	122	626	572	1,613	474	87	87	0	0	0
Sub Total	122	631	573	1,613	474	87	87	0	0	0
Distribution Station	800	684	501	514	1	0	0	439	0	0
Transformer Station	0	0	0	16	0	0	0	400	0	0
Overhead Distribution	3,912	3,663	4,786	4,362	4,933	4,505	4,633	5,321	5,792	6,310
Underground Distribution	2,783	3,148	2,476	3,470	2,925	3,514	4,292	2,775	2,779	2,448
Distribution Transformers	1,064	1,247	1,371	1,135	1,323	1,547	1,410	1,325	1,533	1,560
Meters	177	171	193	396	255	285	285	224	224	224
Smart Meters	615	786	82	2,049	0	143	287	200	200	200
Capital Contributions	(1,664)	(1,585)	(991)	(1,388)	(2,238)	(828)	(800)	(775)	(775)	(775)
Sub Total	7,687	8,114	8,418	10,554	7,200	9,166	10,107	9,909	9,753	9,967
Office Furniture & Equipment	69	112	170	177	26	33	20	20	20	35
Computer Equipment, Hardware	250	371	276	279	240	240	243	246	241	236
Computer Software	194	213	115	538	316	369	357	265	281	453
Vehicles < 3 tonnes	350	104	158	0	236	114	90	111	142	77
Vehicles > 3 tonnes	189	1,057	1,172	631	254	514	750	637	442	450
Vehicle Other	0	0	0	21	0	71	0	0	22	0
Vehicle Disposals	0	0	0	(441)	(377)	(314)	(498)	0	0	0
Stores Equipment	10	32	0	32	54	0	0	0	0	0
Tools, Shop & Garage Equipment	78	133	83	60	68	61	70	71	55	56
Measurement & Testing Equipment	15	0	0	0	0	1	0	1	1	1
Communication equipment	1	332	344	228	68	215	150	215	215	215
Miscellaneous equipment	0	0	0	0	0	1	0	1	1	1
Sub Total	1,156	2,354	2,318	1,526	886	1,305	1,181	1,567	1,419	1,526
Total Capital before smart meter additions from prior years	**8,965**	**11,098**	**11,309**	**13,693**	**8,560**	**10,558**	**11,375**	**11,476**	**11,172**	**11,493**
Non-recuring Capital Expenditures										
Wire Building & High Mass Lighting	0	0	1,340	0	0	0	0	0	0	0
	0	0	1,340	0	0	0	0	0	0	0
Net Capital Expenditures	**8,965**	**11,098**	**12,649**	**13,693**	**8,560**	**10,558**	**11,375**	**11,476**	**11,172**	**11,493**

Average Net Capital Expenditures excluding non-recurring- 5 year	**10,725**	10 Year Averag	**9,914**
Average Net Capital Expenditures including non-recuring 5 year	**10,993**	10 Year Averag	**10,048**
Average Fixed Asset additions COS rate Application 2015 net of average $850K capital contributions	**10,558**	2015 COS	**10,558**

Appendix 1-7

NPEI 2015 Capital and Operating Budgets

niagara peninsula energy

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2015 BUDGET

- **2014 Projected Capital**
- **2014 Projected Financial Statements**
- **2015 Capital Budget**
- **2015 Operating Budget**

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Niagara Peninsula Energy Inc.
Budget Report 2015

This report is prepared for the purpose of reviewing the significant factors affecting the 2014 and 2015 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.

Basis of Presentation

The 2015 Budget Balance Sheet and Budget Income Statement with 2014 comparative figures have been prepared using the Canadian Generally Accepted Accounting Principals (CGAAP). There have been no adjustments made for the International Financial Reporting Standards (IFRS).

The Accounting Standards Board (AcSB) issued an option for rate regulated entities to defer the implementation of IFRS to January 1, 2013 in March 2012. In July, the Ontario Energy Board issued a Letter of Direction stating "The Board however will require that these changes be mandatory in 2013 (i.e., effective on January 1, 2013) for those distributors that do not elect to make these accounting changes in 2012 regardless of whether the AcSB permits further deferrals beyond 2012 for the changeover to IFRS."

The most significant impact of IFRS to NPEI is the estimated useful lives of fixed assets. IFRS requires a review of an entities policy for estimating fixed asset useful lives to be in accordance with various criteria versus the OEB's policy related to fixed asset useful lives which is 25 years. As a way of achieving the OEB's letter of direction noted above without formally adopting IFRS effective January 1, 2013, many LDC's are opting to change their accounting policy for fixed assets and depreciation effective January 1, 2013.

The Board authorized a new regulatory variance account to Account for Changes in Accounting under CGAAP so LDC's will be eligible for the IFRS interim standard as first time adopters. This new variance account will record the difference in depreciation expense using the new estimated useful lives of the now componentized fixed asset balances.

The change in useful lives results in a change in Accounting Policy for Fixed Assets and Depreciation with an effective date of January 1, 2013. By adopting this change in accounting for useful lives NPEI achieves the same effect mandated by the OEB as noted above.

In 2012, NPEI completed the componentization and determination of useful lives in accordance with the Board's regulatory accounting policies as set out for modified IFRS as contained in the *Report of the Board, Transition to International Financial Reporting Standards,* EB-2008-0408, the Kinectrics Report, and the Revised 2012 *Accounting Procedures Handbook for Electricity Distributors* ("APH") with the assistance of KPMG.

In 2013, NPEI completed the segregation of the opening cost and accumulated depreciation balances due to componentization and recalculated depreciation expense using the new depreciation lives in accordance with the report identified above. The difference between the calculation of depreciation expense using the OEB's 25 year life and the new useful lives was recorded to the new variance account noted above in 2013.

For example, overhead was previously categorized between poles and wires and both were depreciated over 25 years. After componentization of overhead, poles were segregated between wooden poles and concrete poles where wood poles will now have a useful estimated life of 50 years and concrete poles will now have a useful estimated life of 60 years.

The current distribution rates are calculated using the OEB's 25 year life. As a result of componentization and changing the estimated useful lives, the depreciation expense is much lower. The offset to the regulatory liability account is presented as a Regulatory Debit on the Income Statement and as a result there is no impact on Net Income before PILS. The OEB requires LDC's to record this difference to the new variance account and dispose of its balance the next time the LDC submits its cost of service rate application. An LDC's future rate application will be prepared on the basis of the new estimated useful lives when rates are calculated. NPEI has estimated a $6.4 million balance to be refunded to its customers related to the change in estimated useful lives. This balance along with a calculated return on rate base was applied for in the 2015 Cost of Service rate application. NPEI has applied for a two year repayment period commencing May 1, 2015.

In September 2012, the AcSB issued another option to defer the implementation of IFRS to January 1, 2014. NPEI has opted to defer the implementation of IFRS to January 2014 unless another deferral option is issued by the AcSB and change its accounting policy for fixed assets and depreciation effective January 1, 2013.

On January 31, 2014, the IASB published IFRS 14 *Regulatory Deferral Accounts.* For purposes of simplicity the presentation of the 2014 and 2015 financial statements are under CGAAP.

NPEI has prepared the 2014 projected financial statements and the 2015 budgeted financial statements using the new estimated useful lives for fixed assets.

2014 Highlights

2014 Projected Balance Sheet

Total assets are projected at $173.5M, which is up 2% or $3.6M from the 2013 total assets. This is mainly due to a net increase in fixed assets of $7.6M. Included in net fixed assets is $1.6M of smart meter expenditures that were previously recorded in the smart meter regulatory asset account.

Cash is projected to be down by $2.6M from 2013. NPEI issued a request for proposal (RFP) to five major banks and one credit union in September 2014. Two of the banks did not submit a proposal. TD bank was awarded the RFP and issued NPEI a $10M long term loan for 5 years with only interest repayments on November 13, 2014. The interest rate was 2.663%.

Accounts receivable are projected to be up by 4% mainly due to the increase in the cost of power, network, connection, wholesale market and global adjustment charges.

Capital Additions 2014

Total gross capital expenditures excluding smart meters are projected at $13.4M, offset by capital contributions of $1.0M for a net of $12.38M. The 2014 capital budget was $12.886M which is $0.5M higher than the projected 2014 expenditures. Also, five vehicles that reached their end of life and have since been replaced were disposed of from the fleet inventory.

The 2014 distribution asset additions are projected to be $106K less than budget.

Significant capital projects excluding capital contributions completed in 2014 are as follows:

Project Name	2014 Budget	2014 Projected
Demand based system reinforcements for new commercial services	1,410,778	2,147,098
Replacement of Poles identifed with limited Structural Integrity	778,702	425,941
OH to UG Primary Conversion-Rolling Acres Subdivision Phase 1	768,694	278,117
U/G Primary Extension-Weightman Brigde Chippawa	701,810	805,159
Replacement of Submersibles & Kiosks with EFD switches and posi-tects	624,457	289,523
Replacement of Transformers with >50PPM PCB Content	566,479	362,070
Line Relocations due to Municipal Road Improvement requirements	520,355	728,530
Crawford St. Area Rebuild	516,557	61,190
Overhead line rebuilds of facilities identified by Pole Inspection Survey	516,513	560,625
3-M-28,3-M-26 & 3-M-29 Feeder Replacement	417,731	442,826
System Sustainment Allowance	400,000	975,580
Jordan Road- Red Maple to the QEW	397,516	314,763
12-M-6 Replacement-Simcoe St./Buckley/Armour St.	372,631	275,607
Dorchester Rd.-Garden Street to McMillan Drive	362,018	534,005
Fallsview Boulevard - Ferry to Robinson	332,173	-
Wholesale Meters	300,000	362,980
Municipal Sub-station Rehabiliation	252,037	297,499
Subdivision Connection and energizing of new subs	200,000	627,379
Subdivision Lot servicing of existing	200,000	338,743
Lot connection rebates	150,000	125,000
Metering General	130,000	102,161
King Street- 27.6kV Extension to Martin Rd.	112,554	10,000
Pad-mount Switchgear Replacements	110,057	119,478
Additional Sectionalizing Switches - 8 Units	100,000	114,694

Significant demand projects include the Jordan Station transformer, Morrison Street development, Hopcan, Optimist Square, Hornblower, Lowes plaza, NRP building, Freeman Herb, Beamsville arena, and the HAP wind project.

Building expenditures projected at $1.4M include the construction of the workspace optimization and operations department relocation project as well as the redesign and construction of the stores area at the Niagara Falls location. The high mast lighting project is estimated at $263K and was completed in 2014.

Office furniture additions of $158K mainly include office furniture for the new operations area and various security cameras.

Computer hardware additions are projected at $269K. This includes the replacement of servers and PC’s which are at end of life and the purchase of Fujitsu scanners to be used for File Nexus in Engineering and CDM.

Computer software additions are projected at $443K. Customization of File Nexus for Engineering, CDM and HR, Great Plains upgrade to GP2013, Harris automation platform, Appollo workflow form upgrades, Cognos reports, Malware protection and Exchange migration are included in the software additions in 2014.

Vehicles > 3 tons included a 55' double bucket material handling aerial man lift truck for $328K, and a 46' material handling aerial man lift truck for $307K. Four large trucks and one small truck were disposed of in 2014 due to age, condition and maintenance costs.

NPEI began a strategic investment into the development of a smart grid. Included in communications equipment expenditures of $258K is a pilot Wi-max project. The project consists of a three-pronged approach, involving; the installation of backup DC power systems; the installation of a wireless communications network and the upgrade of archaic electromechanical equipment with modern electronics.

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 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.

The backup DC power systems and communications network constitute the backbone of the smart grid. Both fundamental components will enable the continued addition of modern electronics to the distribution system for the foreseeable future. The DC systems are required to power both the communications network and modern electronics. It will also provide an uninterrupted power source during system outages.

Each electronic device added to the distribution system represents an opportunity to improve power quality, efficiency, reliability, security and safety by:

- Enhancing monitoring, control and diagnostics functionality,
- Improving NPEI's ability to identify and respond to problems more quickly,
- Introducing distribution system automation,
- Improving the quantity and quality of information available,
- Allowing greater flexibility in system configuration,
- Enabling the ability to implement condition-based maintenance,
- Establishing a communications platform capable of supporting real-time system modeling and analysis.

Added-value is achieved for the customer by:

- Improving operational efficiency,
- Reducing the duration and frequency of outages,
- Establishing a communications platform capable of supporting advanced secondary services,
- Establishing a communications platform capable of dealing with next-generation loads and substantial penetration of green energy, and
- Improving the availability and accuracy of information.

Liabilities and Share Holders Equity 2014

Current liabilities are projected to be $21.2M at the end of 2014. This is a decrease of $3.8M. The water billing, collecting and customer service activities returned to the City of Niagara Falls in May 2014. In May 2014, the final payable balance to true up all water related accounts was paid to Niagara Falls Hydro Services Inc. which was the affiliate company performing the water billing, collecting and customer services activities on behalf of NPEI for the City of Niagara Falls.

Accounts payable are projected to be $2.6M higher due to a projected increase in the power bill.

Regulatory Liabilities are projected to be $0.5M higher in 2014 than 2013. This increase is mainly due to the new variance account for changes to accounting policies under CGAAP which represents the difference in changing the estimated useful lives of NPEI's fixed assets. The increase is the estimated difference in depreciation for 2014. NPEI has applied to the OEB in its 2015 Cost of Service rate application to refund this balance to its customers over a two year period. The increase in Deferral Account related to Accounting Policy changes was offset by a decrease in the Retail Settlement Variances accounts mainly due to the increase in Global Adjustment.

NPEI filed its final disposition for smart meters rate application in September 2013. The rate application was approved in February 2014. The smart meter costs included in the Smart Meter Regulatory Asset account that related to previous years were reallocated to fixed assets in the amount of $1.6M net of accumulated depreciation. Also, net smart meter revenues related to previous years in the amount of $875K were reallocated to the income statement. The balance remaining the smart meter regulatory asset account mainly includes the net book value of stranded meters. These costs were applied to be disposed of in the 2015 CoS rate application over a period of two years.

Long-term liabilities are projected at $59.3M which is up by $6.5M over 2013. NPEI obtained a five year, loan in the amount of $10M in November 2014 at a fixed rate of

2.663% with interest only repayment terms. Principal repayments of $1.9M related to existing debt were made in 2014.

The Ontario Provincial Government mandated all LDC's to achieve an energy savings target and a demand savings target by December 31, 2014. NPEI submitted a CDM Strategy on November 1, 2010 in accordance with the CDM code for Electricity Distributors (ED-2010-0215). NPEI's energy savings target is 58,040,000 kWh and its peak demand reduction target is 15.49 MW. The OEB regulates the CDM programs and targets for each LDC. NPEI commenced implementation of the provincial programs for Residential, Commercial, Industrial and Home Assistance customers in 2011. NPEI continued implementing CDM programs in 2014.

In 2014, NPEI paid a total dividend of $1,200K to its shareholders proportionate to the shares held.

2014 Projected Income Statement

NPEI completed the Cost of Service Rate Application process in May of 2011 with rates effective June 1st, 2011. The final Base Revenue Requirement amounted to $29,014,020 which included a revenue deficiency of $2,064,398. The next Cost of Service ("CoS") rate application was submitted to the OEB in 2014, with rates effective May 1, 2015. NPEI followed the Incentive Rate Mechanism (IRM) process for the interim period between 2012 and 2014. NPEI's IRM rate application was submitted to the OEB in August 2013 for rates effective May 1, 2014.

Projected net income after taxes is estimated at $1.6M, which is $1.4M higher than budget and $137K higher than 2013. The 2014 budget did not include the smart meter net revenues of $875K related to prior years.

NPEI has presented the Deferral and Variance rate rider related to refund/collection of PILS as explained above as an Extraordinary Item. The rate rider was in effect from October 1, 2012 to April 30, 2014.

Regulatory Net Income does not include the depreciation expense for the FMV bump of $1,099K. Projected 2014 regulatory net income before the extraordinary item related to the deferral and variance rate rider for PILS and income tax is $4,842K.

Gross profit percentage is projected to be 1.75 pts. above the 2014 original budget.

Gross profit before other revenue is projected to be $3.0M over budget and 2013. This increase is mainly due to the smart meter recoveries related to prior years in the amount of $2.3M. Also, the two smart meter rate riders; SMDRR (Smart Meter Disposition Rate Rider) and SMIRR (Smart Meter Incremental Revenue Requirement) are included in the service charge revenue.

Other revenues are projected $329K higher than budget. Other revenue includes carrying charge revenue related to smart meter recoveries from prior years in the amount of $130K. Interest charges on late hydro payments are projected to be over budget by $58K. Other revenue is projected to be lower than 2013 mainly due to the water activities returning to the City of Niagara Falls in May 2014.

Cost of power is projected to increase over 2013 by $7.2M or 6%.

Projected Operating expenses are estimated to be above budget by $1.2M or 5% and above 2013 by $3.0M or 13%. Included in the 2014 projected expenses are the following expenses related to smart meter costs from prior years;

Operations- Distribution expenses	$ 81K
Administration expenses	$ 59K
Billing and Collecting expenses	$1,142K
Depreciation expense	$ 273K
Total Smart meter expenses prior years	$1,555K

In prior years, NPEI's two smart meter coordinators labour and benefits as well as the smart meter reading costs were recorded in the smart meter regulatory asset account and presented on NPEI's balance sheet. Following the final disposition of smart meter costs these 2014 expenditures are recorded in the income statement. As a result the two smart meter coordinators labour and benefits and the 2014 meter reading costs are included in the current years' statement of operation for a total of $415K. These costs were not budgeted for on the income statement in 2014 but were accounted for in the regulatory asset account pending approval of the smart meter rate application.

Distribution operating expenses are projected at $80K, or 1% over budget and $378K, 6% higher than 2013. Included in this variance is the $81K related to smart meter costs from prior years.

As part of the stores area renovation which was budgeted for 2014, NPEI engaged a consultant in 2013 to review the current practices, processes and resources used in the purchasing, receiving, issuance and accounting of inventory. The current stores practices and processes have been the same for the last 30 years. The consulting firm was also engaged to aid with the implementation of the various changes in practices, processes and resources that were found in their initial review. Benefits include; reduced rework, increase availability of resources, greater quality assurance, enhanced productivity, strategic arrangements with suppliers, lower supplier costs, less waste, effective management reports, clear expectations, improved space design and reduced dependency on "tribal knowledge". NPEI continued the implementation of the change in processes throughout 2014. NPEI developed an electronic material movement form which will automate the request for materials electronically from the laptops in the trucks to the stores warehouse.

NPEI also will complete the testing for PCB's in the transformers in the former Peninsula West service area by the end of 2014.

Administration and General Expenses are projected to equal budget and be $406K or 6% higher than 2013. Interest expense is $147K higher in 2014 due to the 2013 loan financing was outstanding for a full year in 2014 versus one month in 2013 and NPEI obtained additional financing in November 2014. Maintenance expenses are $75K higher in 2014 versus 2013 due to snow plowing of a larger yard area and increased building maintenance expenses. Legal fees and consulting expenses are projected to be $82K higher in 2014 versus 2013. NPEI's controller returned from a maternity leave in June 2013, as a result salaries and benefits are recorded for a full year in 2014 versus 7 months in 2013.

Billing and collecting expenses are under budget by $403K or 8% after the impact of smart meter expenses are removed. The 2014 budget included the water billing activities to return to the City of Niagara Falls in April 2014. After the smart meter impact is removed from 2014, billing and collecting expenses are $351K higher than 2013. The increase is mainly due to the water billing, collecting and customer services costs that were previously allocated to the affiliate company in 2013 for a full year were only allocated for four months in 2014.

Depreciation is less than the 2014 budget by $70K and higher than 2013 by $324K. The 2014 projected depreciation includes $273K of depreciation expenses related to smart meters from prior years. Depreciation expense of $56K related to stranded meters is also included in 2014.

2015 Highlights

In 2014, NPEI was scheduled by the OEB to submit its next 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; Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance.

NPEI's overall business strategy is to integrate with the four outcomes 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.

NPEI engaged a third party to perform a customer survey in 2014. The results of the survey were incorporated into NPEI's development of its DSP and rate application.

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 is over 650 pages and includes an Asset Condition Assessment ("ACA") which was performed by Kinectrics, NPEI's asset management process, and a very detailed five year capital expenditure plan.

NPEI developed its' operational, maintenance and general administration ("OM&A") distribution expenses based on the four outcomes noted above. The 2015 OM&A distribution expenses applied for in the CoS rate application total $17,042K excluding interest expense and depreciation. Depreciation expense included in the rate application totals $4,937K. NPEI prepared its 2015 Budgeted Income Statement based on the CoS rate application submitted to the OEB in September 2014. 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 2015 Distribution Revenue is based on the rates applied for in the rate application effective May 1st, 2015.

NPEI's distribution expenses excluding the smart meter expenses from previous years, interest expense and depreciation is projected at $15,801K in 2014.

Distribution expenses	$ 291K
Administration & general	$ 147K
Billing & Collecting expenses	$ 827K
	$1,265K

NPEI's current collective agreement expires March 31, 2015. For purposes of preparing the rate application and the 2015 budget, the rate application estimates a 2.5% wages and benefits increase and a range of 1 to 2% increase in OM&A expenses depending on the type of expense.

The main cost drivers are the wage increase, the replacement of a systems analyst, labour and other fixed expenses related to water billing, collecting and customer services activities no longer recovered, outsourcing of mailing activities, meter reading costs related to MIST meters.

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 has included $132K in 2015 related to MIST meter reading costs.

In conclusion, NPEI has continued to maintain the level of distribution expenses excluding the impact of water activities and still provide safe reliable electricity to its customers using a proactive preventative maintenance approach. NPEI's continued investments in its' employees, distribution infrastructure, capital fleet and technology will result in the company' 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.

2015 Budget Balance Sheet

Total Assets are budgeted at $176M which is $2.0M or 1% higher than projected total assets. Net capital additions total $5.7M. Cash has decreased by $2.6M which is due to the 2015 capital investment, principle repayment of existing loans in the amount of $1.0M.

NPEI included a dividend payment of $1.2M in the 2015 budget.

Gross capital additions related to the distribution system are budgeted at $12.5M, net of capital contributions of $0.8M for a total of $11.7M.

2015 Major Capital projects include:

Project	Gross Capital Investment	Capital Contribution	Net Capital Investment
Crawford St. Area Carry	282,324	-	282,324
Beck Road	144,237	-	144,237
Willodell Rebuild	310,710	-	310,710
Willoughby Drive	372,191	-	372,191
Willoughby Dr Extension	383,293	-	383,293
Switchgear	250,002	-	250,002
Rolling_Acres	570,500	-	570,500
NWTC Metering	289,605	-	289,605
Sectionalizing	73,000	-	73,000
Frederica	676,144	-	676,144
NPC	818,905	-	818,905
Reclosers	100,000	-	100,000
PCB TX Changeouts	495,104	-	495,104
Jordan Ph 2	449,324	52,800	396,524
King St. 27.6kV Ext at Martin	114,460	-	114,460
Lightning Mit.	30,000	-	30,000
Road Relocation	500,000	125,000	375,000
Pole Changeouts	431,729	-	431,729
Station 22 Loads S of Pew Carry	143,724	-	143,724
Station 22 Loads N of Pew	507,139	-	507,139
Kiosks	647,029	-	647,029
Sustainment	680,000	-	680,000
Subdiv Lots	275,000	200,000	75,000
Subdiv Conn	312,004	-	312,004
Lot Rebates	150,000	-	150,000
Demand	1,007,500	450,000	557,500
Metering	193,500	-	193,500
MIST meters	143,150	-	143,150
Totals	10,350,575	827,800	9,522,775

Detailed descriptions of these capital projects can be found in the 2015 Capital projects section. See Appendix B.

Other Capital Additions

Building

In 2015, NPEI has included $220K for paving of the new surface area on the south side of the building in Niagara Falls.

General Equipment

The replacement of a ten year photocopier, control room workstation, and ergonomic office equipment mainly comprise the general and equipment budget. See Appendix C for details.

Hardware & Software

The Information Technology capital expenditures for 2015 continue to ensure that business goals are aligned to technological solutions. NPEI's network infrastructure will be optimized allowing for improved business uptime and resiliency.

The hardware and software requirements within each area allow for the following goals to be met:

- Effective and efficient business processes
- Support of risk and compliance management processes and methodology (enabling a methodology, not defining)
- Integrated, reliable, enterprise solutions
- Network integration and security
- Embedded business continuity practices, and continued update and testing of a Disaster Recovery Plan

Spending of hardware will be managed with greater emphasis on network infrastructure and disaster recovery and new business requirements.

Hardware

The following outlines the proposed 2015 costs. Costs are related to the following projects/business need:

- Improved Network Infrastructure resulting from the purchase of backup switches and servers; consultations on optimization and disaster recovery.
- Upgrade of PC's and monitors and laptops due to age and use

- Hardware server requirements in conjunction with the implementation of a bar coding software solution in the supply chain management processes
- Barcode servers and handhelds, and SCADA servers

Software

Software required for business process improvement projects and new requirements, which promote efficiency and reliability including the following:

- Optimization of stores and inventory management through implementation of bar code software solution
- Upgrade billing software to version 6
- SCADA system
- Work Management/Outage Management Intergraph solution including software and professional services for installation and training.

In review of the business requirements put forth and determination of what software is considered as part of the capital budget, key areas are reviewed. Customer engagement is of high importance.

Hardware and software solutions proposed allow for the following goals to be met:

- Effective and Efficient Business Processes enabling our business units to meet customer need and preference.
- Support of risk and compliance management processes
- Integrated, reliable, enterprise solutions: key drivers in determination of how we enable home energy management systems, making customer information available.
- Network Integration and Security: ensuring customer data is secured; however, available within a third party or web base/ mobile application. Appropriate cyber security and privacy standards must be met.
- Embedded business continuity practice: assurance of reliability

NPEI remains customer focused. Through technology, customer service surveys, customer feedback on-line forums, NPEI is prepared to undertake activities that will allow us to understand customer's preferences and to address these preferences. Whether it is data access, support of distributed generation through streamlined processes, online application support or ease of access of customer consumption data and generation, information technology investments will allow NPEI to provide information and education to customers. Customers will be able to make decisions affecting their electricity costs with the access to real time data and behind the meter services and applications. NPEI itself will have opportunities for operational efficiencies through the use of data analytic tools and automated platforms.

See Appendices D and E for details related to the hardware and software budgets.

Vehicles

NPEI has included the replacement of one large bucket truck and several small vehicles in the 2015 budget. See Appendix F for details.

Stores, Tools and Communication Equipment

Tools in the amount of $68K for the garage and fleet are detailed in Appendix G.

Communications

NPEI commenced the Wi-max pilot project in 2012 as noted above. The proposed 2015 Communications budget is for an expansion of this project for $215K.

Recommendation:

Senior management developed the capital and operating budgets extensively and respectfully recommends approval as follows:

1. The 2015 Capital budget of $11,674,000 be approved, this is comprised of net distribution additions of $9,523,000, information technology, fleet and communication expenditures of $1,931,000, and building expenditures of $220,000.

2. The 2015 total operating expenditures in the amount of $25,792,000 including depreciation and depreciation related to the fair market value bump are approved.

Niagara Peninsula Energy
Projected Balance Sheet
As at December 31, 2014
(000's)

	Projected 2014	Actual 2013	$ Variance	% Variance
ASSETS				
Current Assets				
Cash	8,889	11,481	(2,592)	-23%
Accounts Receivable	11,001	10,538	463	4%
Unbilled Revenue	15,685	16,626	(941)	-6%
Due from Affiliated Companies				
Peninsula West Services	2	2	(0)	-5%
Payments in lieu of corporate taxes refundable	384	1,521	(1,137)	-75%
Inventories	1,769	1,622	147	9%
Prepaid Expenses	871	829	42	5%
	38,600	**42,619**	**(4,019)**	**-9%**
Fixed Assets				
Land and land rights	2,963	2,963	0	0%
Buildings	16,989	15,349	1,640	11%
Distribution Stations	9,373	8,868	505	6%
Transformer Station	6,576	6,560	16	0%
Distribution lines				
Overhead	96,416	92,207	4,209	5%
Underground	83,986	80,809	3,177	4%
Distribution transformers	39,846	39,070	776	2%
Distribution meters	9,853	7,593	2,260	30%
Trucks and Equipment	21,244	19,541	1,703	9%
	287,246	272,961	14,286	5%
Less: Accumulated Depreciation	(153,391)	(146,703)	(6,688)	5%
	133,855	**126,258**	**7,597**	**6%**
Future payments in lieu of taxes	**1,081**	**1,081**	(0)	0%
TOTAL ASSETS	**173,536**	**169,957**	**3,579**	**2%**

Niagara Peninsula Energy
Projected Balance Sheet
As at December 31, 2014
(000's)

	Projected 2014	Actual 2013	$ Variance	% Variance
LIABILITIES				
Current Liabilities				
Accounts Payable	16,563	13,981	2,582	18%
Due to Niagara Falls Hydro Services Inc.	0	6,913	(6,913)	-100%
Deferred Capital Contributions	6	192	(186)	-97%
Deferred OPA revenues	373	1,286	(913)	-71%
Deferred Standard Offer Revenue	21	13	8	57%
Current Portion of other liabilities	713	709	4	1%
Current Portion of long term debt	3,515	1,870	1,645	88%
	21,191	**24,966**	**(3,774)**	**-15%**
Regulatory Liabilities				
Retail Cost Variances	(393)	(318)	(76)	24%
Deferred Payment in Lieu of Taxes	0	(823)	823	-100%
Retail Settlement Variances	(535)	2,725	(3,260)	-120%
Low Voltage Variances	(134)	51	(185)	-362%
SmartGrid OMA Deferral (GEA)	(19)	(19)	0	0%
Smart Meters	(1,284)	(2,095)	811	-39%
Other Regulatory Assets	(28)	(23)	(4)	19%
Smart Metering Entity Variance	(33)	-37	4	-11%
Deferral Change in Accounting Policy Depreciation	5,853	3055	2,798	92%
Deferral & Variance Recovery 2010 IRM	0	117	(117)	-100%
Deferral & Variance Recovery 2011 COS application	0	110	(110)	-100%
Deferral & Variance Recovery 2012 application	41	543	(502)	-92%
Deferral & Variance Recovery 2014 application	1,189	0	1,189	100%
Deferral & Variance Recovery PILS application	0	823	(823)	-100%
	4,657	**4,107**	**549**	**13%**
Non-Current Liabilities				
Employee Sick Leave Liability	49	113	(64)	-57%
Employee Future Benefits	3,907	3,886	21	1%
Customer Deposits	713	747	(34)	-5%
	4,669	**4,746**	**(77)**	**-2%**
Long Term 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	33,725	27,240	6,485	24%
	59,330	**52,845**	**6,485**	**12%**
Shares				
Share Capital	31,246	31,246	0	0%
Contributed Surplus	25,459	25,459	(0)	0%
Retained Earnings	26,984	26,588	395	1%
	83,689	**83,294**	**395**	**0%**
TOTAL LIABILITIES & EQUITY	**173,536**	**169,957**	**3,578**	**2%**

Niagara Peninsula Energy
Projected Statement of Operations vs Budget
For the year ending December 31, 2014
(000's)

	Projected 2014	Budget 2014	Projected vs Budget $ Variance	Projected vs Budget % Variance	Actual 2013	Projected 2014 vs Actual 2013 $ Variance	Projected 2014 vs Actual 2013 % Variance
SERVICE REVENUE							
Standard Supply Service NF	114,306	114,458	(153)	0%	107,817	6,488	6%
Wholesale, Network & Connection Charges	23,451	22,779	672	3%	22,743	708	3%
Service Charge	15,770	12,778	2,992	23%	12,819	2,952	23%
Distribution Volumetric Charge	15,103	15,029	74	0%	15,091	12	0%
Standard Supply Service Admin Charge	144	141	3	2%	142	2	1%
Retailer Revenue	43	45	(3)	-6%	45	(2)	-5%
	168,817	165,231	3,586	2%	158,657	10,160	6%
Cost of Power							
Power Purchased	137,757	137,237	(519)	0%	130,560	(7,197)	-6%
Gross Profit Before Other Revenue	31,060	27,994	3,067	11%	28,097	2,964	11%
Other Revenue	1,842	1,513	329	22%	1,956	(114)	-6%
Less: Regulatory Debit	2,798	2,942	(143)	-5%	3,055	(256)	-8%
Gross Profit	30,104	26,565	3,539	13.32%	26,998	3,106	12%
Expenses							
Operation and maintenance							
Distribution	6,537	6,457	(80)	-1%	6,160	(378)	-6%
Utilization	192	184	(8)	-4%	203	11	5%
Administration & general	6,961	6,965	4	0%	6,555	(406)	-6%
Billing & Collecting	5,926	4,772	(1,154)	-24%	4,018	(1,908)	-47%
Depreciation	5,645	5,715	70	1%	5,321	(324)	-6%
Depreciation on FMV adjustment of fixed assets	1,099	1,100	1	100%	1,132	33	3%
TOTAL EXPENSES	26,361	25,193	(1,168)	-5%	23,389	(2,972)	-13%
Net Income before Extraordinary Item	3,743	1,372	2,371	173%	3,610	133	4%
Extraordinary Item							
Deferral & Variance (Refund)/Recovery PILS	633	508	(124)	100%	1,555	922	100%
Net Income After Extraordinary Item	3,111	864	2,495	289%	2,055	1,056	51%
Payments in Lieu of Income Taxes							
Income Tax expenses - current	1,516	707	(808)	-114%	86	(1,430)	-1664%
Income tax expense future reduction	0	0	-	#DIV/0!	511	511	100%
Total payments in lieu of income taxes	1,516	707	(808)	-114%	597	(919)	-154%
Net Income/(Loss) After Taxes	1,595	157	1,438	917%	1,458	137	9%

Statistics

	Projected 2014	Budget 2014	Projected vs Budget	Actual 2013	Projected 2014 vs Actual 2013
Cost of Power %	81.60%	83.06%	1.46 pts	82.29%	0.69 pts
Gross Profit % After Other Revenue	17.83%	16.08%	1.75 pts	17.02%	0.82 pts
Total Expenses as % of Total Revenue	15.61%	15.25%	(0.37) pts	14.74%	(0.87) pts
Net Income After Tax as % of Total Revenue	0.94%	0.09%	0.85 pts	0.92%	0.03 pts
Other Revenue	1.09%	0.92%	0.18 pts	1.23%	(0.14) pts
Distribution	3.87%	3.91%	0.04 pts	3.88%	0.01 pts
Utilization	0.11%	0.11%	(0.00) pts	0.13%	0.01 pts
Administration & general	4.12%	4.22%	0.09 pts	4.13%	0.01 pts
Billing & Collecting	3.51%	2.89%	(0.62) pts	2.53%	(0.98) pts
Depreciation	3.34%	3.46%	0.11 pts	3.35%	0.01 pts

Niagara Peninsula Energy Inc.
Statement of Cash Flows
For the year ending December 31, 2014

	Projected 2014 $	Actual 2013 $
Cash Provided By (Used In):		
Operations		
Net Income for the year	1,595	1,458
Items not involving cash		
Loss on Retirement of fixed assets		68
Depreciation	5,645	5,321
Depreciation expense on fair market value adjustment of fixed assets	1,099	1,132
Future payments in-lieu of taxes	0	511
Employee future benefits	21	108
Regulatory Debit	2,798	3,055
	11,159	11,653
Changes in non-cash working capital components	(2,348)	(4,634)
	8,811	7,018
Investments		
Due to affiliated companies	(0)	(583)
Additions to property and equipment-net	(14,286)	(12,649)
Regulatory costs	(2,305)	(2,108)
	(16,591)	(15,340)
Financing		
Long-Term Deposits	(34)	18
Employees' accumulated vested sick leave	(64)	(56)
Long Term Bank Loan	6,485	7,687
Dividend on Common Shares	(1,200)	(1,200)
	5,187	6,449
Increase (Decrease) in Cash Position	(2,592)	(1,873)
Cash Position, Beginning of Year	11,481	13,354
Cash Position, End of Year	8,889	11,481

Niagara Peninsula Energy Inc.
Statement of Retained Earnings
for the year ending December 31, 2014
(000's)

	Projected 2014	Actual 2013
Retained Earnings, Beginning of Year	26,588	26,330
Net Income	1,595	1,458
Dividends on common shares	(1,200)	(1,200)
Retained Earnings, End of Period	26,984	26,588

Niagara Peninsula Energy
Projected Capital Budget
For the year ending December 31, 2014
(000's)

	Projected 2014	Budget 2014	Projected vs Budget Variance	Actual 2013	Projected 2014 vs 2013 Variance
Land and Land Rights	0	0	0	1	(1)
Buildings & Fixtures	1,377	1,303	(74)	572	(805)
Sub Total	1,377	1,303	(74)	572	(806)
Distribution Station	505	252	(253)	501	(4)
Transformer Station	16	0	(16)	0	(16)
Overhead Distribution	4,363	3,836	(527)	4,786	423
Underground Distribution	3,515	3,782	267	2,476	(1,039)
Distribution Transformers	1,252	1,818	566	1,371	119
Meters	682	602	(80)	275	(407)
Capital Contributions	(1,049)	(900)	149	(991)	58
Sub Total before unusual contributions	9,284	9,390	106	8,418	(866)
Office Furniture & Equipment	158	157	(1)	170	12
Computer Equipment, Hardware	269	297	28	276	7
Computer Software	443	499	56	115	(328)
Vehicles < 3 tonnes	0	0	0	158	158
Vehicles > 3 tonnes	635	650	15	1,172	537
Vehicles transportation other	21	22	1	0	(21)
Vehicle Disposals	(441)	0	441	0	441
Stores Equipment	48	75	27	0	(48)
Tools, Shop & Garage Equipment	68	67	(1)	83	16
Measurement & Testing Equipment	0	0	0	0	0
Communication equipment	258	228	(30)	344	86
Miscellaneous equipment	0	0	0	0	0
Sub Total	1,459	1,995	536	2,318	859
Total Capital before non-recuring capital expenditures/(contributions)	**12,120**	**12,688**	**568**	**11,309**	**(814)**
Non-recuring Capital Expenditures					
Wire Building	0	0	0	980	980
High mast lighting	263	198	(65)	360	97
Total non-recuring capital expenditures	263	198	(65)	1,340	1,076
Net Capital Expenditures	12,383	12,886	503	12,649	263
Smart Meters Prior Years	1,903	0	(1,903)	0	(1,903)
Total capital expenditures	14,286	12,886	(1,400)	12,649	(1,640)

Niagara Peninsula Energy
Budget Balance Sheet
As at December 31, 2015
(000's)

	Budget 2015	Projected 2014	$ Variance	% Variance	Actual 2013	$ Variance	% Variance
ASSETS							
Current Assets							
Cash	6,314	8,889	(2,575)	-29.0%	11,481	(2,592)	-23%
Accounts Receivable	11,056	11,001	55	0.5%	10,538	463	4%
Unbilled Revenue	15,763	15,685	78	0.5%	16,626	(941)	-6%
Due from Affiliated Companies							
Peninsula West Services	2	2	0	0%	2	(0)	-5%
Payments in lieu of corporate taxes refundable	0	384	(384)	0%	1,521	(1,137)	-75%
Inventories	1,592	1,769	(177)	-10%	1,622	147	9%
Prepaid Expenses	875	871	4	0%	829	42	5%
	35,602	**38,600**	**(2,998)**	**-8%**	**42,619**	**(4,019)**	**-9%**
Fixed Assets							
Land and land rights	2,963	2,963	0	0%	2,963	0	0%
Buildings	17,209	16,989	220	1%	15,349	1,640	11%
Distribution Stations	9,373	9,373	0	0%	8,868	0	0%
Transformer Station	6,576	6,576	0	0%	6,560	0	0%
Distribution lines							
Overhead	100,950	96,416	4,533	5%	92,207	4,209	5%
Underground	87,291	83,986	3,304	4%	80,809	3,177	4%
Distribution transformers	41,104	39,846	1,258	3%	39,070	776	2%
Distribution meters	10,280	9,853	428	4%	7,593	2,260	30%
Trucks and Equipment	23,175	21,244	1,931	9%	19,541	1,703	9%
	298,920	287,246	11,674	4%	272,961	14,286	5%
Less: Accumulated Depreciation	(159,415)	(153,391)	(6,024)	4%	(146,703)	(6,688)	5%
	139,505	**133,855**	**5,650**	**4%**	**126,258**	**7,597**	**6%**
Future payments in lieu of taxes	**500**	**1,081**	**(581)**	**-54%**	**1,081**	**(0)**	**0%**
TOTAL ASSETS	**175,608**	**173,536**	**2,072**	**1%**	**169,957**	**3,579**	**2%**

Niagara Peninsula Energy
Budget Balance Sheet
As at December 31, 2015
(000's)

	Budget 2015	Projected 2014	$ Variance	% Variance	Actual 2013	$ Variance	% Variance
LIABILITIES							
Current Liabilities							
Accounts Payable	17,060	16,563	497	3%	13,981	2,582	18%
Due to Niagara Falls Hydro Services Inc.	0	0	(0)	-100%	6,913	(6,913)	-100%
Deferred Capital Contributions	0	6	(6)	-100%	192	(186)	100%
Deferred Standard Offer Revenue	21	21	0	0%	1,286	(1,265)	-98%
Deferred OPA revenues	1,500	373	1,127	302%	13	360	100%
Current Portion of other liabilities	727	713	14	2%	709	4	1%
Current Portion of long term debt	970	3,515	(2,545)	-72%	1,870	1,645	88%
	20,279	**21,191**	**(913)**	**-4%**	**24,966**	**(3,774)**	**-15%**
Regulatory Liabilities							
Retail Cost Variances	(147)	(393)	246	-63%	(318)	(76)	24%
Deferred Payment in Lieu of Taxes	0	0	0	0%	(823)	823	0%
Retail Settlement Variances	1,200	(535)	1,735	-324%	2,725	(3,260)	-120%
Low Voltage Variances	100	(134)	234	-175%	51	(185)	-362%
SmartGrid OMA Deferral (GEA)	0	(19)	19	-100%	(19)	0	0%
Smart Meters	(910)	(1,284)	375	-29%	(2,095)	811	-39%
Other Regulatory Assets	0	(28)	28	-100%	(23)	(4)	19%
Smart Metering Entity Variance	(33)	(33)	0	0%	(37)	4	100%
Deferral Change in Accounting Policy Depreciation	5,853	5,853	0	100%	3,055	2,798	100%
Deferral & Variance Recovery 2010 IRM	0	0	0	0%	117	(117)	-100%
Deferral & Variance Recovery 2011 COS application	0	0	0	0%	110	(110)	-100%
Deferral & Variance Recovery 2012 application	0	41	(41)	0%	543	(502)	-92%
Deferral & Variance Recovery 2014 application	100	1,189	(1,089)	-92%	0	1,189	100%
Deferral & Variance Recovery 2015 application	(207)	0	(207)	100%	0	0	100%
Deferral & Variance Recovery PILS application	0	0	0	0%	823	(823)	-100%
	5,956	**4,657**	**1,300**	**28%**	**4,107**	**549**	**13%**
Non-Current Liabilities							
Employee Sick Leave Liability	57	49	8	16%	113	(64)	-57%
Employee Future Benefits	3,957	3,907	50	1%	3,886	21	1%
Customer Deposits	727	713	14	2%	747	(34)	-5%
	4,742	**4,669**	**72**	**2%**	**4,746**	**(77)**	**-2%**
Long Term Liabilities							
Long Term Note Payable to City of Niagara Falls	22,000	22,000	0	0%	22,000	0	0%
Long Term Note Payable NF Hydro Holding	3,605	3,605	0	0%	3,605	0	0%
Long Term Bank Loan	32,754	33,725	(970)	-3%	27,240	6,485	24%
	58,359	**59,330**	**(970)**	**-2%**	**52,845**	**6,485**	**12%**
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	29,567	26,984	2,583	10%	26,588	395	1%
	86,272	**83,689**	**2,583**	**3%**	**83,294**	**395**	**0%**
TOTAL LIABILITIES & EQUITY	**175,608**	**173,536**	**2,072**	**1%**	**169,957**	**3,579**	**2%**

Niagara Peninsula Energy Inc.
Budgeted Statements of Operations
For the year ending December 31, 2015
(000's)

	Budget 2015	Projected 2014	2015 vs 2014 $ Variance	2015 vs 2014 % Variance	Actual 2013	2014 vs 2013 $ Variance	2014 vs 2013 % Variance
SERVICE REVENUE							
Standard Supply Service NF	113,866	114,306	(440)	-0.38%	107,817	6,488	6.02%
Wholesale, Network & Connection Charges	23,078	23,451	(374)	-1.59%	22,743	708	3.12%
Service Charge	14,996	15,770	(774)	-4.91%	12,819	2,952	23.03%
Distribution Volumetric Charge	14,323	15,103	(780)	-5.17%	15,091	12	0.08%
Standard Supply Service Admin Charge	141	144	(4)	-2.54%	142	2	1.48%
Retailer Revenue	45	43	3	6.54%	45	(2)	-5.31%
	166,448	168,817	(2,369)	-1.40%	158,657	10,160	6.40%
Cost of Power							
Power Purchased	136,943	137,757	814	0.59%	130,560	(7,197)	-5.51%
Gross Profit Before Other Revenue	29,505	31,060	(1,555)	-5.01%	28,097	2,964	10.55%
Other Revenue	1,443	1,842	(399)	-21.64%	1,956	(114)	-5.85%
Less: Regulatory Debit	0	2,798	(2,798)	-100.00%	3,055	(256)	-8.39%
Gross Profit	30,948	30,104	845	2.81%	26,998	3,106	11.50%
Expenses							
Operation and maintenance							
Distribution	6,747	6,537	(210)	-3.21%	6,160	(378)	-6.13%
Utilization	176	192	15	8.06%	203	11	5.37%
Administration & general	7,235	6,961	(274)	-3.93%	6,555	(406)	-6.20%
Billing & Collecting	5,610	5,926	316	5.33%	4,018	(1,908)	-47.48%
Depreciation Expense	4,937	5,645	708	12.55%	5,321	(324)	-6.09%
Depreciation on FMV adjustment of fixed assets	1,087	1,099	12	1.12%	1,132	33	2.93%
TOTAL EXPENSES	25,792	26,361	569	2.16%	23,389	(2,972)	-12.71%
Net Income before Extraordinary Item	5,157	3,743	1,413	37.75%	3,610	133	3.70%
Extraordinary Item							
Deferral & Variance Refund/Recovery PILS	0	633	633	100.00%	1,555	922	100.00%
Net Income After Extraordinary Item	5,157	3,111	2,046	65.76%	2,055	1,056	51.37%
Payments in Lieu of Income Taxes							
Income Tax expenses - current	1,374	1,516	(142)	-9%	86	(1,288)	-1498%
Income tax expense future reduction	0	0	0	0%	511	511	100%
Total payments in lieu of income taxes	1,374	1,516	(142)	-9%	597	(777)	-130%
Net Income/(Loss) After Taxes	3,783	1,595	2,188	137.15%	1,458	1,832	125.66%

Statistics					
Cost of Power %	82.27%	81.60%	(0.67) pts	82.29%	0.69 pts
Gross Profit % After Other Revenue	18.59%	17.83%	0.76 pts	17.02%	0.82 pts
Total Expenses as % of Total Revenue	15.50%	15.61%	0.12 pts	14.74%	(0.87) pts
Net Income After Tax as % of Total Revenue	2.27%	0.94%	1.33 pts	0.92%	1.35 pts
Income Tax % of Net Income	26.64%	40.49%	(13.85) pts	2.38%	24.26 pts
Other Revenue	0.87%	1.09%	(0.22) pts	1.23%	(0.37) pts
Distribution	4.05%	3.87%	(0.18) pts	3.88%	0.01 pts
Utilization	0.11%	0.11%	0.01 pts	0.13%	0.01 pts
Administration & general	4.35%	4.12%	(0.22) pts	4.13%	0.01 pts
Billing & Collecting	3.37%	3.51%	0.14 pts	2.53%	(0.98) pts
Depreciation	2.97%	3.34%	0.38 pts	3.35%	0.01 pts

Niagara Peninsula Energy Inc.
Statement of Cash Flows
For the year ending December 31, 2015

	Budget 2015 $	Projected 2014 $
Cash Provided By (Used In):		
Operations		
Net Income for the year	3,783	1,595
Items not involving cash		
Loss on Retirement of fixed assets		
Depreciation	4,937	5,645
Depreciation expense on fair market value adjustment of fixed assets	1,087	1,099
Future payments in-lieu of taxes	581	0
Employee future benefits	50	21
Regulatory Debit	0	2,798
	10,438	11,159
Changes in non-cash working capital components	(490)	(2,348)
	9,948	8,811
Investments		
Due to affiliated companies	0	(0)
Additions to property and equipment-net	(11,674)	(14,286)
Regulatory costs	1,300	(2,305)
	(10,374)	(16,591)
Financing		
Long-Term Deposits	14	(34)
Employees' accumulated vested sick leave	8	(64)
Long Term Bank Loan	(970)	6,485
Dividend on Common Shares	(1,200)	(1,200)
	(2,148)	5,187
Increase (Decrease) in Cash Position	(2,575)	(2,592)
Cash Position, Beginning of Year	8,889	11,481
Cash Position, End of Year	6,314	8,889

Niagara Peninsula Energy Inc.
Statement of Retained Earnings
for the year ending December 31, 2015
(000's)

	Budget 2015	Projected 2014
Retained Earnings, Beginning of Year	26,984	26,588
Net Income	3,783	1,595
Dividends on common shares	(1,200)	(1,200)
Retained Earnings, End of Period	29,567	26,984

Niagara Peninsula Energy Inc.
Capital Budget 2015
For the year ending December 31, 2015
(000's)

	Appendix	Budget 2015	Projected 2014	Budget 2015 vs Projected 2014 Variance	Budget 2014	Projected 2014 vs Budget 2014 Variance	Original Budget 2013	Actual 2013
Land and Land Rights	A		0	0	0	0	25	1
Buildings & Fixtures	A	220	1,377	74	1,303	(74)	1,865	572
Sub Total		220	1,377	74	1,303	(74)	1,890	573
Distribution Station	B	0	505	253	252	(253)	557	501
Transformer Station	B	0	16	16	0	(16)	30	0
Overhead Distribution	B	4,533	4,363	527	3,836	(527)	4,163	4,786
Underground Distribution	B	3,842	3,515	(267)	3,782	267	2,870	2,476
Distribution Transformers	B	1,547	1,252	(566)	1,818	566	1,593	1,371
Meters	B	428	682	80	602	(80)	400	275
Capital Contributions	B	(828)	(1,049)	(149)	(900)	149	(845)	(991)
Sub Total before unusual contributions		9,523	9,284	(106)	9,390	106	8,768	8,418
Office Furniture & Equipment	C	69	158	1	157	(1)	185	170
Computer Equipment, Hardware	D	235	269	(28)	297	28	593	276
Computer Software	E	488	443	(56)	499	56	283	115
Vehicles < 3 tonnes	F	285	0	-	0	0	200	158
Vehicles > 3 tonnes	F	343	635	(15)	650	15	1,195	1,172
Vehicle Disposals		0	(441)	(441)	0	441	0	0
Vehicles Transportation Other	F	225	21	(1)	22	1	0	0
Stores Equipment	F	0	48	(27)	75	27	25	0
Tools, Shop & Garage Equipment	G	68	68	1	67	(1)	88	83
Measurement & Testing Equipment		1	0	0	0	0	0	0
Communication equipment	H	215	258	30	228	(30)	200	344
Miscellaneous equipment		1	0	0	0	0	0	0
Sub Total		1,931	1,459	(536)	1,995	536	2,769	2,318
Total Capital before non-recuring capital expenditures/(contributions)		**11,674**	**12,120**	**(568)**	**12,688**	**568**	**13,427**	**11,309**
Wire Building		0	0	0	0	0	1,020	980
High mast lighting		0	263	65	198	(65)	550	360
		0	263	65	198	(65)	1,570	1,340
Net Capital Expenditures		**11,674**	**12,383**	**(503)**	**12,886**	**503**	**14,997**	**12,649**
Smart meter purchases from prior years		0	1,903	1,903	0	(1,903)	0	0
		11,674	**14,286**	**1,400**	**12,886**	**(1,400)**	**14,997**	**12,649**

APPENDIX A

Building 2015

	2015 Budget
Building	
Paving new surface area	220,000
Total	**220,000**

APPENDIX B

Project	Gross Capital Investment	Capital Contribution	Net Capital Investment
Crawford St. Area Carry	282,324	-	282,324
Beck Road	144,237	-	144,237
Willodell Rebuild	310,710	-	310,710
Willoughby Drive	372,191	-	372,191
Willoughby Dr Extension	383,293	-	383,293
Switchgear	250,002	-	250,002
Rolling_Acres	570,500	-	570,500
NWTC Metering	289,605	-	289,605
Sectionalizing	73,000	-	73,000
Frederica	676,144	-	676,144
NPC	818,905	-	818,905
Reclosers	100,000	-	100,000
PCB TX Changeouts	495,104	-	495,104
Jordan Ph 2	449,324	52,800	396,524
King St. 27.6kV Ext at Martin	114,460	-	114,460
Lightning Mit.	30,000	-	30,000
Road Relocation	500,000	125,000	375,000
Pole Changeouts	431,729	-	431,729
Station 22 Loads S of Pew Carry	143,724	-	143,724
Station 22 Loads N of Pew	507,139	-	507,139
Kiosks	647,029	-	647,029
Sustainment	680,000	-	680,000
Subdiv Lots	275,000	200,000	75,000
Subdiv Conn	312,004	-	312,004
Lot Rebates	150,000	-	150,000
Demand	1,007,500	450,000	557,500
Metering	193,500	-	193,500
MIST meters	143,150	-	143,150
Totals	10,350,575	827,800	9,522,775

PROPOSED N.P.E.I 2015 CAPITAL BUDGET PROGRAM

As in previous years, the NPEI 2015 Capital Budget will continue 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 cyclic programs include Rebuild/Reinforcement/ Conversion Construction, Pole Testing & Inspections, Pad-mounted Equipment Inspections, Sub-station Testing & Inspections, Manhole & Sidewalk Vault Inspections, Kiosk Inspections, Minor System Betterments, Subdivision Connections, and Demand Based System Expansions for Commercial Development.

1. **Expansions and Reinforcement of the N.P.E.I. 13.8 K.V. / 27.6 K.V. Primary Distribution System to accommodate load growth & reliability requirements.**

- **Crawford Street--Thorold Stone South to Sheldon Carry-over**

Completion of the Rebuild Project which targets 1.38 kilometers of urban distribution line installed in 1953, including 50 pole changes, new single (880M) & three phase (500M) primary and secondary (1790M) circuits, 10 distribution transformer replacements resulting in the upgraded supply to about 122 residential customers directly, in an area bounded by Drummond Rd., Portage Rd, Sheldon St., St James St., Longhurst Ave, Elberta Ave. & Crawford St. System benefits include replacement of aging equipment, future voltage conversions opportunities, improved equipment clearance, and increased Customer reliability.
Estimated cost: $ 282,323.71 ***-- NF Service Area Project #2015-0001***

- **Beck Road--Marshall to Schisler Road**

Project scope involves replacement/relocation of 0.7 KM. of a rural overhead 2.4 KV (RECL-2) off-road primary distribution line, with an overhead 15 KV class single phase line relocated within the Beck Rd allowance between Marshall Rd & Schisler Rd. Installation of 16-new 45' wood poles, 1-25KVA transformer and transfer 5 existing services. System benefits include the replacement of aging equipment originally installed in 1955, constructed on private property, by Ontario Hydro, without registered easements in favor of the Utility, relocation of inaccessible infrastructure, future capability of conversion to 15KV with clearance sufficient to construct 3-phase if required, improved reliability and reduced response time due to improved equipment access.
Estimated Cost= $ 144,237.09 ***-- NF Service Area Project #2015-0002***

- **Willodell Road--Gonder to Koabel Road**

Project scope involves replacement/relocation of 1.5 KM. of rural overhead 2.4 KV (RECL-2) off-road primary line with an overhead 15 KV class single phase line relocated within the Willodell Road Allowance between Gonder Rd & Koabel Rd. Installation of 27-new 45' wood poles, 6-25KVA transformer and transfer 8-existing services. System benefits include the replacement of aging equipment originally installed in 1949, constructed on private property, by Ontario Hydro, without registered easements in favor of the Utility, relocation of inaccessible infrastructure, future capability of conversion to 15KV with clearance sufficient to construct 3-phase if required, improved reliability and reduced response time due to improved equipment access.
Estimated Cost= $ 310,710.49 ***-- NF Service Area Project #2015-0003***

- **Willoughby Drive--Main Street to Cattell Drive**

Project scope involves the replacement of 1.2 KM. of urban overhead 13.8 KV primary line installed in 1960 with 17-new 45’ wood poles framed for 3-phase, 10-new 40' wood poles framed for single phase and re-conductor the existing 3/0 Lum with 556 MCM 3-phase main circuit, constructed in the same alignment as the existing pole line, install 7-single phase & 1-three phase transformer to replace existing, install 1.1KM of secondary buss, and transfer of 34 services to the new buss. Benefits include improved system losses, improved equipment clearances, reinforcement & capacity increase of the main distribution line.

Estimated Cost= $ 372,190.81 ***--NF Service Area—Project #2014-0004***

- **Willoughby Drive-- Cattell Drive to Weinbrenner Road**

Project scope involves the replacement of 0.7 KM. of urban overhead 13.8 KV primary line installed in 1969 with 21-new 45' wood poles framed for 3-phase & 4-new 40' wood poles framed for single phase and re-conductor the existing 3/0 Lum with 556 MCM 3-phase main circuit, constructed in the same alignment as the existing pole line, install 5-single phase & 1-three phase transformer to replace existing, install 1.1KM of secondary buss, and transfer of 30 services to the new buss. Benefits include improved system losses, improved equipment clearances, reinforcement of supply to a sensitive load (large Senior Care Facility) .

Estimated Cost= $ 383,293.15 ***--NF Service Area—Project #2014-0005***

- **Pad-mounted Switchgear Replacements**

The Underground Equipment Inspection Program has identified a requirement for replacement of pad-mounted switchgear units due to corrosion and contamination issues, which will continue at a rate of 3-Units per year. 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= $ 250,000.00 ***-- NF Service Area Project #2015-0006***

- **Overhead to Underground Primary Conversion-Rolling Acres Subdivision Phase II**

Phase II project scope involves the relocation of primary facilities located on an inaccessible rear lot pole line within private property, for which easement documentation is available. 1.0KM of Primary duct by directional boring technology to 5 pad-mounted transformers placed on precast pads within the Road Allowance. Secondary laterals will be directionally bored back to the rear lot easements, to source the 55 individual underground house services currently fed from junction boxes mounted on the distribution poles. The streets included within this Phase include Oxford, McColl Drive, Cambridge Street, Rolling Acres Drive. The current equipment was installed in 1961 and tree growth, pool, shed and fencing installations, have made the line difficult to maintain and service. There have been many issues in this subdivision during Ice/Wind Storms. 15KV rated equipment will be installed for future voltage conversion, once all the phases have been completed.

Estimated Cost = $ 570,500.09 ***- - NF Service Area —Project #2015-0008***

- **NWTS Metering Replacement**

Due to several failures of the existing 230 KV primary metering units monitoring the DESN at the Niagara West Transformer Station, NPEI has identified a need for the replacement of the 2 Primary Metering units with 4-low voltage feeder metering units, minimizing system wide outages which occurred during the metering failures, providing improved reliability and accuracy of billing and settlement.

Estimated Cost= $ 289,604.56 ***-- PW Service Area Project #2015-0009***

- **Additional Sectionalizing Switches—8-Units**

A review of existing feeder configurations, sourced by Stanley, Murray, Beamsville & Niagara West Transformer Stations , Kalar M.T.S. and Vineland D.S., utilizing system optimization software, has identified a need for additional pole mounted ganged load break switches within the system,

minimizing system losses, providing improved contingency options during outage events, providing a means to minimize the area affected. The program will target the installation of 8 additional units.
Estimated Cost= $ 73,000.00 ***-- Combined Service Area Project #2015-0010***

- **Frederica Street--Dorchester to Drummond Road**

Project scope involves the replacement of 1.1 KM. of existing 2/0 overhead 4.16 KV (F-104) primary line installed in 1955 with 16-new 45' wood poles & utilizing 12-existing poles replaced previously and re-conductor the existing with 556 MCM 3-phase main circuit, constructed in the same alignment as the existing pole line, install 4-new transformers, install 1.1KM of secondary buss, and transfer of 55 services to the new buss. Benefits include the final stage of reconstruction to eliminate Municipal Sub-station Stn. #22 constructed in 1969, targeted for decommissioning, the provision for immediate voltage conversion opportunities of several existing lateral feeds, improved system losses, improved equipment clearances.
Estimated Cost= $ 676,144.06 ***--NF Service Area—Project #2015-0011***

- **Niagara Parks Commission Primary Network**

The Niagara Parks Commission is a Provincial Entity located within the City of Niagara Falls which oversees all Operations associated with the Tourist Attractions under their jurisdiction. This also includes a significant Electrical Distribution System within it's boundaries. Negotiations are currently underway, initiated by the Customer, for NPEI to assume the primary distribution system up to the low voltage bushings of the transformers. The NPC does not have Staff qualified to operate and maintain the high voltage system, and would like to expand upon an Operating Agreement currently executed between both parties, where NPEI would own, maintain, and operate the high voltage system on their behalf. From the Customers due-diligence standpoint, and NPEI's capability to respond to the Customers emergency and growth requirements, with appropriate Staff, Equipment, and Material Stock, a mutually beneficial system expansion would result, increasing Public Safety and reliability.
Estimated Cost= $ 818,904.74 ***--NF Service Area—Project #2015-0012***

- **1-Phase Hydraulic Reclosure Upgrades—10-Units**

Approaching end of life cycles, and relating to the 5-year Wi-Max deployment plan, a requirement has been identified, for the replacement of 10-existing pole mounted hydraulic reclosures. There are approximately 90 oil filled units in service on the system. New units are solid dielectric, electronically controlled equipment, with interrogation/communication capabilities, providing Control Operators with real-time status during outage events, enabling restoration options. The solid dielectric insulation eliminates the oil used in the older units, making them less of an environmental concern.
Estimated Cost= $ 100,000.00 ***-- PW Service Area Project #2015-0013***

- **Replacement of Transformers with >50PPM PCB Content.**

The third and final phase of the three year transformer testing program has been completed in 2014 within the West Service Territory resulting in the requirement to replace approximately 50 units identified as having over the Legislated limit of PCB content. The program will track these change-outs which will likely include the replacement of the pole supporting the unit with associated transfers, removals and disposal costs. Benefits include meeting the requirement of the Legislation, and removal of the hazardous material from the system.
Estimated Costs: $ 495,104.13 ***--PW Service Area --Project #2015-0014***

- **Jordan Road—Red Maple to the QEW**

The Project Scope involves the rebuild of existing 3-phase 8320Volt primary line, in place, constructed to 27.6KV standards for approx 2.0 KM involving the installation of 34-new 45' Bell

Telephone Owned poles, transfer of existing primary conductors, and installation of 2.0km of new neutral. The project was driven by the pole inspection program which has identified a high number of deteriorated cross arms supporting the primary conductors. Benefits include elimination of the identified hazard, improved equipment clearance, and provisions for future conversion to 27.6KV of the feeders supplied by Jordan M.S. for its eventual de-commissioning.

Estimated Cost = $ 449,324.38(recoverable $52,800)-- PW Service Area Project #2015-0015

- **King Street—27.6 K.V. Extension to Martin Rd.**

The Project Scope involves the rebuild of existing 1-phase 16KV primary line west of Martin Ave to the 3-phase dead-end, in place, and constructed to 3-phase 27.6KV for approx 280 M. Construction involves the installation of 8-new 45' poles, transfer of 1-primary riser, and installation of 165 m of new 3-phase from Rittenhouse Road to Martin Rd, and removal of 6-existing poles. Benefits include improved supply reliability and flexibility on the system during contingencies & system configuration.

Estimated Cost = $ 114,449.97 -- PW Service Area Project #2015-0018

- **Lightning Mitigation Measures-**

The continuation of an established sustainment Program, the project scope involves the installation of additional lightning mitigation equipment throughout the distribution system within the Western Service Territory to correct deficiencies identified through recent storm related equipment failure events. Benefits include improved reliability indices, reduction in the amount of equipment damaged during storm events, improved outage restoration times.

Estimated Cost = $ 30,000.00 - -PW Service Area —Project #2015-0019

2. 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: $500,000.00 (recoverable $125,000) -- Combined Service Area

3. **Replacement of Poles identified with limited Structural Integrity.**

The natural degradation of wooden utility poles is an ongoing issue. Per the Distribution System Code, 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. In the Niagara Area pole replacements are beginning to level off as cycles begin to repeat, with a structured treatment program implemented during the testing cycle to increase the poles life cycle. The 2015 Niagara test area is bounded in the West by the City Limits/Thorold Town Line Rd., South to the Welland River, and East to Stanley Ave, North to Hwy #420/Beaverdams Road and includes 3693 poles total. The Western Service Territory test area is bounded by Mud Street to the north, south to Twenty Road, east to Walker Road, and west to South Grimsby Road 20 and includes 3157 poles. The average cost per pole change is approximately $ 5,000.

Estimated Costs: $ 431,729.48 --Combined Service Area --Project #2015-1010/2010

4. **Overhead line rebuilds of facilities identified by the Pole Inspection Survey.**

This Capital Program targets overhead distribution facilities identified at end of life, determined from results of the Pole Testing Program. Existing overhead distribution equipment at these locations, are replaced with new overhead facilities incorporating new poles, conductors and transformers to maximize efficiency, reliability and the ability for conversion to a higher distribution voltage as warranted. For 2015 this program targets the 2-areas listed below with the first being a carry-over from 2014 and the latter being the second phase for the elimination of Municipal Sub-Station #22.

- **Station #22--Voltage Conversion Carry-over Phase I**

Completion of the Rebuild Project which targets 1.70 kilometers of urban distribution line installed in 1953, including 58 pole changes, new single (1.70KM) and secondary (1.70KM) circuits, 10 distribution transformer replacements resulting in the upgraded supply to about 125 residential customers directly, in the area bounded by Dorchester Rd., Lundy's Lane, Brookfield Ave, & Coach Dr. System benefits include reconstruction to eliminate Municipal Sub-station Stn. #22 constructed in 1969, targeted for decommissioning, replacement of aging equipment, future voltage conversions opportunities, improved equipment clearance, and increased Customer reliability.

Estimated cost: $ 143,724.04 ***-- NF Service Area Project #2015-0007***

- **Station #22--Voltage Conversion Phase II**

Rebuild Project which targets 1.20 kilometers of urban distribution line installed in 1953, including 38 pole changes, new single-phase (1.2KM) & secondary (1.4KM) circuits, 8 distribution transformer replacements resulting in the upgraded supply to about 119 residential customers directly, in the area bounded by Dorchester Rd., Lundy's Lane, Brookfield Ave., & Garden St. System benefits include reconstruction to eliminate Municipal Sub-station Stn. #22 constructed in 1969, targeted for decommissioning, replacement of aging equipment, immediate voltage conversions opportunities, improved equipment clearance, and increased Customer reliability.

Estimated cost: $ 507,139.32 ***-- NF Service Area Project #2015-0007***

5. **Replacement of Kiosks containing Transformers, EFD Switches, and Posi-tects.**

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 2013.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. 57-Units remain on the 15KV System, and 74-Units remain on the 5KV System. For 2015 the plan is to replace 10 to 15 units.

Estimated cost: $647,028.76 ***-- Combined Service Area Project #2015-0020***

6. **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: $ 680,000 ***-- Combined Service Area-- Project #2015-1007/2007***

7. Subdivisions and new residential services

Estimated cost:	***Lot servicing of existing***	***$275,000***
	Recoverable	***($200,000)***
		$ 75,000
	Connection and energizing of new subs	***$312,004***
	Lot connection rebates	***$150,000***

8. 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: $1,007,500.00 ***–Combined Area-- Project #2015-1008/2008***
(recoverable $450,000)

9. Other Capital Expenditures as listed below:

Metering	*$193,500*
MIST meters	*$143,150*

Project Total	***$10,350,575***
Recoverable	***($ 827,800)***
TOTAL	***$_9,522,775***

APPENDIX C

General Equipment

	2015 Budget
Ergonomic Office Equipment	8,670
Photocopier	21,000
Control Room workstation & working table	10,000
Meeting Room in existing lead hand area	6,000
2 additional offices	12,000
General Equipment as needed	11,000
	68,670

APPENDIX D

Hardware

Category	Item	Purpose	2015 Budget
Network	48 Port Nortel Switch	Redundancy	6,000
Network	24 Port Nortel Switch	Redundancy	6,000
Network	24 Port Nortel Switch	Redundancy	6,000
Network	48 Port Nortel Switch	Redundancy	6,000
Network	Replace Bluecoat ProxyAV	End of Life	6,000
Servers	Tape Library or Disk to Disk 2 Tape Backup Solution	Improved backup system from using tape	10,000
Servers	Server	Outage Management System	10,000
Servers	Server	Informix to SQL	20,000
Servers	Server	Intranet, web based applications	20,000
Printers	HP9050 Printer for Billing Department		6,000
Printers	Lexmark		500
Phones	Professional Services	Integration of phone system to CIS/Outage Management/IVR	25,000
PC / Monitor	PC's and Monitors	Add PCs as required	10,000
PC / Monitor	Field Durable Laptops	Deployment of field use in Operations, and mcare in Metering	42,000
PC / Monitor	Laptops/replacement tablets (for example Surface)	Brian, Marg, Suzanne, SueF, HR, Paul,CDM/Engineering	12,600
LCD Projectors	NEC VT595 XGA 2000 ANSI LUNCENS PROJECTORS	Niagara Falls and Smithville LCD Projectors (not mounted)	1,000
Equipment	Radix Handhelds	Meter reading	3,250
Barcoding Equipment	Barcode server in NF & DR Server for Barcode		20,000
Barcoding Equipment	5 Barcode handhelds		5,000
Servers	2 SCADA servers		20,000
			235,350

APPENDIX E

Software

Category	Item	2015 Budget
G&A&Ops	Accellos bar code software	50,000
G&A&Ops	Bar code customization	50,000
Billing	Upgrade to 6.x	50,000
Operations	Work Management/Outage Management Intergraph solution including software and professional services for installation and training	35,000
Operations & Engineering	Oracle Licenses - Outage Management System	20,000
Operations	Visio Licenses	1,000
Operations	Mobile GO Payment Application	25,000
Billing	Harris Northstar Professional Services	25,000
Billing	Appollo WE Professional Services	25,000
Professional Services	Dell Professional Services for SAN (upgrade to SQL)	3,000
Professional Services	Layer 227 Support Services	2,000
Professional Services	Forsythe Services	2,000
Professional Services		60,000
Engineering	SCADA system	140,000
		488,000

APPENDIX F
Vehicles and Transportation Other Equipment 2015

Description	2015 Budget
Vehicles > 3 tonnes	
40' Aerial Squirt Boom Manlift. Replaces NF45, 2007 International aerial manlift	343,400
Total	343,400

Vehicles < 3 tonnes	**2015 Budget**
4X4 Crew Cab with 6' box and cap-on-call vehicle for Smithville. Replaces SV21 or SV22	45,000
4X4 Crew cab with 6' box for Operations Supervisors	120,000
4X4 Crew cab with 6' box for Engineering. Replaces SV17, SV19, NF22	120,000
	285,000

Transportation Equipment	**2015 Budget**
500 kVa portable generator	175,000
Smithville garage hoist	50,000
	225,000

APPENDIX G

Tools Budget 2015

Tools and Equipment for Vehicles	2015 Budget
6 Tonne battery press	4,500
Trac Mats -	1,500
Y35 Hydraulic Press	4,300
Fibre insulation cover up	4,000
Standard cable feeder 4X90 funnel	400
Electrical powered capstan for backyard transformer replacement	3,000
Impulse phaser for secondary identification	480
Various tension stringing accessories (rope& stringing blocks)	4,000
Gas monitors	1,800
Traffic signs and stands	3,120
Various replacement tools for budgeted new trucks	10,000
Miscellaneous Replacement Tools	19,240
	56,340

Tools for Garage	
Spark safe ergononmic mating	5,600
Install a fire rated man door and frame from the garage area to the lineman's storage area	4,400
Various other shop tools	2,000
Total cost of equipment purchase for 2015	12,000
Total Tool Budget	68,340

APPENDIX H

Communication Equipment

	2015 Budget
Wi-max pilot project communication expansion	215,000
Total	**215,000**

Niagara Peninsula Energy Inc.
Capital Budget 2010 - 2019
(000's)

	Actual 2010	Actual 2011	Actual 2012	Actual 2013	Projected 2014	Budget 2015	Prospective Plan 2016	Prospective Plan 2017	Prospective Plan 2018	Prospective Plan 2019
Land and Land Rights	0	0	5	1	0	0	0	0	0	0
Buildings & Fixtures	67	122	626	572	1,377	220	0	0	0	0
Sub Total	67	122	631	572	1,377	220	0	0	0	0
Distribution Station	509	800	684	501	505	0	0	439	0	0
Transformer Station	11	0	0	0	16	0	0	400	0	0
Overhead Distribution	3,884	3,912	3,663	4,786	4,363	4,533	4,624	5,321	5,792	6,310
Underground Distribution	3,068	2,783	3,148	2,476	3,515	3,842	4,296	2,775	2,779	2,448
Distribution Transformers	922	1,064	1,247	1,371	1,252	1,547	1,353	1,325	1,533	1,560
Meters	148	177	171	275	682	428	424	424	424	424
Capital Contributions	(625)	(1,664)	(1,585)	(991)	(1,049)	(828)	(775)	(775)	(775)	(775)
Sub Total before unusual contributions	7,917	7,072	7,328	8,418	9,284	9,523	9,921	9,909	9,753	9,967
Office Furniture & Equipment	35	69	112	170	158	69	20	20	20	35
Computer Equipment, Hardware	258	250	371	276	269	235	243	246	241	236
Computer Software	250	194	213	115	443	488	357	265	281	453
Vehicles < 3 tonnes	44	350	104	158	0	71	168	111	142	77
Vehicles > 3 tonnes	825	189	1,057	1,172	635	607	434	637	442	450
Vehicle Other	0	0	0	0	21	175	157	0	22	0
Vehicle Disposals	0	0	0	0	(441)	0	0	0	0	0
Stores Equipment	26	10	0	0	48	0	0	0	0	0
Tools, Shop & Garage Equipment	95	78	133	83	68	68	53	71	55	56
Measurement & Testing Equipment	6	15	0	0	0	1	1	1	1	1
Communication equipment	10	1	332	344	258	215	250	250	250	250
Miscellaneous equipment	5	0	0	0	0	1	1	1	1	1
Sub Total	1,554	1,156	2,322	2,318	1,459	1,931	1,684	1,602	1,454	1,561
Total Capital before non-recuring capital expenditures/(contributions)	**9,538**	**8,350**	**10,280**	**11,308**	**12,120**	**11,674**	**11,605**	**11,511**	**11,207**	**11,528**
Non-recuring Capital Expenditures										
Town of Pelham	(250)	0	0	0	0	0	0	0	0	0
RiverRealty Development	(210)	0	0	0	0	0	0	0	0	0
Fruitbelt Development	0	0	0	0	0	0	0	0	0	0
City of NF Oakwood Drive	(73)	0	0	0	0	0	0	0	0	0
Wesley Gardens Extension	0	0	0	0	0	0	0	0	0	0
Wire Building & High Mass Lighting	0	0	0	1,341	263	0	0	0	0	0
	(533)	0	0	1,341	263	0	0	0	0	0
Net Capital Expenditures	**9,005**	**8,350**	**10,280**	**12,649**	**12,383**	**11,674**	**11,605**	**11,511**	**11,207**	**11,528**

Average Net Capital Expenditures excluding non-recurring- 5 year	**10,319**	10 Year Averag	**10,912**
Average Net Capital Expenditures including non-recuring 5 year	**10,533**	10 Year Averag	**11,019**
Average Fixed Asset additions COS rate Application 2011 net of average $850K capital contributions	**9,345**		**9,345**

Appendix 1-8

NPEI's 2020 and 2016 Strategic Plans

niagara
peninsula
energy inc.
Your Local Utility

Niagara Peninsula Energy Inc.
Strategic Plan
2020

Niagara Peninsula Energy Strategic Plan 2020

Mission: To deliver safe, efficient, and reliable electricity with excellent customer service and community value, provided by engaged employees.

Vision: To be recognized as exceptional in delivering services and value, to our customers and communities.

Values: To conduct ourselves with commitment to the values of:

- Integrity- We are ethical and our actions are truthful and trustworthy;
- Fairness- We treat everyone equally and free of bias;
- Responsibility- We provide services with safety first for our customers and employees;
- Respect- We listen to each other, see the value that each member of the team brings, and respect the needs of our stakeholders, and
- Transparency- We are open and accountable for our actions and decisions

Executive Summary

There are six primary areas of NPEI's business that can be considered as key strategy categories: Customers, Operational, Public Policy, People, Financial and Information Technology.

For each of these; objectives, goals, measures of success, targets and actions were developed.

The strategic plan should be revisited regularly to ensure NPEI is striving to achieve its mission, vision and values. Customer engagement, performance based outcomes and cost/benefit analyses are an integral part of decision making and allocation of NPEI's resources. NPEI's cost of service rate application, distribution system plan and customer engagement plan will guide the use of resources over the next rebasing period.

NPEI's objectives and goals for each of the areas of its strategic plan are summarized below.

NPEI will understand and deliver on customer expectations for reliable, high quality, cost-effective service by enhancing customer satisfaction and customer engagement.

NPEI will productively manage assets and resources to meet current and future customer needs by expanding the transformation and distribution systems to meet electrical needs of current and future customers. NPEI will effectively maintain and refurbish aging plant facilities and equipment, provide high level of service quality, enhance system performance and reliability while ensuring 100% level of compliance with the Ontario Regulation 22/04 and promote public safety awareness.

NPEI will successfully deliver public policies, be environmentally responsible and respond to the needs of our communities. Smart Grid initiatives to improve reliability will be implemented to accommodate embedded generation. NPEI will be environmentally responsible, continuously engage in its communications and continue to develop its corporate image.

NPEI will invest in a safe, healthy and engaging workplace that attracts, retains and develops employees who contribute their best. Health and safety awareness will be promoted for NPEI employees and its "Safety Culture" will be strengthened. NPEI will gain a mutual understanding of its employees' job expectations; provide the equipment, resources and training to do the job well. Feedback and recognition of employee and team performance will be provided on a timely and ongoing basis. Employees will be provided with development opportunities, integrated with a corporate succession plan to sustain operations.

NPEI will deliver sustainable shareholder value and meet or exceed regulatory expectations. Long-term financial viability will be maintained and NPEI's balanced scorecard will be met or exceeded. NPEI will maintain regulatory compliance and meet or exceed the Ontario Energy Board's (OEB) scorecard expectations. Shareholder value will continuously be enhanced and dividend expectations will be met.

NPEI will continually improve with a focus on innovation and technology in all areas of the business and provide integrated solutions to meet customer and business needs.

Strengths

- Highly effective, well trained professional work force
- Imbedded Safety Culture (many years)
- Financial performance in upper tier of LDC in Ontario
- Strong Financial Resources as evidenced by Financial Statements
- Shareholders represent diverse communities
- Highly regarded presence in community
- Strong brand presence (Power of local hydro)
- Well built and well maintained electrical distribution system
- Extensive geographic “footprint”, which provides for customer growth
- Board of Directors is engaged and practices exceptional governance
- Regulated Industry→ Guaranteed rate of return and cost recovery (storm damage)
- Member of GridSmartCity Partnership

Weaknesses

- Size → Scale may be diminished in an increasing climate of LDC consolidation
- Consolidation forced by Municipal Governance reorganization
- Regulatory environment becomes subjected to changes in legislation or government directives.
- Shareholders need funds, which results in decrease to capital budgeting
- Environmental damages due to adverse weather conditions (i.e. severe wind storms, ice, water or flooding)
- Board of Director turnover
- Succession Plan → Sudden unexpected departures

Opportunities

- Service delivery → hosting of LDC's Information Technology requirements
- Growth through consolidation with culturally similar LDC's
- Assist Holding Corporations with review of other energy market opportunities (i.e. generation)
- 2020 Cost of Service Rate Application → opportunity to achieve organizational improvements and secure capital funding.

Threats

- Forced Amalgamation or Merger (M&A)
- Key staff departures (unexpected turnover)
- Regulatory uncertainty at OEB (under direction for Government)
- 2020 Cost of Service Rate Application (uncertainty and possible economic difficulty)
- Possible adverse economic conditions resulting in recession (decline in housing growth and economic activity).
- High Board of Director turnover resulting in a lack of continuity in governance.
- Significant adverse weather which may cause extension service disruption and material repair costs which the Ontario Energy Board does not allow for rate based recovery.

Environmental Scan

The LDC sector continues to evolve. The review of the strategic plan provides an opportunity for the Board of Directors and Senior Management to assess and evaluate their strengths, weaknesses, opportunities and threats.

This thought provoking process should be taken from an outward and inward looking perspective.

Recent political changes in Ontario have resulted in a significant change in political culture and tactics. The PC Government has focused its agenda on "For the People". This "cutting of waste" and "affordability" represents important themes and may result in significant legislative commitments. Potential restructuring of municipal government may result in "forced" mergers or divestiture. This could have significant impacts on NPEI. Furthermore, a campaign promise of 12% reduction in hydro rates poses risks to LDC's in the form of Rate of Return reductions, reductions in allowed expenditures and significant cost recovery thereby inhibiting service and reliability. This compounded with the expiration in 2021 of the Fair Hydro Plan may result in changes to Energy Policy.

The provincial government promotes and desires more privatization and consolidation in the LDC sector. This as well as the Municipal Governance review poses potentially significant changes to the Niagara Peninsula Energy ownership model. A proactive and aggressive approach may be required to deal with any imposed changes to our structure.

The Electrical Distributors Association "Power of Local Hydro" campaign and our involvement with the GridSmartCity Co-operative provide a successful model to leverage our strength going forward.

The provincial government has recently initiated a comprehensive review of the Ontario Energy Board. It can be expected that this review will provide guidance and direction on a number of very important activities which may impact Niagara Peninsula Energy and our upcoming 2021 Rate Application.

These may be considered to be:

- Distributed Energy Resource connections and Resources (DER)
- Bill presentment and language changes
- Pole attachment agreements (SG)
- Cyber security
- Rate application (simplification and streamlining)

Niagara Peninsula Energy Inc.

Strategic Plan

Introduction

Niagara Peninsula Energy Inc. (NPEI) engaged Elenchus Research Associates Inc. ("Elenchus") to provide consulting services to facilitate the completion of its strategic planning process with its senior management and Board of Directors. The output will be the NPEI Strategic Plan for the next 3 to 5 years, terminating with the next planned Cost of Service Application to the Ontario Energy Board ("OEB").

The strategic planning process integrated the elements of NPEI's mission, vision, values, strategy, balanced scorecard with cascading measures and a strategic management system. The strategic plan will address stakeholder interests for business and regulatory requirements over the next three to five years.

The stakeholders were identified as follows: customers, regulator, Government, shareholders, employees, community, intervenors, media, and others.

Subsequent to setting the strategy, a corporate balanced scorecard was developed to summarize the business and regulatory performance measures, targets and significant initiatives necessary to achieve NPEI's goals. The scorecard can then be used to build cascading measures to the department and individual employee levels, as appropriate. That balanced scorecard will also assist NPEI leadership to communicate with the whole organization about the corporate strategy and ongoing progress against the goals, including celebrating successes and learning from challenges.

The strategic planning process was completed in several phases. Senior management met to identify management's perspective of NPEI's key strategic objectives for the next three to five years. An environmental scan was performed which included: an overview of the changing business and regulatory environment, a PESTLE (Political, Economic, Social, Technological, Legal/Regulatory, Ecological/Environmental) analysis of NPEI's macro environment, a SWOT (Strengths, Weaknesses, Opportunities and Threats) analysis of NPEI's business, existing plans and commitments and benchmarking.

Elenchus conducted interviews with each NPEI Board member where the objective was to seek Board member input, and identify areas of consensus and divergence as well as obtain any additional background material, to shape the content, format and value of the strategic planning process.

Senior management met subsequent to the Board interviews where the objective was to review the input from the Board and determine the impact on the initial draft strategic plan and draft implementation plan.

The Board of Directors and Senior Management met in February 2016 to finalize the Draft Strategic Plan.

The mission, vision and values were updated as a result of the strategic planning sessions as follows:

Mission: To deliver safe, efficient, and reliable electricity with excellent customer service and community value, provided by engaged employees.

Vision: To be recognized as exceptional in delivering services and value, to our customers and communities.

Values: To conduct ourselves with commitment to the values of:

- Integrity-we are ethical and our actions are truthful and trustworthy;
- Fairness-we treat everyone equally and free of bias;

- Responsibility-we provide services with safety first for our customers and employees;
- Respect-we listen to each other, see the value that each member of the team brings, and respect the needs of our stakeholders, and
- Transparency-we are open and accountable for our actions and decisions.

Executive Summary

Six focus areas of NPEI's business were identified as key strategy categories: Customers, Operational, Public Policy, People, Financial and Information Technology.

For each key focus area, objectives, goals, measures of success, targets and actions were developed.

The strategic plan will be revisited periodically to ensure NPEI is on track to achieve its mission, vision, and values. Customer engagement, performance based outcomes, and cost/benefit analysis will be an integral part in decision making and allocation of NPEI's resources. NPEI's cost of service rate application, distribution system plan and customer engagement plan will guide the use of resources over the next rebasing period of five years.

NPEI's objectives and goals for each of the six key focus areas of its strategic plan are summarized below.

NPEI will understand and deliver on customer expectations for reliable, high quality, cost-effective service by enhancing customer satisfaction and customer engagement.

NPEI will productively manage assets and resources to meet current and future customer needs by expanding the transformation and distributions systems to meet the electrical needs of current and future customers. NPEI will effectively maintain and refurbish aging plant facilities and equipment, provide a high level of service quality, enhance system performance and reliability while ensuring 100% level of compliance with the Ontario Regulation 22/04 and promote public safety awareness.

NPEI will successfully deliver public policies, be environmentally responsible and respond to the needs of our communities. Conservation and demand management (CDM) programs will be successfully implemented. The Green Energy Act requirements will be incorporated into the system for connections of renewable generation. Smart Grid initiatives to improve reliability will be implemented to accommodate embedded generation. NPEI will be environmentally responsible, continuously engage in its communities and develop its corporate image.

NPEI will invest in a safe, healthy and engaging workplace that attracts, retains and develops employees who contribute their best. Health and safety awareness will be promoted for NPEI employees and its “Safety Culture” will be strengthened. NPEI will gain a mutual understanding of its employees’ job expectations; provide the equipment, resources and training to do the job well. Feedback and recognition of employee and team performance will be provided on a timely and ongoing basis. Employees will be provided with development opportunities, integrated with a corporate succession plan to sustain operations.

NPEI will deliver sustainable shareholder value and meet or exceed regulatory expectations. Long-term financial viability will be maintained and NPEI’s balanced scorecard will be met or exceeded. NPEI will maintain regulatory compliance and meet or exceed the Ontario Energy Board’s (OEB) scorecard expectations. Shareholder value will continuously be enhanced and dividend expectations will be met.

NPEI will continually improve with a focus on innovation and technology in all areas of the business and provide integrated solutions to meet customer and business needs.

Customers

Objective

The objective related to customers is to understand and deliver on customer expectations for reliable, high quality, cost effective service.

Goals

- Enhance customer satisfaction through reliable high quality and cost effective service.
- Engage and understand our current and future customer expectations.

Measures of Success, Targets and Actions

1) Performance Category – Customer Satisfaction

i. Customer Satisfaction Survey

The Ontario Energy Board (OEB) introduced the Customer Satisfaction Survey in 2013. At a minimum, electricity distributors are required to measure and report a customer satisfaction result at least every other year. At this time the Ontario Energy Board is allowing electricity distributors' discretion as to how they implement this measure.

Niagara Peninsula Energy will conduct a Customer Satisfaction survey on a bi-annual basis using a third party. NPEI's target is to improve the customer satisfaction of 87% which was achieved in its first customer satisfaction survey in 2014. Actions include following up on key issues identified in the initial survey conducted in 2014 and implement improvements.

NPEI will develop and provide new customers with a Customer Service Welcome Package.

NPEI will provide information to the customer to ensure satisfaction is achieved. NPEI will understand from customer feedback areas requiring updates to its website, corporate communications, conditions of service to ensure the customer has information and policies readily available.

Post outage survey with results to exceed the current view of NPEI's effectiveness during an unplanned outage per Customer Service Satisfaction Survey: current status is very and somewhat effective. Improvement is required in response to questions, communicating updates periodically, posting information to website, social media and utilizing various media channels.

ii. First Contact Resolution

First contact resolution can be measured in a variety of ways. For NPEI, First Contact Resolution was measured based on NPEI representatives follow up directly with the customer. All calls are logged as issue resolved or follow up required. NPEI representatives completed customer calls with a survey question of "Have all of your issues been resolved today?"

NPEI had a First Contact Resolution of 93% in 2014. NPEI will continue to implement and track customer satisfaction and has set a target to exceed 93%.

iii. 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 (OEB) has prescribed a measurement of billing accuracy which must be used by all electricity distributors effective
October 1, 2014.

For the period from January 1, 2014 – December 31, 2014 NPEI issued more than 626,000 bills and achieved a billing accuracy of 99.58%. This compares favourably to the prescribed OEB target of 98%.

NPEI continues to monitor its billing accuracy results and processes to identify opportunities for improvement.

NPEI's target is to achieve 99.5% billing accuracy each year.

2) Performance Category – Customer Engagement

iv. Customer Engagement Plan

NPEI completed a customer engagement plan in 2014 which details NPEI's five year customer engagement strategy along with a customer engagement matrix. NPEI's target is to achieve 50% completion of monthly engagement plan activities including all conservation and demand customer engagement activities.

NPEI will monitor its progress of implementing the customer engagement plan and review, report and implement priority issues by providing on-going staff training, communications to customers, computer system adjustments and communication with other departments.

NPEI will participate in consultation activities with customers, service providers, and/or key stakeholders in its service territory to obtain feedback, educate and inform the customer. Consultation topics as outlined in customer engagement plan include: handling of outages, power quality and reliability, handling of capital improvement projects and construction work, renewable generation opportunities, programs, and modalities and connection procedures, approach to providing access to energy data to customers, electricity storage, price, billings and payment (NPEI's customer education work on electricity bills and price), conservation and demand management, customer communications and customer service experience.

NPEI will provide information to the customer to ensure satisfaction is achieved. NPEI will understand from customer feedback areas requiring updates to its website, corporate communications, conditions of service to ensure the customer has information and policies readily available.

v. Complete work requirements identified by Municipalities and the Region

NPEI will continue to engage in local and regional activities and sets a target of 90% completion of work requirements identified by Municipalities and the Region.

Identify present and future customer needs/preferences/priorities and prepare and implement appropriate responses in Distribution System Plan. This includes consultation work as outlined within the Customer Engagement Plan including Service territory stakeholder consultation work, participation in consultation with the Ontario Power Authority (OPA) and Hydro One Networks Inc. (HONI).

NPEI will attend public utility committee (PUC) meetings. Also NPEI will complete C5 forms related to customer engagement throughout the various departments. In addition, NPEI will be actively involved in Regional Planning activities and construct and implement facilities and programs as required.

Operational

Objective

Productively manage assets and resources to meet current and future customer needs.

Goals

- Expand the transformation and distribution systems to meet the electrical needs of current and future customers.
- Effectively maintain and refurbish aging plant facilities and equipment.
- Provide a high level of service quality
- Ensure 100% level of compliance with Regulation 22/04
- Promote public safety awareness
- Enhance system performance and reliability

Measures of Success, Targets and Actions

1. Performance Category – Asset management

i. Distribution System Plan Implementation

Niagara Peninsula Energy prepared a Distribution System Plan (DSP) and filed it with the Ontario Energy Board in conjunction with the 2015 Cost of Service rate application. The DSP outlined NPEI's Asset Management process and capital expenditure plan over the next five years. The DSP is used as a guide in preparing NPEI's annual capital budget. NPEI will implement the DSP through the execution of projects, review and adjust accordingly using its resources and processes appropriately. NPEI's target is 90% of the projects identified in the annual capital plan to be completed.

NPEI will implement reporting within the Asset Management System (GIS) to review average asset lives of major equipment and conduct a conditional review of such major equipment.

2. Performance Category – Asset maintenance

ii. Reduce reactive activities related to equipment failures

NPEI will track and report the number of trouble calls on a quarterly basis. The causes of the trouble calls will be determined where possible and long-term solutions will be analyzed.

3. Performance Category – Service quality

iii. New residential/small business services connected on time

The OEB's target for new residential/small business services connected within a five-day timeline is 90% of all new low voltage (those utilizing under 750 volts). NPEI will track and report quarterly the percentage of new connections within the five-day window. NPEI will adjust its processes and procedures to ensure compliance with the OEB's target is met.

NPEI's target is to exceed 90%.

iv. 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's target is to exceed 95%.

v. Telephone calls answered on time

The OEB mandates that 65% of telephone calls are answered on time. NPEI will report the percentage of telephone calls answered on time on a quarterly basis. NPEI's target is to exceed 81%.

4. Performance Category – Safety

vi. Level of compliance with Ontario Regulation 22/04 and serious electrical incidents index: Number of general public incidents and rate per 10, 100, 1000 km of line

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. NPEI will review the inspection results and conduct the Regulation 22/04 audit on an annual basis.

Over the past four 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.

NPEI reported zero (0) fatalities due to contact with its infrastructure. The result was a total of zero (0) incidents with a rate of 0.000 incidents per 1,000 km of line for 2014. NPEI's target continues to be zero incidents.

vii. Complete public awareness on safety survey

The OEB mandated that each utility conduct a public awareness on safety survey by the end of the first quarter in 2016. NPEI will conduct the survey using a third party provider and report the results. NPEI will review the results of the survey and take the necessary steps to communicate and improve its results over the following year.

NPEI will update its website, advertise quarterly in the newspaper (seasonal - storms, tree trimming, call before you dig) and update the plan for traffic safety and construction job site safety.

5. Performance Category – System Reliability

viii. Customer Average Interruption Duration Index (CAIDI)

NPEI will report quarterly the CAIDI statistics and implement measures to improve its performance. NPEI will adhere to the Distribution System Code with respect to tree trimming and equipment inspections. NPEI will adjust its annual tree trimming program and equipment maintenance programs as necessary.

ix. System Average Interruption Duration Index (SAIDI)

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. This statistic is included on the OEB's annual scorecard.

SAIDI = Sum of all interruptions durations/Total number of customers served.

NPEI's target is a five year average between 1.77 and 5.31.

x. System Average Frequency Index (SAIFI)

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. This statistic is included also on the OEB's annual scorecard.

SAIFI = Number of customer interruptions/Total number of customers served.

NPEI's target is a five year average between 1.06 and 1.94.

xi. Momentary Average Interruption Frequency Index (MAIFI)

NPEI's target is to reduce the number of momentary interruptions. NPEI will track and report quarterly the momentary average interruption frequency index (MAIFI) on a quarterly basis. The capital investment project plan will be reviewed to ensure MAIFI issues are addressed.

xii. Power quality

NPEI will track and report quarterly the number of customer complaints related to low voltage issues. System analysis will be performed and solutions proposed to improve power quality.

xiii. Enhanced redundancy/capacity

NPEI will report the number of projects addressing redundancy/capacity in the annual capital budget and report quarterly the percentage completion of these projects.

Public Policy

Objective

The objective related to public policy is to successfully deliver public policies, be environmentally responsible and respond to the needs of our communities.

Goals

- Successfully implement conservation and demand management (CDM) programs.
- Incorporate the Green Energy Act requirements into the system.
- Implement Smart Grid initiatives to improve reliability and accommodate embedded generation.
- Be environmentally responsible, continuously engage in our communities and develop our corporate image.

Measures of Success, Targets and Actions

1. Performance category – Conservation and Demand Management (CDM)

i. Achieve annual conservation target which will be reviewed by the Independent Electrical System Operator (IESO)

NPEI will promote the efficient use of electricity through education and delivery of conservation initiatives. NPEI will educate and promote the Combined Heat and Power (CHP) program to its large customers. NPEI will carry out the Hotel/Motel CDM pilot project to ensure it becomes a local and province wide program. NPEI will engage in a CDM pilot project related to the Agriculture sector which may include greenhouses, wineries, and medical grow-ops to improve LED lighting, CHP, refrigeration and collaborate with the gas utility to achieve maximum CDM savings in a cost shared manner.

NPEI's target for net cumulative energy savings for 2016 is 10,836.7 MWh. The percentage achieved will be reported annually and the CDM plan will be adjusted accordingly for significant variances from the target.

2. Performance category – Connection of renewable generation

ii. 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 2014, NPEI did not have any CIAs. NPEI outsources the CIA work to an engineering consultant. NPEI's target is to complete 100% CIA's within the timelines prescribed.

iii. New Micro-embedded generation facilities connected on-time

NPEI will connect new micro-embedded generation facilities (micro FIT projects of less than 10 kW) within the prescribed time frame of five business days. The minimum acceptable performance level for this measure is 90% of the time. NPEI's target is to exceed 90% of new micro-embedded generation facilities within five business days.

3. Performance category – Green Energy

iv. Approval of plan submissions by regulators

NPEI will complete the required paperwork and establish schedules related to plan approvals required by the Green Energy Act. NPEI will implement 15% of the five year plan by expanding the Wi-max network which is part of the Smart Grid initiatives.

NPEI will replace outdated reclosures and switchgear with state of the art electronically controlled devices incorporated into the network. NPEI will utilize information derived from the Wi-max 1.8 MHz network by control room personnel during outage events.

v. Participate in Niagara Sustainability initiative and reduce NPEI's carbon footprint

NPEI will capture benefit from embedding sustainability into their operations to improve efficiency, engage employees (establish cross-departmental "green team"), reduce costs and prepare for the low carbon economy.

Encourage employee involvement in the community and sponsor and participate in Environmental Programs with the Communities we service.

People

Objective

Invest in a safe, healthy and engaging workplace that attracts, retains and develops employees who contribute their best.

Goals

- Promote health and safety awareness for NPEI's employees and strengthen NPEI's "Safety Culture"
- Gain a mutual understanding of NPEI and employee job expectations, and provide the equipment, resources and training to do the job well.
- Provide timely ongoing feedback and recognition of employee and team performance.
- Provide employees with development opportunities, integrated with a corporate succession plan to sustain operations.

Measures of Success, Targets and Actions

1. Performance category – Health and Safety

i. Increase the number of days without a loss time/injury; reduce the number of days lost due to injury or illness

NPEI will schedule review training or certification training for the management team on legal requirements under the Occupational Health and Safety Act (OHSA), Violence & Harassment documentation, and investigations. Accident / incident investigation policies and procedures will be updated.

Improve off-the-job safety programs (Health & Safety/ Wellness at Home). Communicate and educate the reasons why "I" work safely. Review at safety meetings human resources/ wellness / safety newsletter, recognition, and the annual safety BBQ.

Implement the new employee and family assistance plan (EFAP) (with Shepell). Implement information sessions for management and staff. Continuously promote to all levels of the organization throughout the year - plan developed.

2. Performance category – Communication

ii. Regular one-on-one meetings with Supervisors and Employees

NPEI will communicate the importance of the job as a part of NPEI's overall business strategy (in new hire orientation, annual reviews, goal setting meetings), mid-year performance progress meetings. NPEI will ensure regular one-on-one meetings are held with supervisors and employees and report quarterly.

iii. Regular departmental meetings

NPEI will ensure regular departmental meetings are held and will report on a quarterly basis. Employees will be kept informed of important issues through the quarterly CEO report, group meetings, Recognition Committee newsletter, and company-wide meetings. With the use of the corporate balanced scorecard, NPEI will share results, celebrate successes and learn from challenges.

3. Performance category – Performance assessment

iv. Performance assessments completed on a timely basis

NPEI will administer performance assessments at a minimum of on an annual basis. Timely formal and informal feedback will be provided to employees. Implement an improved performance management process. Enhancements and changes will be made to improving the performance assessment forms, documentation and process. Training will be provided to employees responsible for completing performance assessments. NPEI will plan and implement or enhance methods of individual, team and corporate recognition.

4. Performance category – Leadership and succession planning

v. Leadership development plan implemented

NPEI will complete succession planning annually and periodically throughout the year as necessary. In 2016, NPEI will complete a pilot project to enhance the Leadership process to develop future leaders.

Financial

Objective

Deliver sustainable shareholder value and meet or exceed regulatory expectations.

Goals

- Maintain long-term financial viability and meet or exceed NPEI's Balanced Scorecard financial expectations
- Maintain regulatory compliance and meet or exceed Ontario Energy Board (OEB) scorecard expectations.
- Continue to build shareholder value and meet dividend expectations.

Measures of Success, Targets and Actions

1. Performance Category – Financial Ratios

i. Profitability Ratio

The profitability ratio is defined as: a) Earnings before Interest, Taxes, Depreciation and Amortization (EBITDA) and b) Return on Assets (ROA). NPEI's target for a) EBITDA is to achieve higher than 40% and b) ROA greater than 2.5%.

NPEI will prepare the capital and operating budgets with all departments in accordance with the 2015 COS rate application and obtain Board of Director approval.

On a monthly basis NPEI will report actual results to budget and prior year, investigate significant variances and communicate to the Finance Committee and Senior Management. On a quarterly basis, NPEI will report these results to the Board of Directors.

NPEI will communicate financial target results on a quarterly basis to the Board of Directors and Senior Management.

ii. Liquidity Current Ratio

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 will include financial target ratios set by the corporation and OEB's scorecard in the budget report.

On a monthly basis NPEI will report the liquidity current ratio, investigate significant variances and communicate to Finance Committee and Senior Management. NPEI’s target is between 1.35 and 1 and 1.8 and 1.

iii. Debt covenants met

NPEI currently is indebted to Scotia bank and the Toronto Dominion Bank.

The bank loans payable to Scotia Bank have the following general security; General Security Agreement ranking 1st over the Bank's share of the Borrower's present and future personal property as defined under the Inter-Creditor Agreement, with appropriate insurance coverage, loss if any, payable to the Bank. The Inter-Creditor Agreement is between Scotia Bank and The Toronto-Dominion Bank.

The conditions related to the Scotia Bank debt are as follows: The ratio of Total Debt (including contingent liabilities) to Capitalization is not to exceed 0.70:1. Capitalization is defined as total debt and total equity plus contingent liabilities. The ratio of EBITDA to interest expense plus the current portion of long-term debt and capital leases, calculated on a rolling 12 month basis, is to be maintained at all times at 1.50:1 or better. EBITDA is defined as net income before extraordinary and other non-recurring items plus interest, income tax, depreciation and amortization expenses during the period.

The conditions related to the Toronto-Dominion Bank debt are as follows: firstly, the loan is secured by a general security agreement pursuant to the Inter-creditor agreement between TD bank and Scotia bank and secondly the Corporation is required to maintain a minimum debt service coverage ratio of 1.20:1. Debt service coverage is defined as: EBITDA less cash taxes, less 40% net cap-ex divided by the sum of the total cash interest expense plus mandatory principal payments. The Corporation must also maintain a maximum debt to capitalization ratio of 0.60:1. Debt is defined as all third party interest bearing debt and non-interest debt, including guarantees, not subordinated to these credit facilities. Capitalization is defined as the sum of total debt, guarantees, shareholders' equity, contributed capital, and preference share capital net of any goodwill and other intangible assets such as deferred transition costs.

NPEI will ensure sufficient long-term debt financing exists and its bank covenants are met.

2. Performance Category – Regulatory compliance

iv. File all regulatory filings accurately and on time

NPEI will prepare an annual calendar outlining regulatory filings with internal submissions due dates and distribute to supporting departments.

NPEI expects to be successful in filing its 2016 to 2019 IRM rate applications and its 2020 Cost of Service application with the OEB.

3. Performance Category – Cost control

v. Achieve Efficiency Cohort = 3

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 2014, for the second year in a row, 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 2014, 47% (34 distributors) of the Ontario distributors were ranked as "average efficiency"; 28% were ranked as "more efficient"; 25% were ranked as "least 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. NPEI's target is Group 3 for 2015 and 2016.

NPEI will prepare its internal scorecard on a quarterly basis for all targets within NPEI's control to calculate.

vi. 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 2014 is $742 /customer which is a 10.4% increase over 2013. NPEI filed its final smart meter application with the Ontario Energy Board in 2014. As a result of this application, smart meter costs incurred in prior years were recorded as capital and operating expenses in 2014 which is the year of final disposition of smart meter costs. The impact was an increase of $1.6M in capital costs and $1.4M in operating expenses. NPEI's Total Cost per Customer has averaged $681 over the period 2010 through 2014. Similar to most distributors in the province, NPEI has experienced increases in its total costs required to deliver quality and reliable services to customers. Province wide programs such as Time of Use pricing, growth in wage and benefits costs for our employees, as well as investments in new information systems technology and the renewal and growth of the distribution system have all contributed to increased operating and capital costs. 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 initiatives will continue in order to ensure customers have an opportunity to share their viewpoint on NPEI's capital spending plans.

NPEI's goal for 2015 and 2016 is to achieve a Total Cost per customer between $670 and $690.

vii. 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. NPEI's 2014 rate is $19,458 per Km of line, an 11.8% increase over 2013. NPEI filed its final smart meter application with the Ontario Energy Board in 2014. As a result of this application, smart meter costs incurred in prior years were recorded as capital and operating expenses in 2014 which is the year of final disposition of smart meter costs. The impact was an increase of $1.6M in capital costs and $1.4M in operating expenses. As a result, cost per Km of line has increased year over year with the increase in capital and operating costs. See above cost per customer section for cost driver commentary. NPEI continues to seek innovative solutions to help ensure cost/km of line remains competitive and within acceptable limits to our customers.

viii. Regulatory Return on Equity

NPEI's 2015 distribution rates were approved by the OEB and include an expected (deemed) regulatory return on equity of 9.00%. 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. NPEI's target for 2015 and 2016 is to achieve between 6.0% and 12.0%.

4. Performance Category – Shareholder value

ix. Annual dividend is paid to Shareholders within the Shareholders expectations

NPEI will communicate the expected annual dividend with both the Board of Directors and the Shareholders. Shareholders will be encouraged to attend the Annual General Meeting (AGM). NPEI will provide consultation and advice to shareholders as required.

x. Provide consultation and advice to Shareholders as required.

NPEI will enhance communication to the Board with standard quarterly reporting, for example: agenda items will be based on the Strategic Plan / Scorecard; priority cyclical and/or currently topical subjects; scorecard updates and other management reporting using a consistent format with reference to the respective Strategic Plan goals, measures, benchmarking and approach of setting out the situation, opportunity, pros/cons, and ask the Board and any next steps.

xi. Prepare annual CEO report.

NPEI will complete an annual CEO report and distribute it to the Board and the Shareholders.

Innovation and Technology

Objective

Continually improve with a focus on innovation and technology.

Goals

- Continuously improve productivity and innovation in all areas of the business.
- Provide integrated technical solutions to meet customers and business need.

Measures of Success, Targets and Actions

1. Performance Category – Innovation and Technology

i. Process improvement projects are implemented and efficiencies achieved

NPEI will implement business process re-engineering to drive innovation and increased productivity. NPEI will stay current with industry, sector and regulatory changes and will plan and set targets for benefits of Grid Smart City. NPEI's target is to implement 100% of the annual projects identified and will report quarterly the percentage completion of each project.

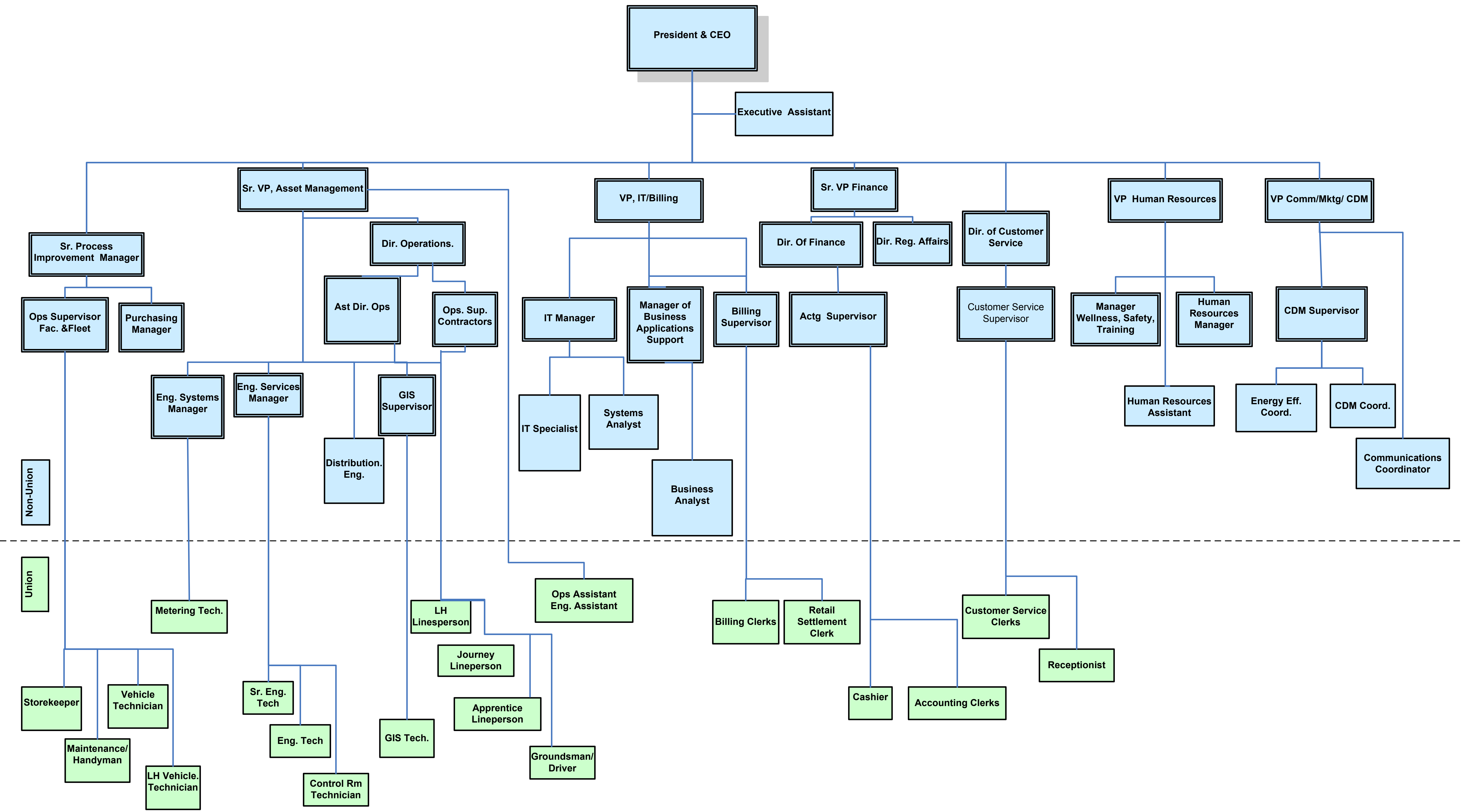
ii. Provide the number of customer related projects and the number of business solutions projects

NPEI will maintain and update the customer web portal, integrate web solutions into customer engagement activities for customer service, billing, conservation, engineering, outage management and corporate initiatives. Enterprise solutions will be managed to integrate business needs to enhance operational efficiencies. New technology will be investigated related to the Wi-Max project and the SCADA project. NPEI will report the number of projects completed on a quarterly basis.

Appendix 1-9

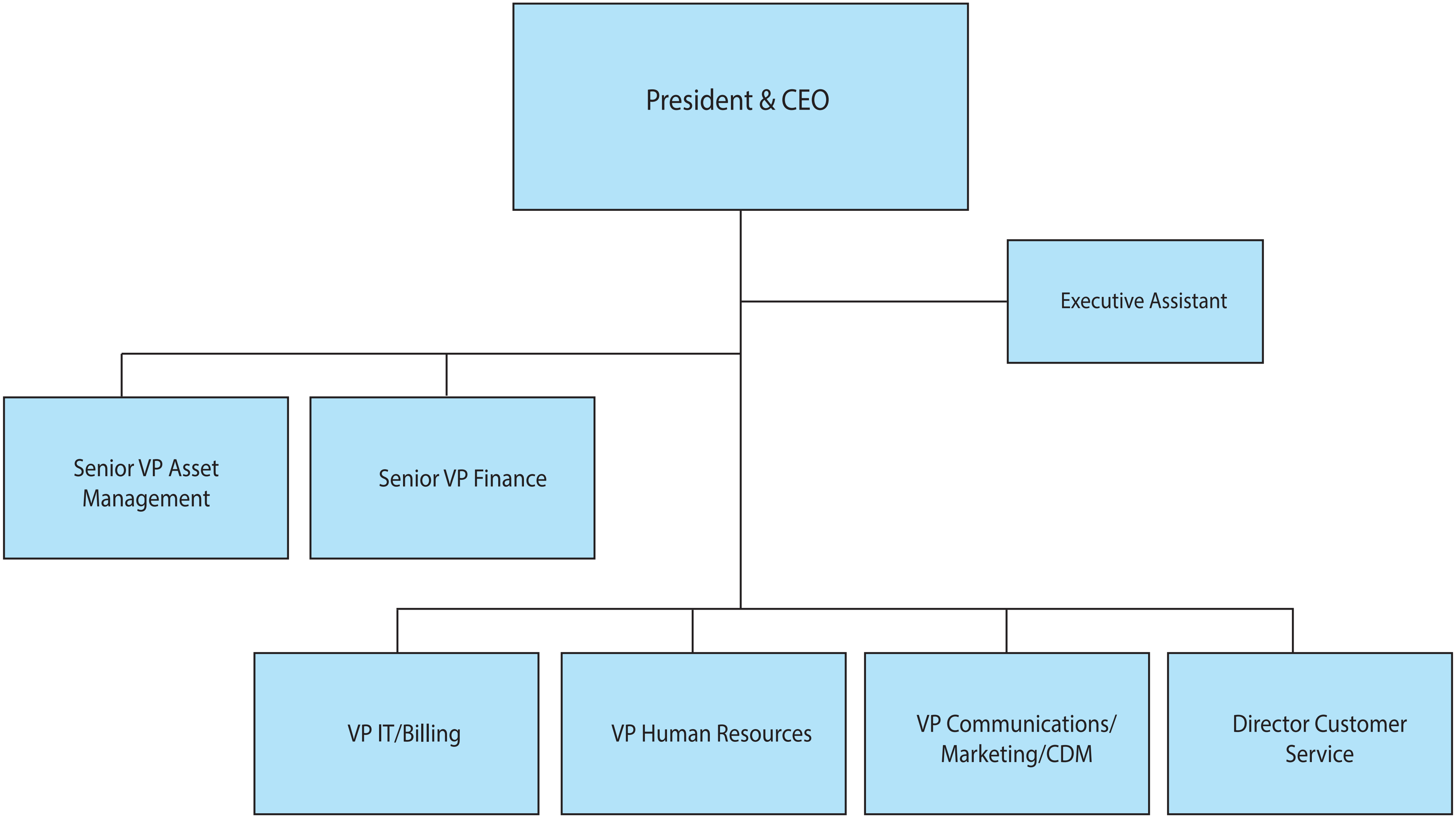
NPEI’s Organization Structure

Niagara Peninsula Energy Inc. Organizational Chart 2019



Appendix 1-10

NPEI's Senior Executive Management Structure


President & CEO
Executive Assistant
Senior VP Asset Management
Senior VP Finance
VP IT/Billing
VP Human Resources
VP Communications/ Marketing/CDM
Director Customer Service

Appendix 1-11

NPEI's Board of Directors Governance and Policies

npe niagara peninsula energy inc.
Your Local Utility

CORPORATE GOVERNANCE
INTRODUCTION & OVERVIEW

December, 2019

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Role of the Board of Directors

The role of the Board is to provide stewardship of the organization and to add to the long-term success of the Corporation through attending to the following key items:

- Interpret and oversee implementation of shareholder direction but must always act in the best interest of the Corporation.
- Optimize long-term shareholder value.
- Lead a business that is strong, resilient, sustainable and financially responsible.
- Add value to the Corporation by guiding its strategic management.
- Together with the President/CEO and Senior Management team, create, adopt, and implement a strategic plan and policies using a disciplined planning process, periodically updated and modified from business performance feedback and external environmental (business) scans to be recommended and approved by the Board of Directors.
- Monitor and report the performance of the organization to ensure the success of the Corporation.

The Board represents the interests of the Shareholder but must always act in the best interest of the Corporation. It complies with the Shareholder direction in force, from time to time, and it communicates events that the Board considers material to the Shareholder.

Corporate accountability rests on the principle of enhancing the economic value to the Shareholder. The Board's sole official connection to the operational organization is through the President/CEO.

Role of Board of Directors

The Board of Directors is responsible for ensuring that the entity has a vision and a strategic plan is in place, with operating practices consistent with the ability of the organization to meet its goals and objectives.

The Board of Directors hires the President/CEO and determines his/her compensation. The Board of Directors works collaboratively with the President/CEO on annual performance goals aligned to the current corporate strategic plan. It holds the President/CEO accountable for achieving agreed upon goals and meeting specific performance targets to determine annual compensation.

Individual Board Members have no independent decision-making authority. The Board's only decision-making power comes from its collective authority as the duly constituted Board of the Corporation, meeting under the by-laws of the Corporation. Individual Board members may not direct management in any way, and should not purport to have any decision-making authority on behalf of the Board to outside parties, unless authorized by the Board pursuant to a Board resolution.

While individual Board members cannot direct any action by the Corporation, the Board members have an important role in providing advice to senior management at Board and Committee meetings. Each member brings a unique set of skills and expertise to the Board. Both the Board and senior management should benefit from this resource.

To the extent that a Board member requests information of management, such a request, outside of Board or Committee meetings, shall be made through the Chair.

The members of the Board do not manage the organization. The Board sets broad parameters, establishes policy and controls, ensures that management is in place to achieve the organization's objectives, and it monitors management's performance against the established objectives as outlined in the Strategic Plan.

The law imposes a high standard of care on Board of Directors. They must use due diligence in discharging their duties. They must take reasonable steps to inform themselves via management of the affairs of the Corporation, and must make their own assessments of the proposals presented to them by management.

They must **always** act in the best interests of the Corporation. This obligation extends outside of Board meetings. The Board of Directors' loyalty must be to the Corporation, and not a political or personal agenda, and the Board of Directors must have sufficient time and capacity to stay informed about, and carefully examine, the affairs of the Corporation.

In addition to their obligations to act diligently, honestly and in the best interests of the Corporation, various statutes impose personal liabilities on Board of Directors and it is up to each Board of Director to make himself/herself aware of such statutes.

Conflicts of Interest

A Board of Director of a corporation who is a party to (or is interested in), either directly or indirectly, an existing or proposed material contract or transaction with the Corporation must disclose that interest, even if the material contract or transaction is not one which, in the ordinary course of the Corporation's business, would require approval by the Board of Directors. If the material contract or transaction is one which does require Board approval, the Board of Director who has declared an interest is not permitted to vote on the resolution approving it. Refer to Orientation Manual.

Role of the Board Chair

The Board Chair chairs all Board meetings. The Chair serves at the pleasure of the Board.

In consultation with the President/CEO, the Chair sets the agendas for the Board meetings, ensures the meeting discussions are focused, ensures there is proper decorum at meetings, ensures good information flow and ensures decisions are clear and supported by resolutions where necessary. The Chair ensures regular and appropriate communication with the Shareholder, the Board of Directors and the broader community.

The Chair ensures that meetings are conducted in an orderly fashion and that all Board of Directors are encouraged to actively participate in Board deliberations. The Chair must be balanced; exercising good judgement and common sense in moving the business of the Board forward and ensuring the Board's Corporate Governance Guidelines are adhered to. By nature of the position, the Chair is frequently an informal sounding board for the President/CEO and is the conduit for the transmission to the President/CEO, on behalf of the Board, any emerging Board views or concerns so that management can address the issues in a timely fashion. The Chair is, ideally, the fulcrum upon which accountability turns. He/she must ensure a viable vision and mandate for the organization supported by good governance practices in achieving the necessary accountability of management to the Board, and the Board to the Shareholder.

The role of the Chair necessitates the Chair devoting more time for Board business than the other Board of Directors. The Chair is a non-executive position, that is, the Chair, like the other Board of Directors, is not part of the management team. This is necessary so that no confusion arises as to the role of the Board.

Organization of the Board

Because of the over-arching stewardship role of the Board, a Board may choose to delegate some of its more detailed review of activities to specific Committees for informed discussion.

The Board and Board Committee meeting dates should be established well in advance. A generally accepted practice is to establish meeting dates, as well as an Annual Meeting date for the following year, three to four months before the existing year-end.

At a minimum, four Board meetings a year are desirable. In times of unprecedented change or crisis, additional meetings are advisable in order to ensure that management is responding expeditiously to the business and organization challenges it is facing. Additional meetings would also provide management with the opportunity to draw on the collective expertise of the Board members.

Normally, materials for Board and Committee meetings should be delivered to Board members at least **5** days prior to the meeting date.

Enacting Resolutions

Most effective Boards try to manage on a consensus basis so that decisions are arrived at with something close to unanimity. When a vote is necessary a simple majority will prevail. Once a decision of the Board has been reached, and all Board of Directors have had clear opportunity to express their respective opinions, the decision of the Board shall prevail. Board members must respect and abide by decisions of the Board.

The Board of Directors may enact resolutions at a meeting, or may pass a resolution in the absence of a meeting in writing if all Board of Directors sign such resolution. A quorum of Board of Directors may call a Board of Directors meeting upon the giving of at least 5 days notice to each individual involved.

Meetings are normally held at the registered office of the Corporation, or by telephone. A majority of the number of Board of Directors constitutes a quorum and a majority of a quorum can enact resolutions at a meeting. Alternatively, **all** of the Board of Directors can enact a resolution without meeting by signing a written text of the resolution.

Role of Committees

Committees should act as the arms of the Board, with responsibility for monitoring assigned areas and developing policy and recommendations for the consideration of the Board as a whole. Committees should not normally be asked to act for the Board or to direct the administration. The role of Committees is to:

- Assist the Board with strategy and policy development.
- Comment and advise on preliminary recommendations of management to the Board based on Board approved goals and policy statements.
- Make recommendations to the Board based on recommendations from Committees.

Written minutes must be kept of all Committee meetings and distributed to the whole Board. The whole Board should only deal with a report from a Committee when a specific action is proposed or if a serious problem is encountered.

Communications with Shareholder

Communications to the Shareholder on strategic and policy level issues should be in writing and that the sum and substance of these communications shall be approved by the Board prior to being communicated to the Shareholder.

Independent Advice

The Board shall be authorized to obtain, as it deems necessary for the fulfillment of its duties, any independent advice it requires (for example, legal counsel, compensation expertise etc.). This shall be authorized pursuant to a resolution passed by the Board.

Board Policies

Board policies established within these Corporate Governance Overview fall into four general groups:

A. Mission/Results-related: *what market needs are to be met and at what relative worth or cost.*

B. Executive Limitations: *the principles of prudence and ethics that limit the choice of means to achieve the Mission/Results.*

C. Board-Executive Relationship or Board-President/CEO Linkage: *how power is passed to the President and the manner in which the use of that power is assessed*

D. Board Process: *the manner in which the Board represents the Shareholder and provides strategic leadership to the organization.*

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CORPORATE GOVERNANCE
BOARD of DIRECTORS
POLICIES

December 2019

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NEW DIRECTOR ORIENTATION POLICY

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1. GENERAL PURPOSE AND SCOPE

This policy statement describes the orientation process provided to each new Director of Niagara Peninsula Energy Inc. and its subsidiary companies (collectively referred to as "NPEI" or the "Company") to familiarize the new Director with Board requirements, practices and standards as well as the operations of the companies within the first four weeks of appointment.

In general, this policy provides for an overview of the minimum requirements for a proper orientation process and mandates that orientation shall occur.

2. ORIENTATION POLICY

A. New Directors will be provided with an orientation program which will include written information about the duties and obligations of Directors, the business of the company, documents from recent Board meetings, opportunities for meetings and discussion with senior management and other Directors as appropriate, plus tours of the Company's facilities. The details of the orientation will be tailored to reflect that individual's needs and areas of interest as well as required components. The Chair and the President/CEO will jointly facilitate the orientation program.

B. When appointed to a Board Committee, Directors will be provided appropriate terms of reference of the committee, information and orientation to prepare them to participate effectively. The Chair of the Committee will facilitate committee orientation.

STANDARDS OF CONDUCT POLICY

1. GENERAL PURPOSE AND SCOPE

This policy statement describes the general duty of each Director of NPEI and its subsidiary companies to disclose any conflict of interest, whether actual or perceived where the Director may realize a personal benefit from the actions taken by the Company.

In general, this policy provides assurance that the Company's Directors will serve in the best interest of the company and remain independent from potential concerns of conflict. Where this cannot be achieved, the director must disclose the nature of the conflict and the potential benefit to the director.

2. GENERAL STANDARDS OF CONDUCT

Every director and every officer of a Crown corporation in exercising his/her powers and performing his/her duties shall:

(*a*) act honestly and in good faith with a view to the best interests of the corporation; and
(*b*) exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances.

3. CONFLICT OF INTEREST

Common Law

In general, common law prohibits a Director from doing business with the Company. However, a Director may from time to time be in a business which routinely provides goods and services to NPEI and similar companies. The general standard is very restrictive and the following procedures will be adhered to when it is deemed appropriate that a Director enter into a commercial contract with the Company.

i Written notice – The Director shall notify the Board in writing of his or her interest at the time the Director first becomes interested in a transaction.
ii Abstain from voting – the Director shall abstain from voting on any resolution to approve the contract or transaction in question.
iii Fair and reasonable – The final consideration is that the contract or transaction must be fair and reasonable to the Company at the time it is approved or confirmed.

STANDARDS OF CONDUCT POLICY

4. DUTY TO DISCLOSE

i Each Director has a duty to disclose any potential conflict of interest.
ii Each Director has a duty to disclose any information that he or she may have by virtue of another relationship that is of vital importance to the Board.
iii Each Director has a duty to avoid being in a position of breaching a fiduciary responsibility to NPEI by virtue of owing the same responsibility to another organization.

A Director may hold a directorship, be an officer or have another material interest in a corporation or person other than NPEI. Without affecting the operation of any rule of law,

a) A Director who holds such an interest in such other corporation or person shall disclose the same in writing to the Board forthwith upon his/her appointment and annually, afterward;
b) Where a Director acquires such an interest in such other corporation or person after his/her appointment to the Board, he/she shall disclose the same in writing to the Board forthwith after he/she acquires such an interest.

5. RESPONSIBILITY OF LOYALTY & CONFIDENTIALITY

A Director's personal interest, or the sole interest of the shareholder, should not be allowed to interfere with that Director's responsibility of loyalty to NPEI. Each proposal submitted for the consideration of the Board should be considered essentially on its merits and with a view to the best interests of NPEI.

Directors should communicate to the Chair any information that may be necessary or useful to NPEI management in the conduct of NPEI's business.

Directors should not communicate, or allow to be communicated to any person not entitled thereto any information related to the business and affairs of NPEI which has not been made available, nor allow any such person to have access to or inspect any books or documents relating to the business and affairs of NPEI made available to them as Directors, or belonging to or in the possession of NPEI.

Communications with municipal or government officials in respect of NPEI's business and affairs are the prerogative of the Chair and the President/CEO. Accordingly, Directors should not initiate such communications unless requested to do so by the Chair.

STANDARDS OF CONDUCT POLICY

6. RESPONSIBILITY OF CARE AND PRUDENCE

Generally, a Director is expected to follow the "business judgment rule" which requires the Director to act at all times in accordance with what the Director believes to be in the best interests of NPEI, relying on past experience, skill and applying plain common sense. Acting prudently implies acting with care and caution in trying to foresee probable consequences of his/her decisions, with a view to the best interests of NPEI. In addition, decisions must be based on the Director's informed and reasoned business judgment that is not vitiated by any conflict of interest.

7. RESPONSIBILITY OF DILIGENCE

A Director must familiarize himself/herself with the policies, businesses and affairs of NPEI so that he/she may attend meetings and be prepared to express his/her point of view on any matter put forward for consideration by the Board. In this respect a Director may rely in good faith on financial statements represented to him/her by an officer of NPEI or in a report of the auditor as fairly reflecting the financial condition of NPEI, or on a report of a lawyer, accountant, engineer, appraiser or other person whose position or profession lends credibility to a statement made by such person.

In connection with this responsibility of diligence, Directors should remember that a director of NPEI is deemed to have consented to any resolution passed or action taken at a meeting, unless (i) in the case of a Director who is present at the meeting, he/she requests that written notice of his/her dissent be entered in the minutes of the meeting, gives notice of his/her dissent to the Secretary before the meeting is adjourned or sends his/her written dissent immediately after the meeting (provided he/she did not vote in favour or consent to the resolution) and (ii) in the case of a director who is not present at the meeting, he/she causes written notice of his/her dissent to be placed with the minutes of the meeting or he/she sends written notice of his/her dissent to the head office of the corporation, within seven days after he/she becomes aware of the resolution or action taken at the meeting.

DIRECTOR'S REMOVAL POLICY

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1. GENERAL PURPOSE AND SCOPE

This policy statement describes the circumstances and process under which an involuntary termination of a Director's service may be required.

In general, this policy provides for an overview of the requirements for removal of a Director of the Board should it be deemed that their continued service on the Board is no longer effective or even counter-productive.

2. REMOVAL POLICY

A. It is understood that the respective Shareholder retains the sole right, subject to recommendations of the Board, (and considering clause 3 of 'Attendance and Participation' policy), to request the replacement of a current Director of the Board with whom they have lost confidence.

B. It is a recognized practice of good governance and a policy of the Board that Directors should retain their independence of thought as well as the duty of honesty, loyalty, care, diligence, skill and prudence. However, should a circumstance arise that is determined by the majority of the Board that a Director is no longer effective or is counter-productive; the Board may recommend to the Chair that the Director be removed.

C. In the circumstance where the Chair has been requested to proceed with the replacement of a Board member, the Chair will notify the Shareholder and provide details of the circumstances surrounding the request. Should the Shareholder determine that such action is necessary; the Shareholder will proceed with appropriate notification of the Director. In all cases, the exercise of tact and diplomacy and confidentiality is required.

D. A Director who has been involuntarily removed from the Board may still retain certain liabilities of current Directors with respect to the actions of the Company prior to his or her removal from the Board.

MEETING PARTICIPATION POLICY

1. GENERAL PURPOSE AND SCOPE

This policy statement describes the general expectation of meeting participation of a Director of NPEI and its subsidiary companies (collectively referred to as the "Company").

In general, a Director is expected to make all reasonable efforts to attend the Board meetings of the Company. At Chair's discretion, other means of attendance may be available to the Director.

2. ATTENDANCE AND PARTICIPATION POLICY

A. General

1. A Director should attend all official meetings of the Board that are duly called by the chair.
2. Subject to the exception indicated below, a Board member shall resign if he or she misses more than three (3) consecutive meetings annually duly called by the chair.
3. If a Board member misses more than three (3) Board meetings annually owing to extenuating circumstances, the Board shall the have right to waive the required resignation of the Director.

B. Participation at meetings

A Director is expected to participate at all meetings in order for the Company to benefit from the judgement and experience of the Director. The Director should engage in full and frank discussion on all matters before them.

BOARD MEMBER EXPENSE REIMBURSEMENT POLICY

1. GENERAL PURPOSE AND SCOPE

This policy statement describes the general expense reimbursement guidelines for a Board Director of NPEI and its subsidiary companies (collectively referred to as the "Company").

In general, a Director may incur expenses in the course of discharging his or her responsibility as a Director. Subject to the limitations outlined below, a Director shall be reimbursed for these expenses upon submission of an expense report and valid original receipts.

2. REIMBURSEMENT POLICY

General

A Director is entitled to receive reimbursement, as approved by the Board of Directors in accordance with the Shareholder per calendar year, for general expenses that he or she incurs in the course of discharging his or her duty as a Director. The Director is expected to submit an expense report with all supporting receipts. The Chair of the Board will approve the expense report. In the case of expenses incurred by the Chair of the Board, an expense report and supporting receipts will be submitted to the Chair of the Finance Committee for approval.

Continuing Education

A Director is entitled to receive reimbursement, as approved by the Board of Directors in accordance with the Shareholder per calendar year, for continuing education courses that contribute to the knowledge base of matters relating to corporate governance and Board operations while also enhancing their skills as Directors. Reimbursement will include tuition or registration fees; books; meals, hotels and mileage reimbursement, in accordance with the Company travel policy rates and standards for management.

Other

If a Director is requested by the Board to represent the Company in an official capacity (i.e. a conference or meeting), as a Director of NPEI, the Director shall be reimbursed for all reasonable costs of fulfilling this duty.

DIRECTOR EDUCATION POLICY

1. GENERAL PURPOSE AND SCOPE

This policy statement describes the general duty of each Director of NPEI and its subsidiary companies (collectively referred to as "Company") to be educated on matters of current Board governance and the various business matters that are their responsibility as they occur from time to time.

2. EDUCATION POLICY

(a) The Company will provide a Director orientation and education program for all individuals recruited to the Board.

(b) The Company shall make available such resources as may be reasonably required for any industry-related or governance-related continuing education requirements of its Directors.

(c) Each Director shall have the responsibility for maintaining a sufficient knowledge base of matters relating to corporate governance.

(d) Each Director shall consider what continuing educational requirements he/she may be required on an ongoing basis in connection with discharging the Director's duty. Should additional training or courses be required in order to continue to exercise the care, diligence and skill that a reasonably prudent person would exercise in the course of serving as a member of Board of Directors, then additional training should be sought.

The training requirements should be reviewed through the Chair of the Board and the Chair of the Governance Committee. If approved, once training has been completed successfully, educational expenses will be reimbursed. (See Expense Reimbursement policy).

COMMITTEES OF THE BOARD - POLICY

1. GENERAL PURPOSE AND SCOPE

This policy statement describes the terms of reference for standing committees and provides guidelines for Director performance and rotation on committees. Special committees of the Board may be constituted from time to time to review particular interests of the business.

In general, each Director is required to participate on a minimum of one standing committee, and a maximum of three, except the Chair who may participate in standing committees except the Finance Committee.

2. COMMITTEE POLICY

Committees are responsible for monitoring assigned areas and developing strategic policy and recommendations for the consideration of the Board as a whole. Committees only have the authority delegated to them by the Board. Committees should not be involved in the day-to-day operations or administration of the business – the Board and Committee focus is on governance and stewardship, rather than on management operations, which is executing strategy and managing day-to-day operations. In general, the role of committees is to:

- Assist the Board with strategy and policy development.
- Comment and provide advice on preliminary recommendations from management to the Board within the framework of Board-approved goals and policy statements.
- To make recommendations to the Board based on information and recommendations from management.

A. It is the policy of the Board of Directors that there are 2 standing committees, namely:
   a. Governance Committee
   b. Finance Committee

B. Committees will have a minimum of three members, none of whom shall be officers of the Corporation. The members of the Committee, who express interest, may be appointed at the meeting of the Board of Directors following the first Board Meeting in the new-year.

C. The schedule of meetings of each committee will be determined by its Chair, based upon the annual work plan designed to discharge the responsibilities of the committee as set out in its mandate. The Chair of the committee will develop the agenda for each committee meeting through consultation as appropriate with members of management, staff and the committee. Each committee will report to the Board on the results of each committee meeting by way of formal meeting minutes for ratification by the Board.

niagara peninsula energy inc.
Your Local Utility

BOARD of DIRECTORS ROLES & RESPONSIBILITIES & COMMITTEE TERMS OF REFERENCE

December 2019

CONTENTS: PAGE:

Role of the Board of Directors

The role of the Board is to provide stewardship of the organization and to add to the long-term success of the Corporation through attending to the following key items:

- interpret and oversee implementation of shareholder direction in conjunction with the best interests of the Corporation.
- optimize long-term shareholder value.
- earn a competitive profit compared to other like-sized utilities, and to ensure the Corporation avoids unacceptable risk.
- lead a business that is strong, resilient, sustainable, and competitive with challengers, actual and potential.
- add value to the Corporation by guiding its strategic management including setting out goals for management, as well as appointing, supporting, overseeing, and monitoring the best available senior management team.
- together with the President, create, adopt, and implement a strategic agenda and policy using a disciplined planning process. This agenda should periodically be updated and modified from business performance feedback and external environmental (business) scans.
- monitor the performance of the organization to ensure the success of the Corporation.
- report on the performance of the Corporation to the Shareholder.

As stated, the Board is responsible for the stewardship of the Company. This requires the Board to oversee the conduct of the business and affairs of the Company. The Board discharges some of its responsibilities directly and discharges others through committees of the Board. The Board is not responsible for the day-to-day management and operation of the Company's business, as this responsibility has been delegated to management.

Role of the Chair

The principal responsibilities of the Chair of the Board shall be to oversee, manage, and assist the Board in fulfilling its duties and responsibilities as a Board in an effective manner independently of management. The Chair shall be responsible, among other things,

- to chair Board meetings and annual and special meetings of the Corporation's shareholders;
- to organize an appropriate annual work plan and regularly scheduled meetings for the Board;
- to participate in the preparation of the agenda for each Board meeting;

- to monitor the work of the committees of the Board. Also, the Chair may attend, as a non-voting participant, all meetings of the Board committees, (in addition to those on which he/she otherwise sits);
- to arrange for an appropriate information package to be provided on a timely basis, no less than four working days, to each director in advance of the meeting;
- to assist in the Board's evaluation and self-assessment of its effectiveness and implementation of improvements;
- to provide appropriate guidance to individual Board members in discharging their duties;
- to ensure newly appointed directors receive an appropriate orientation and education program;
- to provide arrangements for members of the Board to communicate with the Chair formally and informally concerning matters of interest to Board members; and
- to promote best practices and high standards of corporate governance.
- monitor the annual Board calendar and processes including scheduling and context of meetings and agendas.
- facilitate the orientation for new Directors; periodically review and update content of the orientation ~~and~~ process in partnership with the CEO.
- establish, monitor, review, and recommend to the Board for approval the annual specific goals and objectives of the CEO and the attainment of the goals and objectives annually.
- to establish an adhoc committee to make the recommendation to the Board regarding succession planning of the CEO.

Role of the Vice Chair

The Vice Chair will facilitate the functioning of the Board independently of management of the Company, and provide independent leadership to the Board. The Vice Chair shall substitute for the Chair and serve as Chair if the Chair is not available.

Role of the Directors

There are general duties and responsibilities of individual directors in common law and in *The Canada Business Corporations Act* ("CBCA"),The Ontario Business Corporation Act ("OBCA") and the Corporation's by-laws.

The relationship of the director to the Corporation is a fiduciary one. A fiduciary relationship is defined as the relationship of one person to another, where the former is bound to exercise rights and powers in good faith for the benefit of the latter (eg. as between trustee and beneficiary). A 'fiduciary' is a person in a position of authority whom the law obligates to act solely on behalf of the person he or she represents and in good faith.

The Corporation directors are "trustees" in the sense that in performance of their duties, they stand in a fiduciary relationship to the Corporation and are bound by all of the rules of fairness, morality, and honesty that the law imposes. From this fiduciary role comes the stewardship responsibility to preserve and enhance shareholder value and as such, the Board serves as trustees of the investment of the shareholders.

Directors must individually, in connection with the powers and duties of their office, exercise the care, diligence, and skill that a reasonably prudent person would exercise in comparable circumstances.

Duties of Individual Directors

The duties of a director as established by the OBCA and as interpreted by the courts may be summarized as follows:

- duty of Honesty: In his or her dealings with fellow directors, a director must tell the whole truth and act in good faith. Secret profits are forbidden to directors;
- duty of Loyalty: A director is required to give individual loyalty to the Corporation. Each director must exercise his or her powers honestly and for the benefit of the Corporation as a whole;
- duty of Care: A director is required to exercise prudence and diligence. The duty of care requires prudence based on common sense;
- duty of Diligence: A director must make those inquiries which a person of ordinary care in his or her position or in managing his or her own affairs would make;
- duty of Skill: Every director is required to exercise the care, diligence, and skill that a reasonably prudent person would exercise in comparable circumstances; and

  Further detail regarding the above duties can be found in "Guidelines for Corporate Directors in Canada" published by the Institute of Corporate Directors.

The responsibilities set out below are meant to serve as a framework to guide individual directors in their participation on the Board, with a view to enabling the Board to carry out its mandate, duties, and responsibilities. These responsibilities include:

- assuming a stewardship role, and overseeing the business and affairs of the Corporation through the CEO;
- maintaining a clear understanding of the Corporation, including its strategic and financial plans and objectives, emerging trends and issues, significant initiatives, and capital allocations and expenditures, management risks, internal systems, processes and controls, program for compliance with applicable regulations, and governance, audit and accounting principles and practices;
- preparing for each Board and Committee meeting by reviewing materials and requesting, where appropriate, information that will allow the director to properly participate in the Board's deliberations, make informed business judgments, and exercise oversight;
- attending all Board and Committee meetings and actively participating in deliberations and decisions. When attendance is not possible, a director should nevertheless become familiar with the matters to be covered at such meetings;

- voting on all decisions of the Board or its Committees, except when a conflict of interest exists or may exist;
- preventing personal interests from conflicting with, or appearing to conflict with the interests of the Corporation, and disclosing details of such conflicting interests as they arise; and
- acting in the highest ethical manner and with integrity in all matters.

Director Risk Management Guidelines

Directors should:

- attend Board meetings faithfully, being absent only for compelling reasons;
- ask questions of management to gain reasonable assurance of information, due diligence on the part of management, and consistency with standards of the organization;
- record in writing any dissenting opinion;
- ensure that the Corporation's affairs are conducted according to its constitutional documents;
- keep abreast of the activities of the Corporation and be well-versed in the industry;
- be aware of the various statutes and regulations and the provisions pertaining to corporate offenses;
- refrain from voting on questions where their independence could be called into question;
- retain the right to advice from outside experts where warranted;
- ensure that there is follow-up on resolutions passed by the Board;
- obtain assurance of timely payment of employee wages, source deductions, income tax instalments, GST, PST; and
- ensure that the Corporation is in compliance with all environmental legislation, has an up-to-date environmental policy, and that management makes regular reports to the Board.

Role of the Secretary

The duties and functions of the Secretary include:

- schedules orientation, training and education for the Board of Directors;
- disseminates the "Notice" for regular, special, or in-camera Board meetings;
- prepares the Agenda and records the Minutes for Board and for Committee meetings as directed by the Board Chair or Committee Chair;
- creates Agenda materials, whether hard or soft copy, for Directors in preparation for meetings;
- advises the Chair on correct procedures and requirements for motions/resolutions;
- communicates decisions and matters requiring follow-up to the Board and to appropriate people on a need to know basis;

- ensures compliance with the By-laws or regulations governing the Board and the organization;
- develops and maintains a schedule of meetings and any outstanding obligations for the organization;
- drafts Minutes for approval by the Board Chair and any Committee Chair;
- maintains the Minute Books;
- organizes the Annual General Meeting (AGM);
- performs tasks at the request of and on behalf of the Board Chair and any Committee Chair.

Role of the Committee Chairs

The fundamental responsibility of the Chair of any committee of the Board of Directors is to be responsible for the management and effective performance of the committee, and provide leadership to the committee in fulfilling its mandate, and any other matters delegated to it by the Board.

The Chair of any committee of the Board of Directors will:

- chair committee meetings, and ensure that the committee is properly organized, and functions effectively;
- work with the Chairman of the Board, and Chief Executive Officer, and the Corporate Secretary, to establish the frequency of committee meetings, four per year or as required by the Chair and CEO, and the agendas for meetings;
- as appropriate and in consultation with the committee, retain, oversee, and terminate independent advisers to assist the committee, or its members in fulfillment of their responsibilities;
- report to the Board of Directors with respect to the activities of the committee and any recommendations deemed desirable by the committee;
- lead the committee in annually reviewing and assessing the adequacy of its mandate and evaluating its effectiveness in fulfilling its mandate.

Committees of the Board – Terms of Reference

COMMITTEE TERMS OF REFERENCE

Subject to the powers and duties of the Board, the Board assigns the mandate and terms of reference (ToR), for standing committees of the Board as follows:

a. Governance Committee

Purpose

The Governance Committee's primary role is to establish process and practices to enable the Board of Directors in delivering effective governance of the organization. This includes providing for governance practices to evolve with the needs of the organization and the expectations of the stakeholders. The Governance Committee is responsible for creating a framework to hold the Board accountable to the organization and its stakeholders. The Committee will also supervise the governance system of the organization to monitor that the duties of the governance body are being met and regulatory requirements are being fulfilled.

The objectives of the Committee are to assist the Board in fulfilling its oversight responsibilities and to hold directors and Board committees accountable to fulfilling their duties.

Membership and Quorum

The Governance Committee will be comprised of no less than four (4) members of the Board. A quorum for meetings will be three (3) members.

Chair

The Board of Directors shall appoint the Chair of the Governance Committee.

Authority

The Governance Committee fulfills its responsibilities on behalf of the Board and makes recommendations to the Board on policies relating to governance matters as well as structural changes to the Board or the bylaws of the organization. The Committee will have authority to approve processes to be used by the Board to put the governance policies into action.

Roles and Responsibilities

- monitor and consider trends in corporate governance generally as well as regulators' expectations for the Board and consider implications to the organization.
- monitor the effectiveness of the organization's governance practices and make/ recommend changes on an annual basis.

- annually consider Board committee structure, and ensure it is appropriate given the evolution of governance, structure and operations of the organization.
- annually review NPEI policies governing Board size, composition, and candidate criteria.
- ensure mandates are updated annually for: all Board committees, the Board itself, the directors, the Chair of the Board and for the Chairs of Committees; in particular review Committee mandates to ensure there is no overlap of duties and no gaps in duties between Committees.
- recommend to the Board the allocation of Directors to the Board committees. This should reflect the consideration of skill sets required by the committees, the interest of Directors, as well as a desire to rotate Directors around the committees. Rotation of Directors around committees will be complemented with the consideration of continuity and experience of committee membership.
- monitor Board Committees on the fulfillment of their mandates.
- review and make recommendations regarding remuneration for NPEI Directors, the expense reimbursement policy, and director education.
- review ongoing education sessions including such topics as regulatory, legal, and sector changes/issues.
- ensure the maintenance of a Director manual and updates to it annually.

Meetings

The Committee shall meet as required. The Committee shall determine its own procedures for the conduct of the meetings.

Reporting

Minutes of all meetings of the Governance Committee will be provided to the Board. The Chair may provide an oral report to the Board on matters not contained in the Minutes. Supporting schedules and information reviewed by the Committee will be available for examination by any Director upon request to the Corporate Secretary.

Resources

* Chief Executive Officer	*Secretary to the Board
* Other Management, as needed	*Outside advisors, as needed (legal counsel, consultants for Board assessment)

b. Finance Committee

Purpose

The Finance Committee's principal role is to ensure that due diligence is directed towards verifying that an effective risk management and control framework has been implemented by management. This framework is to provide reasonable assurance that the financial, operational and regulatory objectives of the Company are achieved and that the governance and accountability responsibilities of the Board and management are met.

The Finance Committee undertakes responsibility for the oversight of the design and implementation of internal controls to support the risk management framework, the integrity of financial reporting, and compliance with regulatory matters.

Objectives

The objectives of the Finance Committee are:

- to assist the Board to fulfill its oversight responsibilities, including accountable management of funds, efficiency and effectiveness of controls and safeguarding of assets;
- to gain assurance that the Company is in compliance with applicable laws, regulations and
  policies;
- to gain assurance that there is reliability in external financial reports;
- to provide for independence of the internal audit function;
- to communicate concerns of the Board to the external auditors and have input into the overall direction of all audit efforts;
- to engage external auditors and provide appropriate oversight of their work; and to
- to promote effective and timely resolution of audit issues.

Membership and Quorum

The Board appoints members of the Finance Committee. The Finance Committee will be comprised of not less than four (4) members of the Board. A quorum for any meeting will be three (3) members. At least one committee member must be literate with financial practices which can be demonstrated through past experience on a finance or audit committee and/or through business experience.

Chair

The Board of Directors shall appoint the Chair of the Finance Committee.

Authority

The Finance Committee fulfills its role on behalf of the Board of Directors and makes recommendations to the Board on policies and matters in the areas of financial reporting and internal controls.

It is empowered to:

- retain outside council, accountants, auditors, or others to advise the committee and determine compensation for such advisors subject to prudent stewardship of resources;
- seek any information it requires from employees and external parties and meet as necessary;
- ensure the external auditors is given notice of every meeting of the committee;
- through the Committee Chair, convene a committee meeting at the request of the auditor, an audit committee member or any director, to consider any accounting, internal control, or audit matter.

Roles and Responsibilities

The Finance Committee works towards obtaining assurance that the elements of control (resources, systems, processes, structure and tasks) are in place to support the enterprise risk framework for the Company. The Finance Committee:

- gains assurance that the Company's activities are managed within an appropriate framework of ethics and control;
- gains assurance that the Board has set necessary policies in compliance with applicable legal, regulatory and ethical requirements;
- reviews policies and procedures that safeguard the Company's assets;
- gains assurance that the internal auditors are not restricted or impeded in the conduct of their responsibility by other personnel of the Company;
- establishes procedures for confidential, anonymous submission by employees of the Company of concerns regarding questionable accounting or auditing matters;

Financial Reporting

The Finance Committee will provide oversight to the reporting of financial results as follows:

- reviews and approves accounting policies used for the Company's financial reporting including any significant changes from year to year;
- reviews management's methodology of determining provisions and adequacy thereof, where these provisions are reflected in the financial statements;

- gains assurance that an effective process is in place, including having appropriate internal controls, to provide reasonable assurance that financial reporting has integrity and provides for reliable and fairly presented financial statements;
- receives, reviews the annual financial audited financial statements and forwards to Board for approval;
- reviews reports containing financial information for external distribution and approves such before distribution;
- receives, reviews financial statements of material subsidiaries while respecting the role of the Board Committee of subsidiaries;
- receives reports from management regarding compliance with financial regulatory requirements and other legislative compliance.

Appendix 1-12

Current Tariff of Rates and Charges, effective May 1, 2020

Schedule A

To Decision and Rate Order

Tariff of Rates and Charges

OEB File No: EB-2019-0054

DATED: December 12, 2019

Niagara Peninsula Energy Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2020

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

EB-2019-0054

RESIDENTIAL SERVICE CLASSIFICATION

This class pertains to customers residing in detached, semi-detached or duplex dwelling units, where energy is supplied single-phase, 3 wire, 60 hertz, having a nominal voltage of 120/240 volts. Large residential services will include all services from 201 amp. Up to and including 400 amp., 120/240 volt, single phase, three wire. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	33.67
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Low Voltage Service Rate	$/kWh	0.0005
Rate Rider for Disposition of Global Adjustment Account (2020) - effective until June 30, 2020 Applicable only for Non-RPP Customers	$/kWh	0.0001
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until April 30, 2021	$/kWh	0.0012
Retail Transmission Rate - Network Service Rate	$/kWh	0.0074
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0054

MONTHLY RATES AND CHARGES - Regulatory Component

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

Niagara Peninsula Energy Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2020
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2019-0054

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This class pertains to non-residential customers taking electricity at 750 volts or less whose monthly average peak demand is less than, or forecast to be less than, 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor’s Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	40.15
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0146
Low Voltage Service Rate	$/kWh	0.0004
Rate Rider for Disposition of Global Adjustment Account (2020) - effective until June 30, 2020 Applicable only for Non-RPP Customers	$/kWh	0.0001
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until April 30, 2021	$/kWh	0.0012
Retail Transmission Rate - Network Service Rate	$/kWh	0.0067
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0047

MONTHLY RATES AND CHARGES - Regulatory Component

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

Niagara Peninsula Energy Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2020
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2019-0054

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or forecast to be equal to or greater than 50 kW but less than 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	109.12
Distribution Volumetric Rate	$/kW	3.5671
Low Voltage Service Rate	$/kW	0.1612
Rate Rider for Disposition of Global Adjustment Account (2020) - effective until June 30, 2020 Applicable only for Non-RPP Customers	$/kWh	0.0001
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until April 30, 2021 Applicable only for Non-Wholesale Market Participants	$/kW	0.0384
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until April 30, 2021	$/kW	0.4366
Retail Transmission Rate - Network Service Rate	$/kW	2.7628
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.9004

Niagara Peninsula Energy Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2020
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2019-0054

MONTHLY RATES AND CHARGES - Regulatory Component

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

Niagara Peninsula Energy Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2020

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

EB-2019-0054

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less whose average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electricity demand/consumption of the proposed unmetered load. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per customer)	$	20.73
Distribution Volumetric Rate	$/kWh	0.0144
Low Voltage Service Rate	$/kWh	0.0004
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until April 30, 2021	$/kWh	0.0012
Retail Transmission Rate - Network Service Rate	$/kWh	0.0067
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0047

MONTHLY RATES AND CHARGES - Regulatory Component

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

Niagara Peninsula Energy Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2020

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EB-2019-0054

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	18.03
Distribution Volumetric Rate	$/kW	22.4995
Low Voltage Service Rate	$/kW	0.1347
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until April 30, 2021	$/kW	0.4079
Retail Transmission Rate - Network Service Rate	$/kW	2.0455
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.5881

MONTHLY RATES AND CHARGES - Regulatory Component

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

Niagara Peninsula Energy Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2020
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EB-2019-0054

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. Street lighting profile is derived through the use of a “virtual street lighting meter” that uses a street light control eye, consistent with the model type and product manufacturer of devices currently in service in the Applicant’s distribution area, to simulate the exact daily conditions that the typical street light is exposed to. This simulated street light load is captured using an interval metering device, and is processed as part of the distributor’s daily interval meter interrogation, validation and processing procedures. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor’s Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	1.27
Distribution Volumetric Rate	$/kW	4.9783
Low Voltage Service Rate	$/kW	0.1239
Rate Rider for Disposition of Global Adjustment Account (2020) - effective until June 30, 2020 Applicable only for Non-RPP Customers	$/kWh	0.0001
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until April 30, 2021	$/kW	0.4317
Retail Transmission Rate - Network Service Rate	$/kW	2.0884
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.4600

MONTHLY RATES AND CHARGES - Regulatory Component

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

Niagara Peninsula Energy Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2020
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EB-2019-0054

microFIT SERVICE CLASSIFICATION

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

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

ALLOWANCES

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

Niagara Peninsula Energy Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2020

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EB-2019-0054

SPECIFIC SERVICE CHARGES

APPLICATION

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

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

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

Customer Administration		
Returned cheque (plus bank charges)	$	20.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account (see Note below)		
Late payment - per month (effective annual rate 19.56% per annum or 0.04896% compounded daily rate)	%	1.50
Reconnection at meter - during regular hours	$	65.00
Reconnection at meter - after regular hours	$	185.00
Reconnection at pole - during regular hours	$	185.00
Reconnection at pole - after regular hours	$	415.00
Other		
Service call - customer owned equipment	$	30.00
Service call - after regular hours	$	165.00
Temporary service install & remove - overhead - no transformer	$	500.00
Temporary service install & remove - underground - no transformer	$	300.00
Temporary service install & remove - overhead - with transformer	$	1,000.00
Specific charge for access to the power poles (with the exception of wireless attachments)	$	44.50

Niagara Peninsula Energy Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2020

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EB-2019-0054

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

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

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

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

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

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity		
One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	102.00
Monthly fixed charge, per retailer	$	40.80
Monthly variable charge, per customer, per retailer	$	1.02
Distributor-consolidated billing monthly charge, per customer, per retailer	$	0.61
Retailer-consolidated billing monthly credit, per customer, per retailer	$	(0.61)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.51
Processing fee, per request, applied to the requesting party	$	1.02
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	4.08
Notice of switch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019)	$	2.04

LOSS FACTORS

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

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0479
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0374

Appendix 1-13

Shareholders Agreement-January 1, 2008

SHAREHOLDERS AGREEMENT

Dated as of January 1, 2008

NIAGARA FALLS HYDRO HOLDING CORPORATION

-and-

PENINSULA WEST POWER INC.

-and-

NIAGARA PENINSULA ENERGY INC.

-and-

SUCH OTHER PERSONS AS MAY
BECOME SHAREHOLDERS IN NIAGARA PENINSULA ENERGY INC.

Borden Ladner Gervais LLP
Scotia Plaza, 40 King Street West
Toronto, Ontario
MSH3Y4

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SHAREHOLDERS AGREEMENT

THIS AGREEMENT made as of the **[1st day of January, 2008]**.

AMONG:

NIAGARA FALLS HYDRO HOLDING CORPORATION, a corporation duly incorporated under the *Business Corporations Act* (Ontario) (hereinafter referred to as **"NFHC"**)

- and -

PENINSULA WEST POWER INC., a corporation duly incorporated under the *Business Corporations Act* (Ontario) (hereinafter referred to as **"PWPI"**)

- and -

NIAGARA PENINSULA ENERGY INC., a corporation duly amalgamated under the *Business Corporations Act* (Ontario) (hereinafter referred to as the "**Corporation**")

- and -

SUCH OTHER PERSONS AS MAY FROM TIME TO TIME BECOME SHAREHOLDERS IN THE CORPORATION AND PARTIES HERETO

RECITALS:

A. NFHC was the sole shareholder of Niagara Falls Hydro Inc. ("**NFHI**") an electricity distribution company created pursuant to Section 142 of the *Electricity Act, 1998* (Ontario) (the "**Electricity Act**");

B. PWPI was the sole shareholder of Peninsula West Utilities Limited ("**PWUL**") an electricity distribution company created pursuant to Section 142 of the Electricity Act;

C. NFHC is wholly-owned by Niagara Falls;

D. PWPI is owned by Lincoln, Pelham and West Lincoln;

E. NFHC and PWPI agreed to amalgamate NFHI and PWUL to form the Corporation (the "**Amalgamation**") pursuant to the terms of the Merger Agreement dated **[December 31, 2007]** among NFHC, NFHI, PWPI and PWUL (the "**Merger Agreement**") and the Amalgamation Agreement among NFHC, NFHI, PWPI and PWUL dated **[December 31, 2007]** and the Amalgamation was effective **[January 1, 2008]**;

F. Upon the Amalgamation, NFHC received seven hundred and forty-five (745) common shares in exchange for one hundred (100) common shares in the capital of

NFHI and PWPI received two hundred and fifty-five (255) common shares in exchange for one hundred (100) common shares in the capital of PWUL;

G. The Councils of Lincoln, Pelham and Niagara Falls approved the Amalgamation. The Council of West Lincoln did not approve the Amalgamation.

H. The shareholder agreement of PWPI requires two-thirds (2/3) of the votes cast at a duly constituted meeting of the shareholders of PWPI to approve all shareholder decisions, including amalgamations. With the approval of Lincoln and Pelham, which collectively own 76% of the voting shares of PWPI, at a duly constituted shareholders meeting, the shareholders of PWPI approved the Amalgamation. PWPI, the sole shareholder of PWUL, approved the Amalgamation. The directors of both PWPI and PWUL approved the Amalgamation.

I. The shareholders and directors of NFHC and NFHI approved the Amalgamation.

J. The authorized capital of the Corporation consists of an unlimited number of common hsares of which 1,000 are issued and outstanding.

K. At the date hereof all of the issued and outstanding shares of the Corporation are registered and beneficially owned as follows:

Shareholder	**Corporation Shares**
NFHC	745 common shares
PWPI	255 common shares

L. The parties have agreed to set out in this Agreement their respective rights and obligations with respect to the management and operation of the Corporation and the ownership of shares in the Corporation and with respect to their relationship towards each other; and

M. The operation and management of the Corporation shall be based upon the general objectives and business principles set out in Section 2.1 of this Agreement.

NOW, THEREFORE IN CONSIDERATION OF THE FOREGOING AND OF THE MUTUAL COVENANTS HEREIN CONTAINED, THE PARTIES HERETO AGREE AS FOLLOWS:

ARTICLE 1 - INTERPRETATION

1.1 **Definitions:** Whenever used in this agreement unless there is something in the subject matter or context inconsistent therewith, the following terms shall have these respective meanings:

"**Additional Shareholders**" means such Persons, other than NFHC or PWPI, as may from time to time become shareholders of the Corporation and parties to this Agreement.

"**Affiliate Relationships Code**" means the Affiliate Relationships Code for Electricity Distributors and Transmitters issued by the OEB, as amended from time to time and any replacement code or directive.

"**Agreement**" means this Shareholders Agreement, and includes any agreement which is supplementary to or an amendment or confirmation of this Agreement (and which is entered into in accordance with this Agreement) and any schedules hereto or thereto.

"**Amalgamation**" has the meaning set forth in the Recitals to this Agreement.

"**Applicable Law**" means, collectively, all applicable federal, provincial and municipal laws, statutes, ordinances, decrees, rules, regulations, by-laws, legally enforceable policies, codes, or guidelines, judicial, arbitral, administrative, ministerial, departmental or regulatory judgments, orders, decisions, directives, rulings or awards, and conditions of any grant of approval, permission, certification, consent, registration, authority or licence by any statutory body, self-regulatory authority or other Governmental Authority.

"**Articles**" means the articles of amalgamation of the Corporation in effect on the date hereof.

"**Board**" means the board of directors of the Corporation as elected by the Shareholders from time to time in accordance with the provisions of this Agreement.

"**Business**" means, with respect to the Corporation, the distribution of electricity to the customers of the Corporation and the provision of such ancillary services as may be determined from time to time and such other businesses which may be permitted to be undertaken by the Corporation pursuant to Section 2.3 of this Agreement.

"**Business Day**" means any day except Saturday, Sunday or any day which is a statutory holiday in the Province of Ontario.

"**Chair**" means the director who is appointed chair of the Board from time to time as provided in this Agreement.

"**Council**" means the municipal Council at such time of the Municipalities or of any other municipality which may become a direct or indirect shareholder of the Corporation from time to time.

"**Electricity Act**" means the *Electricity Act, 1998* (Ontario), as amended from time to time and any replacement or successor legislation.

"**Former Director**" has the meaning set forth in Section 4.13.

"**Governmental Authority**" means any government or political subdivision (including without limitation, any municipality or federal or provincial ministry) or quasi-governmental or regulatory agency, authority, board, commission, department or instrumentality of any government or political subdivision, or any court or tribunal including the IESO, OEB and OPA.

"**IESO**" means the Ontario Independent Electricity System Operator and any successor.

"**includes**" means "includes, without limitation" and "including" means "including, without limitation".

"**Information**" has the meaning set forth in Section 14.3.

"**LDC**" means an electricity distribution corporation created pursuant to Section 142 of the Electricity Act and licensed to distribute electricity pursuant to the OEB Act.

"**Lincoln**" means the Town of Lincoln.

"**Municipalities**" means Lincoln, Niagara Falls, Pelham and West Lincoln;

"**Niagara Falls**" means the City of Niagara Falls.

"**Non-Selling Shareholder**" has the meaning set forth in Section 13.5(a).

"**OBCA**" means the *Business Corporations Act* (Ontario), as amended from time to time.

"**OEB**" means the Ontario Energy Board and any successor.

"**OEB Act**" means the *Ontario Energy Board Act*, *1998*, as amended from time to time and any replacement or successor or legislation.

"**Offered Shares**" has the meaning set forth in Section 8.1(a).

"**OPA**" means the Ontario Power Authority and any successor.

"**Ordinary Course of Business**" means the conduct of the Business in the ordinary and usual course and in a manner consistent with the manner in which the Business is carried on as of the date hereof or as may be permitted pursuant to Section 2.3 hereof including as to the nature and scope of the Business and shall include the acquisition of the shares, assets or business of

LDC's and related businesses and the amalgamation of the Corporation with other LDC's.

"**Parties**" means the Shareholders and the Corporation and "Party" means any one of them.

"**Pelham**" means the Town of Pelham.

"**Permitted Transferee**" has the meaning set forth in Section 7.3(a).

"**Person**" means any individual, corporation, partnership, firm, joint venture, syndicate, association, trust, Governmental Authority and any other form of entity or organization.

"**Pro Rata**" means in the same proportion that the number of common shares owned by a Shareholder is to all of the then issued and outstanding common shares of all Shareholders of the Corporation.

"**Prospective Purchaser**" has the meaning set forth in Section 8.3.

"**Purchase Notice**" has the meaning set forth in Section 8.2.

"**Purchase Price**" has the meaning set forth in Section 8.1(a).

"**Right of First Refusal Period**" has the meaning set forth in Section 8.2.

"**Remaining Shareholders**" has the meaning set forth term in Section 8.1(b).

"**Sale Notice**" has the meaning set forth in Section 8.1(a).

"**Selling Shareholder**" has the meaning set forth in Section 8.1(a).

"**Shareholder**" means individually any, and "**Shareholders**" means collectively all, of NFHC and PWPI and any Person to whom any Shares are transferred, or issued, in accordance with the terms of this Agreement, at any time subsequent to the date of this Agreement.

"**Shares**" means common shares of the Corporation.

"**Share Purchase Price**" has the meaning set forth in Section 12.3.

"**Special Resolution**" means a resolution that is submitted to a meeting of the Shareholders called for the purpose of considering the resolution and passed, with or without amendment, at the meeting by at least two-thirds (2/3) of the votes cast.

"**Standstill Period**" means the five (5) year period from the date of this Agreement to and including **[January 1, 2013]**.

"**West Lincoln**" means the Township of West Lincoln.

"**Withdrawal Date**" has the meaning set forth in Section 12.4.

"**Withdrawing Shareholder**" has the meaning set forth in Section 12.2.

1.2 **Interpretation:** Unless otherwise defined in this Agreement, words and phrases that have not been defined shall have the meaning ascribed to them in the OBCA.

1.3 **Interpretation Not Affected by Headings:** The division of this Agreement into Articles, Sections, Subsections, Paragraphs, Subparagraphs and Clauses and the insertion of headings are for the convenience of reference only and shall not affect the construction or interpretation of this Agreement. The terms "this Agreement", "hereof", "herein", "hereunder" and similar expressions refer to this Agreement and not to any particular Article, Section, Subsection, Paragraph, Subparagraph or Clause or other portion hereof and include any agreement or instrument supplemental or ancillary hereto. Unless something in the subject matter or context is inconsistent therewith, references herein to Articles and Sections are to Articles and Sections of this Agreement.

1.4 **Number and Gender:** Words importing the singular number only shall include the plural and vice versa, words importing the masculine gender shall include the feminine and neuter genders and vice versa.

1.5 **Accounting Principles:** Wherever in this Agreement reference is made to generally accepted accounting principles, such reference shall be deemed to be the generally accepted accounting principles from time to time approved by the Canadian Institute of Chartered Accountants, or any successor institute, applicable as at the date on which such calculation is made or required to be made in accordance with generally accepted accounting principles.

1.6 **Effect of this Agreement:** To the extent that this Agreement specifies that any matters relating to the Corporation may only be or shall be dealt with or approved by, or shall require action by the Shareholders, the discretion and powers of the directors of the Corporation to manage and to supervise the management of the business and affairs of the Corporation with respect to such matters are correspondingly restricted. For greater certainty, the Parties agree that Sections 5.1 and 5.2 of this Agreement are intended to operate as a unanimous shareholders agreement with respect to the Corporation, within the provisions of Section 108(2) of the OBCA.

1.7 **Statutes and Amendments:** Any reference in this Agreement to an agreement, or to a statute, regulation or rule promulgated under a statute or to any provision of an agreement, a statute, regulation or rule shall be a reference to the agreement, statute, regulation, rule or provision, as amended, restated, re-enacted or replaced from time to time.

1.8 **Schedules:** The following schedules are incorporated herein and form part of this Agreement:

Schedule A Valuation Method

ARTICLE 2 - OBJECTIVES, GUIDING PRINCIPLES AND PERMITTED BUSINESS ACTIVITIES

2.1 **Guiding Principles and Objectives:** The Parties acknowledge and recognize the following guiding principles and objectives of the Corporation and the intention of the Shareholders that the Corporation be managed in a manner consistent with these guiding principles and objectives:

(a) maintain local presence and control over the management of electricity services and rates;

(b) improve electricity distribution services to local customers;

(c) improve the utilization of existing resources;

(d) explore business options that achieve new economics of scale and avoid duplication of services and costs to the customer;

(e) pursue strategic partnerships that contribute to a strengthened corporate presence and voice – locally and provincially;

(f) improve corporate flexibility to better respond to emerging business opportunities and complexities in the electricity market; and

(g) increase corporation value to maximize Shareholder wealth.

2.2 **Financial Policies, Risk Management and Strategic Plan:** The Shareholders expect that the Board will establish policies to:

(a) Capital Structure - develop and maintain a prudent financial and capitalization structure for the Corporation consistent with industry norms and sound financial principles and established on the basis that the Corporation is a self-financing entity;

(b) Distribution Rates – ensure the establishment of just and reasonable electricity distribution rates for the regulated electricity distribution business of the Corporation which are:

(i) consistent with similar utilities in comparable growth areas and as may be permitted under the OEB Act;

(ii) intended to enhance the value of the Corporation; and

(iii) consistent with the encouragement of economic development and activity for each of the Shareholders.

It is the intention of the parties to harmonize the distribution rates of NFHI and PWUL conditional on receiving all necessary regulatory approvals;

(c) Dividends – the establishment of a dividend policy, consistent with prudent financial practices, for the Corporation, all with the intention of providing the Shareholders with a reasonable rate of return on their investment while maintaining reasonable rates for customers;

(d) Risk Management - manage all risks related to the Business conducted by the Corporation through the adoption of appropriate risk management strategies and internal controls consistent with industry norms; and

(e) Strategic Plan - develop a long range strategic plan for the Corporation which is consistent with:

(i) the guiding principles and objectives in Section 2.1;

(ii) the maintenance of a viable Business; and preservation of the value of the Business for the Shareholders.

2.3 **Permitted Business Activities:**

The Corporation may engage in the business activities which are permitted by Applicable Law from time to time, including the Electricity Act and OEB Act and as the Board may authorize. In so doing, the Corporation shall conform to all requirements of the OEB, the IESO, the OPA and all other applicable Governmental Authorities.

ARTICLE 3 - IMPLEMENTATION OF THIS AGREEMENT

3.1 **Carrying out of the Agreement:**

(a) The Shareholders shall at all times act and vote their Shares to carry out and cause the Corporation to carry out the provisions of this Agreement.

(b) To the extent that each Shareholder is permitted by Applicable Law to bind its nominees to do so, the nominee directors of the Shareholder will act and vote as directors in order that the purpose, intent and provisions of this Agreement shall be carried out.

(c) The Corporation confirms its knowledge of this Agreement and will carry out and be bound by the provisions of this Agreement to the full extent that it has the capacity and power at law to do so.

3.2 **Endorsement on Share Certificates:** Share Certificates of the Corporation shall bear the following language either as an endorsement or on the face thereof:

> "The shares represented by this certificate are subject to all the terms and conditions of an agreement made as of **[January 1, 2008]**, a copy of which is on file at the registered office of the Corporation."

ARTICLE 4 - DIRECTORS AND OFFICERS

4.1 **Number of Directors:**

(a) The Articles of the Corporation shall provide for the Board to consist of a minimum of four (4) directors and a maximum of twelve (12) directors.

(b) The initial Board shall consist of eight (8) directors.

4.2 **Nomination of the Initial Directors:** Subject to Sections 4.4, 4.6 and 4.8 , NFHC shall be entitled to nominate four (4) directors and PWPI shall be entitled to nominate four (4) directors and thereafter each of NFHC and PWPI shall be entitled to nominate an equal number of directors. Directors shall hold office until such time as their successors are elected by the Shareholders.

4.3 **Election of Directors:** The Shareholders shall at all times act and vote their Shares to elect as directors of the Corporation the individuals nominated as directors by each Shareholder, and, if required by a Shareholder, to remove such director(s). The Shareholders shall at all times act and vote their Shares to maintain the equal representation of both NFHC and PWPI on the Board.

4.4 **Changing the Number of Directors:** In the event that the Shareholders desire to increase or decrease the number of directors serving on the Board, the Shareholders shall elect such directors, as determined by the Shareholders, in order to maintain the equal representation of both NFHC and PWPI on the Board.

4.5 **Qualification of Directors:**

(a) In addition to the requirements of the OBCA, the qualifications of candidates for the Board shall, where possible, include the following:

(i) commercial experience, sensitivity and acumen;

(ii) time availability;

(iii) corporate finance; accounting experience;

(iv) corporate governance experience;

(v) market development experience;

(vi) industry knowledge including, but not limited to, knowledge of competitive energy or telecommunications markets;

(vii) independent, objective and sound of judgment;

(viii) personal integrity and honesty;

(ix) knowledge of public policy and government regulation issues relating to the Corporation and the electricity industry;

(x) knowledge and experience concerning environmental matters, labour relations and occupational health and safety issues;

(xi) knowledge of the local communities;

(xii) awareness of public policy issues related to the Corporation;

(xiii) business expertise, including marketing, product development, mergers and acquisitions and/or retail experience;

(xiv) experience on boards of significant commercial corporations, preferably with revenues of $10 million annually or more; and

(xv) knowledge and experience with risk management strategy.

(b) Preference may be given to qualified candidates for the Board who are residents of the Municipalities; however, non-residents of the Municipalities shall not be excluded from serving as members of the Board.

4.6 **Affiliate Relationships Code:** The composition of the Board shall comply with the provisions of the Affiliate Relationships Code, as applicable, unless an exemption from compliance applicable to the Corporation has been provided by the OEB and is in effect.

4.7 **Chair:** The Chair shall be selected by the Board from among the directors and shall preside at each meeting of the Board. In the absence of the Chair, the chairman of the meeting shall be selected by the directors in attendance at such meeting.

4.8 **Term of Directors:**

(a) Each director of the Corporation shall be appointed for a term which may be from one (1) to three (3) years as provided in the by-laws of the Corporation.

(b) A director may be appointed for successive terms in the discretion of the Shareholder appointing such director.

4.9 **Removal of Directors:** Section 122 of the OBCA does not apply to the removal of directors from the Board. Each Shareholder shall be entitled in its discretion to cause any of the directors nominated by it to be removed and to nominate and have an individual elect a successor or successors, as the case may be, by providing a direction in writing to the Corporation and to the other Shareholders who shall elect such replacement director or directors. Upon the resignation or removal of a director from the Board, the Shareholder that nominated such director shall use reasonable efforts to obtain and deliver to the Corporation a resignation and release from such director in a form satisfactory to the Corporation.

4.10 **Voting:**

(a) All matters to be determined by the Board shall be determined by a majority vote of directors at a duly convened meeting of the Board and, in case of an equality of votes, the matter shall not be approved and the chairman of the meeting shall not be entitled to a second or casting vote.

(b) Notwithstanding Section 4.10(a) above, in lieu of a meeting of the directors, the consent of the directors with respect to any matter may be evidenced by a resolution in writing (which may be in counterparts) signed by all of the directors.

4.11 **Meeting of Directors:**

(a) The Board shall meet at least once each financial quarter at a time and place to be determined by the Chair. Additional meetings of the Board may be called by the Chair or any other director by notice in writing to every other director of the time, place and purpose of the meeting of the Board and the matters to be considered.

(b) All meetings of the Board shall, unless held by telephone or video conference, be held within the Province of Ontario.

(c) Any one or more of the directors may participate in a meeting of the Board by any telephonic or video device which permits all participants in the meeting to communicate with each other simultaneously and instantaneously, and such participation shall be deemed to constitute attendance at the meeting of the Board for the purpose of this Section 4.11. The Chair may determine that any meeting of the Board may be held by telephone or video conference.

(d) At least seven (7) Business Days prior to each meeting, each director shall be notified in writing of the time, place and purpose of the meeting of the Board and the matters to be considered.

(e) A director may waive notice of any meeting of the Board by an instrument in writing delivered to the Secretary of the Corporation.

4.12 **Quorum – Meetings of Directors**

(a) A quorum for a meeting of the Board shall consist of a majority of the total number of elected directors, (rounded up to the next whole number) provided that, so long as NFHC and PWPI are the only Shareholders of the

Corporation, at least one (1) director who is a nominee of NFHC and at least one (1) director who is a nominee of PWPI must be present at all meetings of the Board.

(b) If a quorum of directors is not present within thirty (30) minutes after the time appointed for a meeting of the Board, the meeting shall be adjourned to a date not less than five (5) and not more than fifteen (15) Business Days subsequent to the date originally set for the meeting, as the directors present at the meeting may determine.

(c) At least two (2) Business Days prior written notice shall be provided to all of the directors of the date for the meeting adjourned pursuant to Section 4.12(b).

(d) If a quorum is not present at such adjourned meeting, the Secretary of the Corporation shall forthwith call a further adjourned meeting of the Board, to be held not later than five (5) Business Days after the previously adjourned meeting was to be held and shall provide at least two (2) Business Days prior written notice thereof to the Shareholders. The Shareholders shall cause their respective nominee directors to attend, (or shall remove their nominee directors and nominate directors to be elected as replacement directors in accordance with Section 4.9 and cause such replacement directors to attend), the further adjourned meeting.

4.13 **Vacancies:** In the event of any vacancy occurring on the Board by reason of the death, disqualification, inability to act or resignation of any director (the "**Former Director**"), the Shareholder entitled to nominate the Former Director shall nominate another individual to replace the Former Director in order to fill such vacancy as soon as reasonably possible, and the Shareholders shall vote their Shares to elect such nominee accordingly.

4.14 **Insurance:** The Corporation shall acquire and maintain insurance coverage for the directors and officers of the Corporation as the Board may determine from time to time. In the event that such insurance coverage ceases to be available to the directors for any reason, each Shareholder shall be responsible for insuring its own nominees.

4.15 **Auditor:** Crawford, Smith, and Swallow shall be appointed as the initial auditor of the Corporation and shall hold office until such time as the Shareholders select a replacement.

4.16 **Corporate Governance Matters:** Subject to the provisions of Article 5, the Board shall supervise the management of the business and affairs of the Corporation and, in so doing, shall act honestly and in good faith with a view to the best interests of the Corporation and each director shall exercise the same degree of care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances.

4.17 **Initial Senior Executive Arrangements:**

(a) The Parties acknowledge and agree Brian Wilkie shall be the initial President and Chief Executive Officer of the Corporation.

(b) In addition to the senior executive arrangements provided in Section 4.17(a) the Board shall appoint such other officers of the Corporation as the Board may determine.

ARTICLE 5 - APPROVAL OF CERTAIN CORPORATE ACTIONS

5.1 **Unanimous Approval by Shareholders:** Subject to Section 5.3, unless first approved by an unanimous resolution of Shareholders, either adopted at a meeting of the Shareholders called for that purpose or evidenced by a resolution in writing signed by all of the Shareholders, no action shall be taken by the Corporation with respect to any of the following matters:

(a) Amalgamating, consolidating, reorganizing or merging the Corporation with another entity;

(b) Create new classes of shares;

(c) Issue, or enter into any agreement to issue, any shares of any class, or any securities convertible into any shares of any class, of the Corporation or grant any option or other right to purchase any shares or securities convertible into such shares;

(d) Amend the rights, restrictions or privileges of any Shares of the Corporation;

(e) Disposing of or encumbering all or substantially all of the assets of the Corporation;

(f) Changing the dividend policy for the Corporation;

(g) Any amendment to the provisions of this Agreement regarding proportional representation of the Shareholders on the Board or the rights of Shareholders to nominate members of the Board;

(h) Entering into any partnership, joint venture or other business venture that would involve the expenditure or investments of funds by the Corporation outside of the Ordinary Course of Business or that would change the status of the Corporation for taxation purposes, under the Electricity Act or the *Income Tax Act* (Canada), *Corporations Tax Act* (Ontario) or other Applicable Law;

(i) Changing the capitalization policy or the financing policy for the Corporation;

(j) Acquire any electricity distribution business outside of the municipal boundaries of the Municipalities or otherwise acquiring shares in another corporation;

(k) Making loans or providing financial support to a Shareholder, an employee or a person not at arm's length to a Shareholder; or

(l) Any amendment, assignment or termination of any agreement among the Corporation, Niagara Power Inc., Niagara West Transformation Corporation ("**NWTC**"), and/or PWPI regarding the administration and operation of NWTC and its transformation station.

5.2 **Special Resolution by Shareholders:** Subject to Section 5.3, unless first approved by a Special Resolution of the Shareholders, adopted at a meeting of the Shareholders called for that purpose, no action shall be taken by the Corporation with respect to any of the following matters:

(a) Change the name of the Corporation;

(b) Add, remove or change restrictions on the business of the Corporation;

(c) Amendment of articles or bylaws of the Corporation;

(d) Subject to Section 5.1(g) above regarding proportional representation on the Board, any change in the number of directors of the Corporation;

(e) Redeem, purchase for cancellation or otherwise retire any outstanding shares of the Corporation;

(f) Taking any action to wind-up or dissolve the Corporation;

(g) Taking any bankruptcy or insolvency related actions with respect to the Corporation;

(h) Apply to continue as a corporation in another jurisdiction;

(i) Incurring single project capital expenditures greater than $5 million;

(j) Creating a subsidiary of the Corporation;

(k) Borrowing of money in excess of $5 million;

(l) Becoming contingently liable for the debts or obligations of another person;

(m) Changing the fiscal year end of the Corporation;

(n) Changing the auditors of the Corporation;

(o) Giving security on the Corporation assets except in the ordinary course of business; or

(p) Change in the location of the head office of the Corporation.

5.3 **Additional Shareholders:** In the event that Persons become Shareholders of the Corporation in addition to NFHC and PWPI other than in accordance with Articles 7, 8, 9, 10, 11 and 12 of this Agreement, the parties acknowledge that provisions of this Agreement shall be reviewed and, if required, revised in a manner to be determined by the parties consistent with the guiding principles of the Corporation as described in Section 2.1 of this Agreement.

ARTICLE 6 - REPRESENTATIONS AND WARRANTIES

6.1 **Representations and Warranties by Shareholders.** Each Shareholder represents and warrants to each of the other Shareholders and acknowledges that each of the other Shareholders is relying on these representations and warranties in connection with entering into this Agreement:

(a) that each Shareholder owns beneficially and of record the number of issued and outstanding Shares which is set out opposite its name in Recital E to this Agreement, that those Shares are not subject to any mortgage, hypothec, lien, charge, priority, pledge, encumbrance, security interest or adverse claim, and that no Person has any rights to become a holder or possessor of any of those Shares or of the certificates representing them;

(b) that it is duly incorporated and validly existing under the laws of its jurisdiction of incorporation and that it has the corporate power and capacity to own its assets and to enter into and perform its obligations under this Agreement;

(c) that this Agreement has been duly authorized, executed and delivered by it, and (assuming due execution and delivery by the other Parties) is a legal, valid and binding obligation of it enforceable against it in accordance with its terms;

(d) that the execution, delivery and performance of this Agreement does not and will not contravene the provisions of its articles, by-laws, constating documents or other organizational documents, or the provisions of any contract, agreement or other instrument to which it is a party or by which it may be bound;

(e) that the Shareholder is not a non-resident for purposes of the *Income Tax Act* (Canada); and

(f) that all of the representations and warranties set out in Section 6.1(a) through (f) will continue to be true and correct during the term of this Agreement.

ARTICLE 7 - RESTRICTIONS ON SHARE TRANSFERS

7.1 **Standstill Period - Restricted Sales of Shares:** No Shareholder may sell all or any portion of its Shares without the prior written consent of all of the other Shareholders during the Standstill Period. After the Standstill Period has expired, a Shareholder may only sell, transfer, assign or otherwise dispose of the whole or any part of its Shares in accordance with this Agreement.

7.2 **Agreement Binding on Transferees:** No Shares of the Corporation shall be effectively issued, sold, assigned, transferred, disposed of or conveyed, by a Shareholder to any Person except in accordance with this Agreement and until the proposed transferee or purchaser executes and delivers to the Parties hereto an agreement to the same effect as this Agreement and any further agreement with respect to the Corporation to which the Shareholders are then, or are then required to be, a party. Upon the proposed transferee or purchaser so doing, such agreements shall enure to the benefit of and be binding upon all of the Parties to them as if all had executed and delivered the same agreements at the same time.

7.3 **Permitted Transferees:**

(a) Subject to the restrictions on transfer or sale in Section 7.1 and 7.2 hereof, a Shareholder may, without the consent of the other Shareholders, transfer any or all of the Shares owned by it to any Person (hereinafter in this Section 7.3 referred to as a "**Permitted Transferee**") provided that the Permitted Transferee is wholly-owned by such Shareholder or, if such Shareholder is a corporation, the Permitted Transferee is wholly-owned by the Controlling Shareholder of such Shareholder and provided that prior to any such transfer:

(i) the Permitted Transferee shall undertake in writing, by signing a counterpart of this Agreement, to be bound by the terms and conditions of this Agreement; and

(ii) the Controlling Shareholder of such Permitted Transferee represents, warrants, and undertakes in writing that it shall wholly own such Permitted Transferee for as long as such Permitted Transferee holds Shares of the Corporation.

(b) In the event that the transferee of the Shares ceases to be a Permitted Transferee for the purposes of this Section 7.3 then the Shares shall be promptly transferred back to the Shareholder.

7.4 **Pre-emptive Right**:.

(a) Except as expressly provided in this Agreement, if any additional Shares or other securities of the Corporation are approved for issue or if any other options or rights to purchase or subscribe for securities of the Corporation are approved for grant none of those Shares or other securities of the Corporation shall be issued by the Corporation, and none of those options or other rights shall be granted, at any time after the date of this Agreement, except in compliance with this Section 7.4.

(b) If the Corporation proposes to issue any Shares or other securities of the Corporation (in this Section 7.4, the "**Affected Securities**"), the Corporation shall give notice (an "**Issue Notice**") to the Shareholders of the proposed issuance. The Issue Notice shall constitute an offer for subscription by each of the Shareholders of that number of the Affected Securities (in this Section 7.4, its "**Proportionate Entitlement**") which bear the same relationship to the total number of Affected Securities as the number of issued and outstanding Shares held by each such Shareholder bears to the total number of issued and outstanding Shares (as reflected on the securities registers of the Corporation) at the date of the Issue Notices (in this Section 7.4, the "**Notice Date** ") at the subscription price determined by the Board for all those Affected Securities. Each Issue Notice shall:

(i) be made in writing by the Secretary and be made concurrently to all Shareholders in the same manner (whether by delivery, prepaid courier service or facsimile);

(ii) contain a description of the terms and conditions relating to the Affected Securities, the price at which the Affected Securities are offered and the date on which the purchase of the Affected Securities by the Shareholders is to be completed; and

(iii) state that any Shareholder that wishes to subscribe for less than its Proportionate Entitlement shall, in its notice of subscription, specify the number of Affected Securities (up to its Proportionate Entitlement) that it wishes to subscribe for.

The offer constituted by each Issue Notice shall be irrevocable and shall remain open for acceptance by the Shareholders for a period of thirty (30) days after the Notice Date.

(c) Each of the Shareholders shall have the right, exercisable by notice given to the Corporation within the period during which the offer constituted by the Issue Notice is open for acceptance under Section 7.4(b), to accept the offer constituted by the Issue Notice to subscribe for its Proportionate Entitlement of the Affected Securities or, if it wishes to subscribe for less than its Proportionate Entitlement, to indicate how many Affected Securities (up to its Proportionate Entitlement) it wishes to subscribe for. If no notice is given by a Shareholder under this Section 7.4(c), that Shareholder shall be deemed to have rejected the offer made available to it to subscribe for Affected Securities.

(d) If any of the Shareholders does not agree to purchase all of its Proportionate Entitlement of the Affected Securities or is deemed to have rejected the offer made available to it to subscribe for Affected Securities (in this Section 7.4, a

"**Declining Offeree**"), the Corporation shall forthwith so notify in writing (in this Section 7.4, the "**Additional Notice**") each of the other Shareholders which has accepted the offer to subscribe for not less than its Proportionate Entitlement of the Affected Securities (in this Section 7.4, a "**Purchasing Shareholder**"). Each of the Purchasing Shareholders shall have the right to subscribe for that number or any part thereof, of the Affected Securities that have not been accepted for subscription by the Declining Offerees (the "**Unsubscribed Securities**") which bears the same relationship to the total number of Unsubscribed Securities as the number of Shares held by each such Purchasing Shareholder bears to the total number of Shares by all Purchasing Shareholders (as reflected on the securities registers of the Corporation) at the date of the Additional Notice. Any Purchasing Shareholder that receives an Additional Notice shall have the right, exercisable by notice given to the Corporation within a period of ten (10) days after deemed receipt of that Additional Notice pursuant to Section 15.1, to agree that it will purchase the number of Unsubscribed Securities which it is entitled to purchase or any lesser number thereof specified by it in that notice. If no notice is given by a Purchasing Shareholder under this Section 7.4 within that ten (10) day period, that Purchasing Shareholder shall be deemed to have rejected the offer made available to it to purchase any Unsubscribed Securities. No Shareholder shall be obliged to purchase any Affected Securities in excess of the number indicated in its subscription.

(e) If any Affected Securities of any issue are not subscribed for prior to the expiry of the last applicable period pursuant to Sections 7.4(c) and 7.4(d), the Corporation may offer those unsubscribed for Affected Securities within a period of ninety (90) days after the expiration of the last applicable period pursuant to Sections 7.4(c) and 7.4(d) to any Person, but the price at which those Affected Securities may be issued shall not be less than the subscription price offered to the Shareholders and the terms of payment for those unsubscribed for Affected Securities shall not be more favourable to that Person than the terms of payment offered to the Shareholders.

(f) If the Corporation proposes to grant an option or other right for the purchase of or subscription for Affected Securities, that option or other right shall also be made available to Shareholders in accordance with Sections 7.4(b) through 7.4(e).

(g) The Corporation shall be entitled to issue additional Shares without complying with the provisions of this Section 7.4 when those Shares are being issued on the exercise of existing options or rights to purchase or subscribe for Shares.

ARTICLE 8 - RIGHT OF FIRST REFUSAL

8.1 First Right of Refusal:

(a) Any Shareholder (hereinafter in this Article 8 referred to as the "**Selling Shareholder**") who desires to transfer or sell all, but not less than all, of its Shares (hereinafter in this Article 8 referred to as the "**Offered Shares**") shall give notice of such proposed sale (hereinafter in this Article 8 referred to as the "**Sale Notice**") to the Corporation and to the other Shareholders and shall set out in the Sale Notice the terms upon which and the price at which it desires to sell the Offered Shares (such price being hereinafter in this Article 8 referred to as the "**Purchase Price**"). A Shareholder selling Shares under this Section 8.1 must sell all, and not less than all, of its Offered Shares, unless the other Shareholders otherwise agree.

(b) Upon the Sale Notice being given, the other Shareholders (hereinafter in this Article 8 referred to as the "**Remaining Shareholders**") shall have the right to purchase all, but not less than all, of the Offered Shares for the Purchase Price on a Pro Rata basis as described in Section 8.2.

8.2 **Exercise of Right of First Refusal:** The Remaining Shareholders shall have the option, exercisable by giving written notice of the exercise of such option (hereinafter in this Article 8 referred to as the "**Purchase Notice**") to the Selling Shareholder and the Corporation within ninety (90) days (hereinafter in this Article 8 referred to as the "**Right of First Refusal Period**") subsequent to the date of deemed receipt, pursuant to Section 15.1 hereof, by the Remaining Shareholders of the Sale Notice, to purchase all but not less than all of the Offered Shares, on a Pro Rata basis, determined on the basis of the ratio of the number of Shares owned by each Remaining Shareholder to the number of Shares owned by all Remaining Shareholders at the Purchase Price and the terms set forth in the Sale Notice. If all the Offered Shares have not been purchased by the Remaining Shareholders then the remaining Offered Shares shall be offered to those Remaining Shareholders which have purchased Offered Shares on a Pro Rata basis until all of the Offered Shares have been purchased. The closing of the sale of the Offered Shares shall occur on the first Business Day following the expiry of the sixty (60) day period following the date of deemed receipt, pursuant to Section 15.1 hereof, by the Remaining Shareholders and the Corporation of the Purchase Notice or, if the completion of such sale requires the prior approval of or notice to a third Person or Governmental Authority under Applicable Law or any instrument or agreement, within thirty (30) Business Days after receipt of such approval or required period of notice or on such later date as may be agreed by the Parties.

8.3 **Sale of Shares:** In the event that the Remaining Shareholders do not exercise their right of first refusal pursuant to Section 8.2, the rights of the Remaining Shareholders, subject as hereinafter provided, to purchase the Offered Shares shall forthwith terminate and the Selling Shareholder, subject to the restrictions on transfer or sale specified in Section 13.5 hereof, may sell the Offered Shares to any Person (the "**Prospective Purchaser**") within ninety (90) days after the termination of the Right of First Refusal Period, for a price not less than the Purchase Price and on other terms no more favourable to the Prospective Purchaser than those set forth in the Sale Notice, provided that the Prospective Purchaser agrees prior to such transaction to be bound by this Agreement and to become a party hereto in place of the Selling Shareholder with respect to the Offered Shares. If the Offered Shares are not sold within such ninety (90) day period, or, if the completion of such sale requires the prior approval of or notice to a third Person or Governmental Authority under Applicable Law or any instrument or agreement, within thirty (30) Business Days after receipt of such approval or any required period of notice, on such terms, the rights of the Remaining Shareholders pursuant to Sections 8.1 and 8.2 shall again take effect and so on from time to time.

8.4 **Moratorium on Sales While Purchase Offer Outstanding:** Once a Shareholder gives a Sale Notice pursuant to Section 8.1 hereof, for a period of one (1) year, no other Shareholder shall be entitled to give a Sale Notice with respect to Shares until such time as the Offered Shares are either sold to the Remaining Shareholders, or a Prospective Purchaser, as the case may be, in accordance with the terms of this Article 8 or the sale of such Shares to the Prospective Purchaser does not occur within the time limits prescribed in Section 8.3. No Shareholder may proceed with any sale of any of the Shares owned by it without complying with the relevant provisions of this Agreement.

ARTICLE 9 – TAG-ALONG/DRAG ALONG RIGHTS

9.1 **Tag-Along Rights**:

(a) In the event that a Shareholder, or Shareholders together, owning a majority of the Shares (the “Majority Shareholder”) proposes to sell all of its Shares (the “**Offered Majority Shares**”) to an Arm's Length third party (the "**Third Party**") pursuant to Section 8.3, then the Majority Shareholder shall, within thirty (30) days following the expiry of the ninety (90) day period referred to in Section 8.3 of the Corporation, give written notice (the "**Tag-Along Notice**") of the identity of the Third Party and the price and other material terms of the transaction (which shall be consistent with the requirements of Section 8.1) to the owners of less than fifty percent (50%) of the Shares (the “Minority Shareholders”). The Minority Shareholders (each a “Minority Selling Shareholder”) may, not later than ninety (90) Business Days after receipt of the Tag-Along Notice, deliver to the Majority Shareholder a notice in writing invoking the provisions of this Section 9.1 (a "**Tag-Along Demand**"). The delivery by a Minority Selling Shareholder of a Tag-Along Demand shall be irrevocable and shall bind such Minority Selling Shareholder to sell all, but not less than all, of the Shares owned by such Minority Selling Shareholder(the "**Tag-Along Shares**"), in accordance with the provisions of this Section 9.1.

(b) If a Minority Shareholder delivers a Tag-Along Demand, then, before completing any sale, the Majority Shareholder shall cause the Third Party to deliver to each Minority Selling Shareholder a bona fide offer in writing (the "**Tag-Along Offer**") to purchase the Tag-Along Shares from such Minority

Selling Shareholder. The Tag-Along Offer will be binding upon the Third Party and shall contain only such terms and conditions as are identical to those upon which the Majority proposes to sell to the Third Party the Offered Majority Shares pursuant to Section 8.3, provided that the offer price per Share, which shall be specified in the Tag-Along Offer, shall be the same consideration as the consideration per Share at which the Majority Selling Shareholder proposes to sell to the Third Party the Offered Majority Shares pursuant to Section 8.3.

(c) The closing date and other closing arrangements for the purchase and sale transaction between the Majority Shareholder and the Third Party shall be specified in the Tag-Along Offer and shall be the same, *mutatis mutandis*, as those specified between the Third Party and the Minority Shareholder.

9.2 **Drag-Along Rights**:

(a) In the event that the Majority Shareholder proposes to sell the Offered Majority Shares to a Third Party pursuant to Section 8.3 and a Minority Shareholder (a "Non-Selling Minority Shareholder)(has not exercised its Tag Along rights under Section 9.1, then the Majority Shareholder may, by written notice to the Non-Selling Minority Shareholders delivered within thirty (30) days following the expiry of the ninety (90) day period referred to in Section 9.1, accompanied by an irrevocable offer (the "**Drag-Along Offer**") from the Third Party to the Non-Selling Minority Shareholders to purchase, for a consideration that is the same as the consideration per Share at which the Majority Shareholder proposes to sell the Offered Majority Shares to the Third Party pursuant to Section 8.3, the Shares owned by the Non-Selling Minority Shareholders (the "**Dragged Shares**"), require the Non-Selling Minority Shareholder to sell to the Third Party all such Dragged Shares at the price specified in the Drag-Along Offer.

(b) The delivery by the Majority Shareholder of an irrevocable Drag-Along Offer shall bind the Non-Selling Minority Shareholder to sell the Dragged Shares. The date on which the sale is to close and the other closing arrangements (which shall be the same, *mutatis mutandis*, as those for the purchase and sale between the Third Party and the Majority Shareholder) shall be as specified in the Drag-Along Offer. Except as specifically provided for above, the Drag-Along Offer shall contain only such terms and conditions, if any, as are identical to those pursuant to which the Majority Shareholder proposes to sell to the Third Party the Offered Shares.

ARTICLE 10- BUY-SELL RIGHTS

10.1 **Buy-Sell:**

(1) Any Shareholder (in this Section 10.1, an "**Offeror**") may give notice (a "**Purchase or Sale Notice**") to the other Shareholders (in this Section 10.1, the "**Other**

Shareholders") of a proposed purchase or sale of Shares. The Purchase or Sale Notice shall constitute an offer (the "**Purchase Offer**") by the Offeror to the Other Shareholders to purchase all but not less than all of the issued and outstanding Shares held by the Other Shareholders at the Notice Date at a specified purchase price per Share (the "**Buy-Sell Share Price**") and shall in the alternative constitute an offer (the "**Sale Offer**") by the Offeror to sell all but not less than all of the issued and outstanding Shares held by the Offeror at the date of the Purchase or Sale Notices (in this Section 10.1, the "**Affected Shares**"; and the date of the Purchase or Sale Notices, in this Section 10.1, the "**Notice Date**") at the Buy-Sell Share Price. The Purchase and Sale Notices shall:

(a) be made in writing by the Offeror and be made concurrently to all Other Shareholders in the same manner (whether by delivery, prepaid courier service or facsimile); and

(b) state the Buy-Sell Share Price.

The offers constituted by each Purchase or Sale Notice shall be irrevocable and shall remain open for acceptance by the Other Shareholders for a period of ninety (90) days after the date of the Purchase and Sale Notice.

(2) Each of the Other Shareholders shall have the right, exercisable by notice (in this Section 10.1, an "**Acceptance**") given to the Offeror within the period during which the offers constituted by the Purchase or Sale Notice is open for acceptance under Section 10.1(1) to accept the Purchase Offer and agree to sell to the Offeror all of that Other Shareholder's issued and outstanding Shares or to reject that offer and to accept the Sale Offer and agree to purchase the Affected Shares. If no Acceptance is given by an Other Shareholder under this Section 10.1(2), that Other Shareholder shall be deemed to have accepted the Purchase Offer constituted by the Purchase or Sale Notice.

(3) If one or more of the Other Shareholders accept the Sale Offer, the Purchase Offer shall be deemed to have been rejected by all of the Other Shareholders. If only one Other Shareholder accepts the Sale Offer, that Other Shareholder shall be deemed to have agreed to purchase all of the Affected Shares. If two or more Other Shareholders accept the Sale Offer (in this Section 10.1, the "**Purchasing Shareholders**"), each of such Purchasing Shareholders shall be deemed to have agreed to purchase that number of the Affected Shares which bears the same relationship to the total number of Affected Shares as the number of issued and outstanding Shares held by each such Purchasing Shareholder bears to the total number of issued and outstanding Shares held by all Purchasing Shareholders (as reflected on the securities registers of the Corporation) at the Notice Date.

(4) The completion of all purchases of Affected Shares or of the Shares held by the Other Shareholders, as the case may be, under this Section 10.1 shall occur on the thirtieth (30^{th}) day after the expiry of the period during which the offers constituted by the Purchase and Sale Notice are open for acceptance.

(5) Once a Shareholder gives a Purchase or Sale Notice, no Other Shareholder may give a Purchase or Sale Notice with respect to Shares, until such time as either the Affected Shares are sold to the Purchasing Shareholders or the Shares held by the Other Shareholders are sold to the Offeror pursuant to this Section 10.1.

ARTICLE 11 - PUT OPTION

11.1 Put Option:

(a) The Shareholders other than the Majority Shareholder (in this Section 11.1, the "**Other Shareholders**") shall have the irrevocable right and option (the "**Put Option**") by notice to Majority Shareholder and the Corporation with a copy to the other Shareholders, to force the purchase by the Majority Shareholder or the Corporation, of all of the Shares held by that Other Shareholder at a total purchase price equal to the Put Option Price described in Section 11.1(b) below. The closing of the Put Option shall occur on the thirtieth (30^{th}) day after the deemed receipt of notice of the exercise of the Put Option pursuant to Section 15.1 by the Majority Shareholder and the Corporation.

(b) The "**Put Option Price**" for the purposes of this Article 11 shall mean the fair market value of each Share in which the Shareholder is deemed to have exercised the Put Option. Such Put Option Price shall be determined in a manner provided in Schedule A with the sixty (60) days immediately following the date of exercise of the Put Option.

ARTICLE 12 - PURCHASE OF SHARES ON DEEMED WITHDRAWAL

12.1 Deemed Withdrawal from the Corporation:

(a) Subject to 12.1(b), for the purposes of this Article 12, a Shareholder shall be deemed to withdraw from the Corporation on that date (the “Withdrawal Date”) when such Shareholder,

(i) or its Controlling Shareholder: (i) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy or similar Applicable Law for the protection of creditors, including, the *Bankruptcy and Insolvency Act* (Canada) and the *Companies Creditors Arrangement Act* (Canada), the *Municipal Affairs Act* (Ontario) or other statute applicable to insolvent municipalities or has such petition filed against it and such petition is not withdrawn or dismissed for sixty (60) days after such filing; (ii) otherwise becomes bankrupt or insolvent (however evidenced); or (iii) is unable to pay its debts as they fall due;

(ii) fails, refuses or neglects to conform materially to any of the terms and conditions of this Agreement, and fails to remedy any such default within thirty (30) days of the deemed receipt, pursuant to Section 15.1 hereof, of a written notice from any other Shareholder giving details of such default; or (iii) has all or any portion of its Shares of the Corporation realized upon by an encumbrancer.

(b) The Shareholders may unanimously agree to waive the provisions of this Article 12 with respect to any Shareholder that would otherwise have been deemed to withdraw from the Corporation pursuant to Section 12.1(a)

12.2 **Purchase of Shares on a Shareholder's Withdrawal from the Corporation:** In the event that a Shareholder is deemed to have withdrawn from the Corporation pursuant to the provisions of Section 12.1(a) hereof and the Shareholders have not agreed to waive the application of this Article 12 in accordance with Section 12.1(b), the Corporation irrevocably agrees to purchase, on the expiry of the ninety (90) day period following the occurrence of such event, all and not less than all of the Shares of the Shareholder which is deemed to have withdrawn from the Corporation (hereinafter in Section 12.2 referred to as the "**Withdrawing Shareholder**") at the Share Purchase Price. The closing of the sale of the Shares of the Withdrawing Shareholder to the Corporation shall take place at the offices of the Corporation at the address designated in Section 15.1 hereof at 10:00 in the morning (Toronto time) on the first Business Day following the expiry of the aforesaid ninety (90) day period. The Share Purchase Price, determined pursuant to Section 12.4 hereof, shall be paid at such closing in Canadian dollars. In the event that the Corporation is not, at the time of such purchase of Shares, capable of fulfilling its obligations to pay for such Shares, either because it cannot do so in compliance with the OBCA, or other Applicable Law to the same effect, the sale of such Shares to the Corporation shall be completed with the balance of the Share Purchase Price for such Shares to be paid by the Corporation as soon as it is lawfully able to do so.

12.3 **Sale of Shares on Deemed Withdrawal from the Corporation:**

(a) The Withdrawing Shareholder hereby irrevocably offers to sell all of its Shares to the Corporation at a price per Share (hereinafter in this Article 12 the "the Share Purchase Price") determined in the manner provided in Section 12.4 hereof and Schedule A hereto.

(b) In all of the circumstances provided in Section 12.1(a), the remaining Shareholders shall have the right to require that the Corporation assign to them the right or obligation of the Corporation to purchase any or all of the Shares of a Withdrawing Shareholder and, pursuant to such assignment, the remaining Shareholders shall have the right to purchase such Shares, provided that in the opinion of tax counsel to the Corporation, the Withdrawing Shareholder will suffer no significant prejudice from an income tax perspective as a result of such Shares being purchased by the remaining Shareholders rather than by the Corporation.

(c) In the event that the remaining Shareholders purchase such Shares, they shall be entitled to purchase them on a Pro Rata basis in proportion to their respective holdings of Shares or in any other proportion as they may choose, and the provisions of Section 12.2 of this Agreement shall apply *mutatis mutandis* provided however, that no Shareholder shall be obliged to purchase any such Shares.

12.4 **Share Purchase Price Determination:** The Share Purchase Price for the purposes of this Article 12 shall mean the fair market value of each Share as determined at the Withdrawal Date. Such Share Purchase Price shall be determined in the manner provided in Schedule A hereto within the sixty (60) days immediately following the Withdrawal Date.

12.5 **Cancellation of Shares:** Upon the acquisition of any Shares by the Corporation pursuant to this Article 12 of this Agreement, such Shares shall be cancelled and shall not be reissued.

ARTICLE 13 - PROVISIONS APPLICABLE TO SALES OF SHARES PURSUANT TO THIS AGREEMENT

13.1 **Application to All Sales:** Except as, or in addition to, what may otherwise be provided in this Agreement, this Article 13 shall apply to any sale of Shares effected pursuant to the provisions of this Agreement.

13.2 **Closing:** The closing of all sales of Shares effected pursuant to this Agreement shall take place at the offices of the Corporation at the address designated in Section 15.1 hereof, at 10:00 in the morning (Toronto time) on the date stipulated, either pursuant to the provisions hereof or pursuant to any agreement executed in connection with any such sale, as the date on which such closing is to occur.

13.3 **Cancellation of Share Certificates:** The President of the Corporation, or such other officer as may be designated by resolution of the directors of the Corporation shall attend all closings of any such sale of Shares and shall deliver to the Corporation for cancellation share certificates evidencing Shares which are to be sold and shall take custody of new share certificates, if any, issued in replacement of such cancelled share certificates so that at all times the Corporation shall have custody of share certificates representing all of the Shares.

13.4 **Resignation of Seller's Nominees:** At the closing of any sale of Shares, the Shareholder selling its Shares shall cause to be delivered to the Corporation signed resignations of its nominees as directors of the Corporation, and shall assign and transfer to the purchaser of such Shares, all of its right, title and interest in such Shares.

13.5 **Transfer Taxes and Other Tax Impacts of a Proposed Sale:**

(a) In the event that any proposed sale or transfer of Shares would result or results in tax or an amount in respect of payments in lieu of tax being exigible from the Corporation or any Shareholder other than the Shareholder selling its Shares (the "**Non-Selling Shareholder(s)**"), whether transfer tax, income tax, capital tax or other tax (and including any taxes or related expenses resulting from the Corporation no longer being tax exempt pursuant to Section 149(1)(d.6) of the *Income Tax Act* (Canada)), all such tax and expenses shall be an expense to the purchaser which shall indemnify the Corporation with respect thereto, and notwithstanding any other provision of this Agreement to the contrary, the proposed sale or transfer shall not be completed unless all such tax and expenses of the Corporation or any Non-Selling Shareholder are first paid in full by the purchaser ; provided that if a proposed sale or transfer is pursuant to the Article 11 Put Option or the Article 12 Deemed Withdrawal, any eligible tax is payable by the Selling Shareholder and the provisions above shall apply *mutatis mutandis*.

(b) A Shareholder selling Shares to any Person shall, as required by the Electricity Act or any other Applicable Law, pay all transfer taxes payable under the Electricity Act in respect of such sale such that the sale shall not be void.

13.6 **Additional Provisions: Loans, Guarantees:** In conjunction with any sale of all Shares:

(a) if the Shareholder selling all of its Shares is indebted to the Corporation, the Corporation may, at its option, require such Shareholder to repay in full all indebtedness which it owes to the Corporation on or before the closing of such sale of Shares;

(b) if the Corporation is indebted to the Shareholder selling all of its Shares, the Shareholder selling Shares may, at its option, require the Corporation to repay in full all indebtedness which it owes to such Shareholder on or before the closing of such sale of Shares; and

(c) if the Shareholder selling all of its Shares has provided a guarantee, letter of credit, security or other financial assistance to the Corporation, the Corporation shall use its commercially reasonable efforts to replace or release such guarantee, letter of credit, security or other financial assistance within ninety (90) days after the closing of such sale of Shares.

ARTICLE 14 - NON-COMPETITION AND CONFIDENTIALITY

14.1 **Non-Competition:** During the period commencing as of the date of this Agreement and terminating on the expiry of the twelve (12) months following the date on which a Shareholder:

(a) is deemed to withdraw from the Corporation, pursuant to Section 14.1 of this Agreement; or

(b) sells all of its Shares in accordance with this Agreement,

such Shareholder shall not, and shall use its commercially reasonable efforts to ensure that its shareholders do not, individually or in partnership or in conjunction with any Person, as principal, agent, shareholder, consultant or otherwise, directly or indirectly, carry on or be engaged in, or advise, acquire an interest in, or permit its name or any part thereof to be used or employed by an association, syndicate or corporation engaged in or concerned with or interested in, the business of distributing electricity as regulated by the OEB unless the consent of the other Shareholders has first been obtained.

14.2 **Necessary Covenants:** Each Shareholder hereby confirms that all restrictions in this Article 14 are reasonable and valid, that they are necessary for the protection of the Corporation's legitimate interests and that they do not unduly affect their earning capacity, and waive all defences to the strict enforcement thereof.

14.3 **Confidential Information:** The Shareholders hereby acknowledge that they have had and will have access to confidential information and trade secrets concerning the Business, the Corporation, and the Corporation's Affiliates (as defined in the OBCA), if any, and their customers and suppliers (hereinafter in this Article 14 referred to as the "**Information**") and they each undertake and agree that they shall not, and their Controlling Shareholder shall not, directly or indirectly, use, disclose or divulge to any Person or other entity any of the Information otherwise than in the Ordinary Course of Business of the Corporation, and its Affiliated Bodies Corporate and as may be required by Applicable Law or order of any Governmental Authority.

14.4 **Survival of Obligations:** The obligations and covenants in this Article 14 shall survive the termination of this Agreement.

ARTICLE 15 - NOTICES

15.1 **Notices:** Any notice or other communication required or permitted to be given under this Agreement shall be in writing and shall be given by facsimile or other means of electronic communication or by hand-delivery as provided below. Any such notice or other communication, if sent by facsimile or other means of electronic communication, shall be deemed to have been received on the Business Day following the sending, or if delivered by hand, shall be deemed to have been received at the time it is delivered to the applicable address noted below either to the individual designated below or to an individual at such address having apparent authority to accept deliveries on behalf of the addressee. Notice of change of address shall also be governed by this Section 11.1. Notices and other communications shall be addressed as follows:

(a) in the case of PWPI:

4548 Ontario Street
Unit 2
Beamsville, ON L0R 1B5

Attention: President
Fax No.: 905-563-0838

(b) in the case of NFHC:

7447 Pin Oak Drive
P.O. Box 120
Niagara Falls, ON L2E 6S9

Attention: President
Fax No.: 905-356-0118

(c) in the case of the Corporation:

7447 Pin Oak Drive
P.O. Box 120
Niagara Falls, ON L2E 6S9

Attention: President
Fax No.: 905-356-0118

Notwithstanding the foregoing, any notice of arbitration permitted to be given by any party pursuant to or in connection with any arbitration procedures in Section 16.2 may only be delivered by hand. Normal communications during the arbitration process itself may be delivered by facsimile, regular mail or by hand-delivery. The failure to send or deliver a copy of a notice to counsel shall not invalidate any notice given under this Section 15.

ARTICLE 16- DISPUTE RESOLUTION

16.1 **Disputes:** Each Shareholder shall appoint one or more representatives who shall be responsible for administering this Agreement on its behalf and for representing its respective interests in disputes relating to this Agreement. Any dispute between Shareholders relating to this Agreement that is not resolved between such representatives within ten (10) Business Days of a date that a Party notifies the other Party of such dispute shall be referred by the Parties' representatives in writing to the senior management of each Shareholder for resolution. Such senior management shall use good faith efforts to resolve the dispute for a period of up to ten (10) Business Days.

16.2 **Arbitration:** If a dispute is not resolved by the procedure set forth in Section 16.1 above, such dispute may, by any Party, be referred to and resolved by arbitration by a single arbitrator in accordance with the provisions of the *Arbitration Act, 1991* (Ontario), subject to the following modifications and additions:

(a) The arbitration shall take place in the Province of Ontario, and shall be conducted in English;

(b) The arbitration shall be conducted by a single arbitrator having no financial, business or personal interest in the outcome of the arbitration. The arbitrator shall be appointed jointly by agreement of the parties to such dispute. In the event the parties to such dispute are unable to agree on the appointment of the arbitrator within ten (10) days after notice of a demand for arbitration is given by a party and agreed to by the other parties to such dispute, then the arbitrator shall be selected pursuant to the provisions of the *Arbitration Act, 1991* (Ontario).

(c) The arbitrator shall have the authority to award any remedy or relief that a court could order or grant in accordance with this Agreement including, without limitation, specific performance of any obligation, the issuance of an interim, interlocutory or permanent injunction, or the imposition of sanctions for abuse or frustration of the arbitration process.

(d) The arbitrator shall have sole and exclusive jurisdiction to examine into, hear and determine all matters and questions of fact and law in respect of which any powers or authority has been conferred upon the arbitrator, including questions of jurisdiction. The arbitral award shall be in writing, stating the reasons for the award and shall be final and conclusive and is not open to appeal, question or review in any court and any determination by the arbitrator made under this Article is hereby ratified and confirmed and is binding upon all persons. No proceedings by or before the arbitrator shall be restrained by injunction, prohibition or other process or proceeding in any court, or are removable by certiorari or otherwise into any court.

ARTICLE 17 - MISCELLANEOUS

17.1 **Termination:** This Agreement shall terminate upon (a) the written agreement of all the Parties hereto to this effect, (b) the bankruptcy, receivership or dissolution of the Corporation, or (c) the ownership of all the Shares of the Corporation by one Shareholder.

17.2 **Successors and Assigns:** This Agreement shall be binding upon, and enure to the benefit of, the Parties hereto and their respective successors and permitted assigns.

17.3 **Assignment:** Except as specifically provided in this Agreement, none of the Parties hereto may assign its rights or obligations under this Agreement without the prior written consent of all of the other Parties hereto.

17.4 **Time is of the Essence:** Time shall be the essence of this Agreement in all respects.

17.5 **Further Assurances:** Each Party hereto shall promptly do, execute, deliver or cause to be done, executed and delivered all further acts, documents and matters in connection with this Agreement that the other Parties may reasonably require, for the purposes of giving effect to this Agreement.

17.6 **Counterparts:** This Agreement may be executed in any number of counterparts, each of which shall be deemed to be an original and all of which taken together shall be deemed to constitute one and the same instrument. Counterparts may be executed either in original or telecopied form and the Parties shall accept any signatures received by a receiving telecopy machine as original signatures of the Parties; provided, however, that any Party providing its signature in such manner shall promptly forward to the other Parties an original of the signed copy of this Agreement which was so telecopied.

17.7 **Governing Law:** This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the federal laws of Canada applicable therein. The Parties agree that the courts of Ontario shall have exclusive jurisdiction to determine all disputes and claims arising under or pursuant to this Agreement.

17.8 **Amendments and Waivers:**

(a) No amendment to this Agreement shall be valid or binding unless set forth in writing and duly executed by all of the Parties hereto.

(b) No waiver of any breach of any provision of this Agreement shall be effective or binding unless made in writing and signed by the Party purporting to give the same and, unless otherwise provided in the written waiver, shall be limited to the specific breach waived.

17.9 **Severability:** If any provision of this Agreement is determined to be invalid or unenforceable in whole or in part, such invalidity or unenforceability shall attach only to such provision or part thereof and the remaining part of such provision and all other provisions hereof shall continue in full force and effect.

[EXECUTION PAGE FOLLOWS]

IN WITNESS WHEREOF the Parties hereto have executed this Agreement as of the day first above written.

NIAGARA FALLS HYDRO HOLDING CORPORATION

By: Suzanne Wilson

By:
Name:
Title:

By: M. A. Sforza

Name:
Title:

PENINSULA WEST POWER INC.

By: Brian Walker

Name:
Title:

By:
Name:
Title:

NIAGARA PENINSULA ENERGY INC.

By:
Name:
Title:

Brian Walker

By:
Name:
Title:

[EXECUTION PAGE TO SHAREHOLDERS AGREEMENT]

Privileged and Confidential

SCHEDULE A

VALUATION METHOD

In this Schedule, the vendor and the purchaser of the Shares being sold pursuant to Article 11 or Article 12 of this Agreement are called the "Vendor" and the "Purchaser", respectively.

Negotiation. If the value of the Shares must be established pursuant to any provision of this Agreement, then the Vendor and the Purchaser shall negotiate honestly and in good faith to agree upon the fair market value of the Shares and such value as the parties may agree upon shall be deemed to be the fair market value of these shares for all purposes of this Agreement.

Failure to Agree. If the Vendor and the Purchaser do not agree upon the fair market value of the Shares on or before the 20th Business Day after the date on which the obligation to sell or purchase Shares arises under this Agreement, then the value of the Shares shall be determined in accordance with the following provisions:

(a) the Vendor and Purchaser shall agree on the choice of an independent business valuator who deals at Arm's Length with both the Vendor and Purchaser and has experience in valuing businesses similar to the business carried on by the Corporation ("Valuator") with in a further ten (10) days; provided that if the Vendor and Purchaser do not agree on the choice of a Valuator as specified above, either party may apply to a single Judge of the Ontario Superior Court of Justice who will appoint a Valuator;

(b) the business valuator so selected shall be the "Valuator" for the purposes of this Agreement and shall proceed to determine the fair market value of all of the Shares being sold in accordance with the provisions of this Schedule A.

Valuation by Valuator. The Valuator agreed upon or selected in accordance with this Schedule A to determine the fair market value of the Shares being sold shall act as a business valuator and not as an arbitrator or umpire. The Valuator shall apply such business valuation principles as the Valuator deems appropriate. The Valuator may consult such other expert valuators as it considers advisable. The fair market value of the Shares shall be determined without regard for any restrictions applying to the transfer of Shares. The fees and disbursements of the Valuator shall be borne equally by the Vendor and the Purchaser.

Valuation Conclusive. The determination of the value of the Shares being sold pursuant to this Agreement in accordance with this Schedule A, whether based upon the agreement of the Vendor and the Purchaser or the determination by the Valuator, shall be conclusive and binding upon the Vendor and the Purchaser, and there shall be no appeal from the determination.

Appendix 1-14

2021 COS checklist used for 2021 COS rate applications

2021 Cost of Service Checklist

Niagara Peninsula Energy Inc.

EB-2020-0040

Date:

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
GENERAL REQUIREMENTS		
Ch 1, Pg. 2	Certification by a senior officer that the evidence filed is accurate, consistent and complete	1.3.3
Ch 1, Pg. 3-4	Confidential Information - Practice Direction has been followed	1.3.20
Ch 2, Pg. 1	Statement identifying all deviations from Filing Requirements	1.3.12
2	Chapter 2 appendices in PDF and live Microsoft Excel format; PDF and Excel copy of current tariff sheet	Appendix 8-4
3	If applicable, late applications filed after the commencement of the rate year for which the application is intended to set rates is converted to the following rate year.	NA
3	Aligning rate year with fiscal year - request for proposed alignment	1.3.10
4	Text searchable and bookmarked PDF documents	Exhibits 1 to 9 and the DSP
5	Links within Excel models not broken and models names so that they can be identified (e.g. RRWF instead of Attachment A)	Yes
5	Materiality threshold; additional details beyond the threshold if necessary (for rate base, capital expenditures and OM&A)	1.6.1
RESS Guideline	Two hardcopies of application sent to OEB the same day as electronic filing (p10 of RESS Guideline)	No
EXHIBIT 1 - ADMINISTRATIVE DOCUMENTS		
Table of Contents		
6	Table of Contents listing major sections and subsections of the application. Electronic version of application appropriately bookmarked to provide direct access to each section	Exhibits 1 to 9 each have their own Table of Contents
Executive Summary		
6	Summary identifying key elements of the proposals and the Business Plan underpinning application, as guided by the Rate Handbook including plain language information about its goals	1.2.2
Customer Summary		
7	Brief but complete summary of the application that will be posted as a stand-alone document on the OEB's website for review by the general public and be made available to customers of the applicant. Must include: main requests (with section references), description of impacts of requests, bill impact for customer at 750kWh as well as a typical consumer for a distributor's service area for each of the residential and small business customer classes	1.5.1 to 1.5.10
Administration		
7	Primary contact information (name, address, phone, fax, email)	1.3.2
7	Identification of legal (or other) representation	1.3.4
7	Applicant's internet address for viewing of application and any social media accounts used by the applicant to communicate with customers	1.3.5
7	Statement identifying customers materially affected by the application including any change to any rate or charge and specific statement of what individual customer or customer groups would be affected by the proposed change	1.3.6
7	Statement identifying where notice should be published and why	1.3.7
7	Bill impacts - distribution only impacts for 750 kWh residential and 2000 kWh GS<50 (sub-total A of Tariff Schedule and Bill Impact Spreadsheet Model) to be used for notice; proposed bill impacts based on alternative consumption profiles and customer groups as appropriate given consumption patterns of a distributors customers	1.3.8
7	Form of hearing requested and why	1.3.9
7	Requested effective date	1.3.10
7	Statement identifying and describing any changes to methodologies used vs previous applications	1.3.11
7	Identification of OEB directions from any previous OEB Decisions and/or Orders. The applicant must clearly indicate how these are being addressed in the current application (e.g., filing of a study as directed in a previous decision)	1.3.13 and 1.3.14
7 & 8	Reference to Conditions of Service - LDC does not need to file Conditions of Service, but must provide reference to website and confirm version is current; identify if there are changes to Conditions of Service (a) since last CoS application or (b) as a result of the current application. Confirmation that there are no rates and charges linked in the Conditions of Service that are not in the distributor's Tariff of Rates and Charges must be provided	1.3.15
8	Description of the corporate and utility organizational structure, showing the main units and executive and senior management positions within the utility. Include a corporate entities relationship chart, showing the extent to which the parent company is represented on the utility company's Board of Directors and a description of the reporting relationships between utility and parent company management. Also include any planned changes in corporate or operational structure, including any changes in legal organization and control	1.3.16 and 1.3.17

2021 Cost of Service Checklist

Niagara Peninsula Energy Inc.

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Date:

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
8	List of approvals requested (and relevant section of legislation), including accounting orders - a PDF copy of Appendix 2-A should be provided in this section	1.3.23 and Appendix 1-1
Distribution System Overview		
8	Description of Service Area (including map, communities served)	1.4.1
8	Description of whether the distributor is a host distributor and/or embedded distributor. Identification of embedded and/or host distributors; if partially embedded provide %load from host distributor. If the distributor is a host, the applicant should identify whether there is a separate Embedded Distributor customer class or if any embedded distributors are included in other customer classes such as GS > 50 kW	1.4.3
8	Statement as to whether or not the distributor has had any transmission or high voltage assets deemed by the OEB as distribution assets and whether or not there are any such assets the distributor is seeking approval for in this application	1.4.4
Application Summary		
At a minimum, the items below must be provided. Applicants must also identify all proposed changes that will have a material impact on customers.		
9	Revenue Requirement - service RR, increase/decrease ($ and %) from change from previously approved and main drivers	1.5.2
9	Budgeting and Accounting Assumptions - economic overview and identification of accounting standard used for test year and brief explanation of impacts arising from any change in standards	1.5.3
9	Load Forecast Summary - load and customer growth, % change in kWh/kW and customer numbers, description of forecasting method(s) used for customer/connection and consumption/demand	1.5.4
9	Rate Base and DSP - major drivers of DSP, rate base for test year, change in rate base from last approved ($ and %), capital expenditures requested for the test year, change in capital expenditures from last approved ($ and %), summary of costs requested for renewable energy connections/expansions, smart grid, and regional planning initiatives, any O.Reg 339/09 planned recovery	1.5.5
9 & 10	OM&A Expense - OM&A for test year and change from last approved ($ and %), summary of drivers and cost trends, inflation assumed, total compensation for test year and change from last approved ($ and %).	1.5.6
10	Cost of Capital - summary table showing proposed capital structure and cost of capital parameters used in WACC. Statement regarding use of OEB's cost of capital parameters; summary of any deviations	1.5.7
10	Cost Allocation & Rate Design - summary of any deviations from OEB methodologies, significant changes proposed to revenue-to-cost ratios and fixed/variable splits and summary of proposed mitigation plans	1.5.8
10	Deferral and Variance Accounts - total disposition (RPP and non-RPP), disposition period, new accounts requested and any requested discontinuation of existing DVAs	1.5.9
10	Bill Impacts - total impacts ($ and %) for all classes for typical customers	1.5.10
Customer Engagement		
10	Discussion on how customers were informed of the proposals being considered for inclusion in the application and the value of those proposals to customers i.e. costs, benefits, and the impact on rates	1.7.1
10	Discussion of any feedback provided by customers and how the feedback shaped the final application	1.7.1
10	Impact of customer engagement activities on the development of the capital plan are to be filed as part of the capital plan requirements in Chapter 5	1.7.3
11	Reference to any other communication sent to customers about the application i.e. bill inserts, town hall meetings or other forms of out reach and the feedback received from customers through these engagement activities. Provide summary of feedback received through engagement activities.	1.7.1
11	Complete Appendix 2-AC Customer Engagement Activities Summary - explicit identification of the outcomes of customer engagement in terms of the impacts on the distributor's plans, and how that information has shaped the application	1.7.1
11	All responses to matters raised in letters of comment filed with the OEB	1.7.2
Performance Measurement		
11	Discussion of performance for each of the distributor's scorecard measures over the last five years; drivers for its performance, plans for continuous improvement currently and going forward	1.8.1
11 & 12	Identify performance improvement targets, forecast of efficiency assessment using the PEG forecasting model for the test year, discussion on how the results obtained from the PEG model has informed the business plan and application	1.8.7
Financial Information		
12	Non-consolidated Audited Financial Statements for 3 most recent historical years (i.e. 2 years statements must be filed, covering 3 years of historical actuals)	1.9.1
12	Detailed reconciliation of AFS with regulatory financial results filed in the application, including a reconciliation of the fixed assets in order to, as one example, separate non-distribution business. This must include identification of any deviations that are being proposed between AFS and regulatory financial results, including the identification of any prior OEB approvals for such deviations	1.9.2
12	Annual Report and MD&A for most recent year of distributor and parent company, as available and applicable	1.9.3
12	Rating Agency Reports, if available; Prospectuses, etc. for recent and planned public issuances	1.9.4 and 1.9.5
12	Any change in tax status	1.9.6
12	Existing accounting orders and departures from these orders, as well as any departures from the USoA	1.9.7
12	Accounting Standards used for financial statements and when adopted	1.9.8
12	Confirmation that accounting treatment of any non-utility business has segregated activities from rate regulated activities	1.9.9
Distributor Consolidation		
13	If a distributor has acquired or amalgamated with another distributor, identify any incentives that formed part of the acquisition or amalgamation transaction if the incentive represents costs that are being proposed to remain or enter rate base and/or revenue requirement. A distributor must specify whether any commitments made to shareholders are to be funded through rates	1.10.1
13	List of exhibits in application in which incentives are discussed	NA

2021 Cost of Service Checklist

Niagara Peninsula Energy Inc.

EB-2020-0040

Date:

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
13	Description of actual savings as a result of consolidation compared to what was in the approved consolidation application and explanation of how savings are sustainable and the efficacy of any rate plan approved as part of the MAADs application	NA

2021 Cost of Service Checklist

Niagara Peninsula Energy Inc.

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13	Identify approved ACM or ICM from a previous Price Cap IR application it proposes be incorporated into rate base	1.10.2
EXHIBIT 2 - RATE BASE		
Overview		
14	Completed Fixed Asset Continuity Schedule (Appendix 2-BA) - in Application and Excel format	Appendix 2-1
14	For rate base, must include opening and closing balances, average of opening and closing balances for gross assets and accumulated depreciation (discussion of methodology if applicant uses an alternative method); working capital allowance (historical actuals, bridge and test year forecast)	2.1.1
14	Continuity statements (year end balance, including interest during construction and overheads). Explanation for any restatement (e.g. due to change in accounting standards) Year over year variance analysis; explanation where variance greater than materiality threshold Hist. OEB-Approved vs Hist. Actual (for the most recent historical OEB-approved year) Hist. Act. vs. preceding Hist. Act. (for the relevant number of years) Hist. Act. vs. Bridge Bridge vs. Test	2.1.1
14 & 15	Opening and closing balances of gross assets and accumulated depreciation must correspond to fixed asset continuity statements. If not, an explanation must be provided (e.g. CWIP, ARO). Reconciliation must be between net book value balances reported on Appendix 2-BA and balances included in rate base calculation	2.1.1 and Appendix 2-1
15	Distributor may include in-service balances previously recorded in DVAs, such as MIST meters or renewable generation/smart grid related accounts, in its opening test year property, plant and equipment balances, if these costs have not been previously reviewed and approved for disposition, but disposition is being requested in this application. In this situation, the distributor must clearly show in its evidence (e.g. Appendix 2-BA) that the addition was included in the opening test year balances and must reconcile the closing bridge year and opening test year figures. Distributors must provide the same reconciliation for accumulated depreciation	NA
Gross Assets - PP&E and Accumulated Depreciation		
15	Breakdown by function and by major plant account; description of major plant items for test year	2.1.2
15	Summary of approved and actual costs for any ICM(s) and/ or ACM approved in previous IRM applications	1.10.2
15	Continuity statements must reconcile to calculated depreciation expenses and presented by asset account	2.1.3
15	All asset disposals clearly identified in the Chapter 2 Appendices for all historical, bridge and test years and if any amounts related to gains or losses on disposals have been included in Account 1575 IFRS - CGAAP Transitional PP&E Amount	Appendix 2-1
Allowance for Working Capital		
16	Working Capital - 7.5% allowance or Lead/Lag Study or Previous OEB Direction	2.1.4
16	Lead/Lag Study - leads and lags measured in days, dollar-weighted	NA
16	Cost of Power must be determined by split between RPP and non-RPP Class A and Class B customers based on actual data, use most current RPP (TOU) price, use current UTR. Calculation must fully consider all other impacts resulting from the Ontario Electricity Rebate of 31.8% on the total bill. Distributors must complete Appendix 2-Z - Commodity Expense.	Appendix 2-2
Capital Expenditures		
17	DSP filed as a stand-alone document; a discrete element within Exhibit 2	2.3.1
17	Overall summary of capital expenditures over the past five historical years, including the last OEB-approved amounts, as well as the bridge year and the test year. The summary must show capital expenditures, treatment of contributed capital, and additions and deductions from CWIP. As part of Exhibit 2, a distributor must also provide explanations of year-over-year variances and an explanation of the variance, if any, between the OEB-approved capital expenditure amount in the last rebasing year as compared to the actual expenditures for that year.	2.2.2 and Appendix 2-3 and Appendix 2-4
17	Complete Appendix 2-AB - four historical years must be actuals, forecasts for the bridge and test years; at a minimum, for historical years, applicants must provide actual totals for each DSP category. If no previous plan has been filed, applicants are only required to enter their planned total capital budget in the "plan" column for each historical year and for the bridge year including the OEB-approved amount for the last rebasing year	2.2.2 and Appendix 2-3
Policy Options for the Funding of Capital		
18	Distributor may propose ACM capital project coming into service during Price Cap IR (a discrete project documented in DSP). Provide cost and materiality calculations to demonstrate ACM qualification	2.2.6
18	Distributor must establish need for and prudence of these projects based on DSP information; identification that distributor is proposing ACM treatment for these future projects, preliminary cost information	NA
18	Complete Capital Module Applicable to ACM and ICM	NA
Addition of Previously Approved ACM and ICM Project Assets to Rate Base		
19	Distributor with previously approved ACM(s) and/or ICM(s) - schedule of ACM/ICM amounts proposed to be incorporated into rate base. The distributors must compare actual capital spending with OEB-approved amount and provide an explanation for variances	2.2.7
20	Balances in Account 1508 sub-accounts, reconciliation with proposed rate base amounts; recalculated revenue requirement should be compared with rate rider revenue	NA
20	Accelerated capital cost allowance (CCA) should not be reflected in the ACM/ICM revenue requirement associated with these projects. Distributors should include the impact of the CCA rule change associated with the ACM/ICM project(s) in Account 1592 - PILs and Tax Variances – CCA Changes sub-account for CCA changes	NA
Capitalization Policy and Capitalization		

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20	Changes to capitalization policy since its last rebasing application as a result of the OEB's letter dated July 17, 2012 or for any other reasons, the applicant must identify the changes and the causes of the changes.	2.2.3
21	Appendix 2-D complete; identification of burden rates and burden rates prior to changes, if any	2.2.4 and Appendix 2-6
Costs of Eligible Investments for the Connection of Qualifying Generation Facilities		
21 & 22	Generation Facilities - If applicable, proposal to divide the costs of eligible investments between the distributor's ratepayers and all Ontario ratepayers per O.Reg. 330/09. Request for rate protection exceeds the materiality threshold in section 2.0.8 of the Filing Requirements - Appendices 2-FA through 2-FC identifying all eligible investments for recovery	2.2.5
Service Quality		
22	5 historical years of SQRs, explanation for any under-performance vs standard and actions taken	2.2.8
22	Completed Appendix 2-G; confirmation that the data is consistent with scorecard, or explanation of any inconsistencies	Appendix 2-7
Ch5 p7-8	Where applicable, explanation for section headings other than Chapter 5 headings; cross reference table	NA Chapter 5 headings were used
Ch5 p8-9	Distribution System Plan Overview - key elements, sources of cost savings, period covered, vintage of information on investment drivers, changes to asset management process since last DSP filing, dependencies	CHP 5 - 5.2.1
Ch5 p9-10	Coordinated Planning with 3rd parties - description of consultations - deliverables of the Regional Planning Process, or status of deliverables - IESO letter in relation to REG investments (Ch 5 p9) and Dx response letter	CHP 5 - 5.2.2
Ch5 p10-12	Performance Measurement - identify and define methods and measures used to monitor DSP performance - summary of performance and trends over historical period. Must include SAIFI and SAIDI for all interruptions and all interruptions excluding loss of supply - explain how information has affected DSP	CHP 5 - 5.2.3
Ch5 p12	Realized efficiencies due to smart meters -documented capital and operating efficiencies realized as a result of the deployment and operationalization of smart meters and related technologies. Both qualitative and quantitative descriptions should be provided	CHP 5 - 5.2.4
Ch5 p12-13	Asset Management Process Overview - description of AM objectives/corporate goals and how Dx ranks objectives for prioritizing investments	CHP 5 - 5.3.1
Ch5 p13	Inputs/Outputs of the AM process and information flow for investments; flowchart recommended	CHP 5 -Fig.5-24 & 5.3.1.2
Ch5 p14	Overview of Assets Managed - description of service area (including evolution of features in forecast period affecting DSP), - description of system configuration - service profile and condition by asset type (tables and/or figures) - date data compiled - assessment of degree the capacity of system assets is utilized	CHP 5 - 5.3.2
Ch5 p14-15	Asset Lifecycle Optimization - description of asset lifecycle optimization policies and practices, including asset replacement and refurbishment, maintenance planning criteria and assumptions - description of asset life cycle risk management policies and practices, assessment methods and approaches to mitigation	CHP 5.3.3
Ch5 p15-16	System Capability Assessment for REG - REG applications > 10 kW, number and MW of REG connections for forecast period, capacity of Dx to connect REG, connection constraints	CHP 5 - 5.3.4 and Appendix D in Chapter 5
Ch5 p16	Capital Expenditure Plan Summary for significant projects and activities to be undertaken - capability to connect new load or Gx customers, total annual capex over forecast period by investment category, description of how AMP and Capex planning have affected capital expenditures for each category - list, description and total capital cost of material capital expenditures sorted by category (table recommended) - information related to Regional Planning Process (Needs Assessment Report, Regional Planning Status Letter, Regional Infrastructure Plan - as appropriate) - description of customer engagement - Dx expectations of system development over next 5 years - list, description and total capital cost of projects planned in response to customer preferences, to take advantage of technology based opportunities, to study innovative processes (table recommended)	CHP 5 - 5.4
Ch5 p17-18	Capital Expenditure Planning Process Overview - description of capex planning objectives/criteria/ assumptions, relationship with AM objectives, policy on consideration of non-distribution alternatives, processes used to identify projects in each investment category, customer feedback and impact on plan, method and criteria used to priorities REG investments	CHP 5 - 5.4.1
Ch5 p18	Rate-Funded Activities to Defer Distribution Infrastructure -CDM programs that target distributor-specific peak demand reductions to address a local constraint of the distribution system -demand response programs to reduce peak demand in order to defer capital investment -programs to improve the efficiency of the distribution system and reduce distribution losses -energy storage programs whose primary purpose is to defer specific capital spending for the distribution system	CHP 5 - 5.4.1.1
Ch5 p19-20	Capital Expenditure Summary by Investment Category - completed Table 2 of Ch 5 for historical and forecast period, explanation of markedly different variances plan vs actual, explanation of markedly different variances year over year Table 2 of Ch 5 is provided in Excel format in Appendix 2-AB (must provide actual totals for historical years, as a minimum) - Must also complete Chapter 2 Appendix 2-AA, along with explanations of variances by project or category, the proposed accounting treatments, a statement should be provided that there are no expenditures for non-distribution activities in the applicant's budget	CHP 5 - 5.4.2

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Ch5 p20	Justifying Capital Expenditures -filings must enable OEB to assess whether and how a distributor's DSP delivers value to customers, including by controlling costs in relation to its proposed investments through appropriate optimization, prioritization, and pacing of capital-related expenditures -distributors should also keep pace with technological changes and integrate cost-effective innovative projects and traditional planning needs such as load growth, asset condition and reliability	CHP 5 - 5.4.3
Ch5 p20-21	Overall Plan - comparative expenditures by category over historical period, forecast impact of system investment on O&M, drivers of investments by category, information related to Dx system capability assessment	CHP 5 - 5.4.3.1
Ch5 p21-28	Material Investments - For each project that meets materiality threshold set in Ch 2 p5 - general information - total capital, customer attachments, dates, risks, variances, REG investments - evaluation criteria - may include: efficiency, customer value, reliability, etc. - category specific requirements for each project - system access, system renewal, system service, general plant (as applicable)	CHP 5 - 5.4.3.2 and Appendix A in Chapter 5
EXHIBIT 3 - OPERATING REVENUE		
Load and Revenue Forecasts		
23	Explanation of causes, assumptions and adjustments for volume forecast, including economic assumptions and data sources for customer and load forecasts	3.1.3
23	Explanation of weather normalization methodology	3.1.3
23	Completed Appendix 2-IB; the customer and load forecast for the test year must be entered on RRWF, Tab 10	Appendix 3-4
23 & 24	Multivariate Regression Model - rationale for choice, regression statistics, explanation of weather normalization methodology, sources of data for endogenous and exogenous variables, any binary variables used to either account for individual data points or to account for seasonal or cyclical trends or for discontinuities in the historical data, explanation of any specific adjustments made; data used in load forecast must be provided in Excel format, including derivation of constructed variables	3.1.3 and Appendix 3-1
24 & 25	NAC Model - rationale for choice, data supporting NAC variables, description of accounting for CDM including license conditions, discussion of weather normalization considerations	NA
25	CDM Adjustment - If a distributor expects impacts from any CFF-related projects not deployed by April 2019 but for which a distributor is contractually obligated to complete, or for other programs delivered by the distributor after April 2019, a distributor may include these amounts as part of a CDM manual adjustment to the 2021 load forecast but must ensure that sufficient supporting evidence is provided for all estimated CDM savings	3.1.3 and 3.1.4
25	If a distributor proposes a CDM adjustment to its 2021 load forecast, it should document the CDM savings to be used as the basis for the 2021 LRAMVA threshold. In addition, the allocation of the CDM savings for the LRAMVA and the load forecast adjustment should be provided by customer class and for both kWh and, as applicable to a customer class, kW. The distributor should document its proposal adequately	3.1.3, 3.1.4, and 3.1.5
25	Appendix 2-I - is provided as one approach for calculating the aggregate amounts for the LRAMVA and the corresponding CDM adjustment to the load forecast.	Appendix 3-2
Accuracy of Load Forecast and Variance Analyses		
25	Completed Appendix 2-IB	Appendix 3-4
25 & 26	For customer/connection counts - identification as to whether customer/connection count is shown in year end or average format, year-over-year variances in changes of customer/connection counts with explanation of major changes, explanations of bridge and test year forecasts by rate class, for last rebasing variance analysis between last OEB-approved and actuals with explanations for material differences	3.1.3 and 3.2.1
26	For consumption and demand - explanation to support how kWh are converted to kW for applicable demand-billed classes, year-over-year variances in kWh and kW by rate class and for system consumption overall (kWh) with explanations for material changes in the definition of of or major changes over time (should be done for both historical actuals against each other and historical weather-normalized actuals over time), explanations of the bridge and test year forecasts by rate class, variance analysis between the last OEB-approved and the actual and weather-normalized actual results	3.1.3 and 3.2.1
26	For revenues - calculation of bridge year forecast of revenues at existing rates; calculation of test year forecasted revenues at each of existing rates and proposed rates	3.2.1.13 and 3.2.1.15
26 & 27	With respect to average consumption, for each rate class, distributors are to provide weather-actual and weather-normalized average annual consumption or demand per customer as applicable for the rate class for last OEB approved and historical, weather normalized average annual consumption or demand per customer for the bridge and test years, explanation of the net change in average consumption from last OEB-approved and actuals from historical, bridge and test years based on year-over-year variances and any apparent trends in data	3.1.3 and 3.2.1
Other Revenue		
27	Completed Appendix 2-H	3.3.1 and Appendix 3-5

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27	Variance analysis - year over year, historical, bridge and test	3.3.2
27	Any new proposed specific service charges, or proposed changes to rates or application of existing specific service charges	3.3.3
27	Revenue from affiliate transactions, shared services, corporate cost allocation. For each affiliate transaction, identification of the service, the nature of the service provided to affiliate entities, accounts used to record the revenue and associated costs (Appendix 2-N)	3.3.4
28	Distributors must identify any discrete customer groups that may be materially impacted by changes to other rates and charges	3.3.3
EXHIBIT 4 - OPERATING COSTS		
Overview		
29	Brief explanation of test year OM&A levels, cost drivers, significant changes, trends, inflation rate assumed, business environment changes	4.2.1
Summary and Cost Driver Tables		
29	Summary of recoverable OM&A expenses; Appendix 2-JA	4.2.2 and Appendix 4-1
29	Recoverable OM&A cost drivers; Appendix 2-JB	4.2.3 and Appendix 4-1
29	OM&A programs table; Appendix 2_JC	4.3.1 and Appendix 4-1
29	Recoverable OM&A Cost per customer and per FTE; Appendix 2-L	4.2.2-2 and Appendix 4-1
29	Identification of change in OM&A in test year in relation to change in capitalized overhead.	4.4.4.5
30	OM&A variance analysis for test year with respect to bridge and historical years; Appendix 2-D	4.3.1 , 4.4.4.5 and Appendix 4-1
Program Delivery Costs with Variance Analysis		
30	Completed Appendix 2-JC OM&A Programs Table - completed by program; include variance analysis between test year costs against each of the last OEB approved costs and most recent actuals for variances that are outliers based on historical trend. The variance analysis should explain whether the change was within or outside the applicant's control	4.3.3
30	For each significant change within the applicant's control describe business decision that was made to manage the cost increase/decrease and the alternatives	4.3.1
Workforce Planning and Employee Compensation		
30	Employee Compensation - completed Appendix 2-K	4.4.3 and Appendix 4-1
30	Description of previous and proposed workforce plans, including compensation strategy	4.4.2
30 & 31	Discussion of the outcomes of previous plans and how those outcomes have impacted their proposed plans including an explanation of the reasons for all material changes to headcount and compensation. Explanation for all years includes: - year over year variances, inflation rates used for forecasts, and the plan for any new employees - basis for performance pay, eligible employee groups, goals, measures, and review process for pay-for-performance plans, - relevant studies (e.g. compensation benchmarking)	4.4.3
31	For virtual utilities - Appendix K must also be completed in relation to the employees of the affiliates who are doing the work of the regulated utility. The status of pension funding and all assumptions used in the analysis must be provided. Three or fewer employees - 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.	NA
31	Details of employee benefit programs including pensions, other post-employment retirement benefits (OPEBs), and other costs charged to OM&A. A breakdown of the pension and OPEBs amounts included in OM&A and capital must be provided for the last OEB-approved rebasing application, and for historical, bridge and test years	4.4.4
31	Most recent actuarial report	Appendix 4-3
31	Accounting method for pension and OPEBs; if cash method, sufficient supporting rationale. If proposing to change the basis in which pension and OPEB costs included in OM&A, quantification of impact of transition	4.4.4
Shared Services and Corporate Cost Allocation		
32	Identification of all shared services among affiliates and parent company; identification of the extent to which the applicant is a "virtual utility"	4.5.1
32	Allocation methodology for corporate and shared services, pricing methodology, list of costs and allocators, including any third party review	4.5.1
32	Completed Appendix 2-N for service provided or received for historical, bridge and test; including reconciliation with revenue included in Other Revenue	4.5.1 and Appendix 4-1
32	Shared Service and Corporate Cost Variance analysis - test year vs last OEB approved and test year vs most recent actual	4.5.1 and Appendix 4-1
32	Identification of any Board of Director costs for affiliates included in LDC costs	4.5.1
Non-Affiliate Services, One-Time Costs, Regulatory Costs		
33	Purchased Non-Affiliated Services - file a copy of procurement policy (signing authority, tendering process, non-affiliate service purchase compliance)	4.6.1 and Appendix 4-2
33	For material transactions that are not in compliance with procurement policy, or that were undertaken pursuant to exceptions contemplated within the policy, an explanation as to why as well as a summary of the nature and cost of the product, and a description of the specific methodology used for selecting the vendor	4.6.1
33	Identification of one-time costs in historical, bridge, test; explanation of cost recovery in test (or future years). If no recovery of one-time costs is being proposed in the test year and subsequent IRM term, an explanation must be provided	4.6.2
33	Regulatory costs - breakdown of actual and anticipated regulatory costs, including OEB cost assessments and expenses related to the CoS application (e.g. legal fees, consultant fees), proposed recovery (i.e. amortized?) Completed Appendix 2-M	4.6.3 and Appendix 4-1
33	Information supporting the incremental level of the costs associated with the preparation and review of the current application. In addition, the applicant must identify over what period the costs are proposed to be recovered. For distributors, the recovery period would normally be the duration of the expected cost of service plus IRM term under the Price Cap IR option (i.e. five years). If the applicant is proposing a different recovery period, it must explain why it believes this is appropriate.	4.6.3 and Appendix 4-1

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LEAP, Charitable and Political Donations		
33 & 34	LEAP - the greater of 0.12% of forecasted service revenue requirement or $2,000 should be included in OM&A and recovered from all rate classes	4.7.1
34	Detailed information for all contributions that are claimed for recovery	4.7.1
34	Charitable Donations - the applicant must confirm that no political contributions have been included for recovery	4.7.2
Depreciation, Amortization and Depletion		
34	Explanations for any useful lives of an asset that are proposed that are not within the ranges contained in the Kinectrics Report	4.8.1 and Appendix 4-1
34 & 35	Depreciation, Amortization and Depletion details by asset group for historical, bridge and test years. Include asset amount and rate of depreciation/amortization. Must complete Appendix 2-C which must agree to accumulated depreciation in Appendix 2-BA under rate base	4.8.1 and Appendix 4-1
35	Identification of any Asset Retirement Obligations and associated depreciation, accretion expense	4.8.1
35	Identification of historical depreciation practice and proposal for test year. Variances from half year rule must be documented and supporting rationale provided	4.8.1
35	Copy of depreciation/amortization policy, or equivalent written description; summary of changes to depreciation/amortization policy since last CoS	Appendix 4-9
35	Explanation of any deviations from the practice of depreciating significant parts or components of PP&E separately	4.8.1
35 & 36	For any depreciation expense policy or asset service lives changes since its last rebasing application: - identification of the changes and detailed explanation for the causes of the changes, including any changes subsequent to those made by January 1, 2013 -use of Kinectrics study or another study to justify changes in useful life - list detailing all asset service lives tied to USoA, detail differences in TUL from Kinectrics and explain differences outside of minimum and maximum TUL range from Kinectrics; Appendix 2-BB	4.8.1 and Appendix 4-1
PILs and Property Taxes		
36	Completed version of the PILs model (PDF and Excel); derivation of adjustments for historical, bridge, test years	4.9.1 and Appendix 4-6
36	Supporting schedules and calculations identifying reconciling items	4.9.4
36	Most recent federal and provincial tax returns	Appendix 4-5
36	Financial Statements included with tax returns if different from those filed with application	Appendix 4-5
36	Calculation of Tax Credits; redact where required (filing of unredacted versions is not required)	4.9.3
36	Supporting schedules, calculations and explanations for other additions and deductions	4.9.4
37	Completion of the integrity checks in the PILs Model	4.9.7
37	Accelerated CCA - distributors must bring forward the balance tracked in Account 1592 - PILs and Tax Variances – CCA Changes for review and disposition in its current cost-based rate application, as well as future cost-based rate applications.	NA
38	Explanation of how taxes other than income taxes or PILS (e.g. property taxes) are derived	4.9.5

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Non-recoverable and Disallowed Expenses		
38	Exclude from regulatory tax calculation any non-recoverable or disallowed expenses	4.9.6
Conservation and Demand Management		
38	Statement confirming that costs directly attributable to CDM programs (e.g. staff labour dedicated to such programs) are not included in the revenue requirement to be recovered through distribution rates	4.4.2
40 - 43	LRAMVA - disposition of balance. Distributors must provide version 5 of LRAMVA Work Form (Excel) when making LRAMVA requests for remaining amounts related to CFF activity. An application for lost revenues should include: Participation and Cost reports in Excel format, made available by the IESO An application for lost revenues should also provide: - statement identifying the year(s) of new lost revenues and prior year savings persistence claimed in the LRAMVA disposition - statement confirming LRAMVA based on verified savings results supported by the distributors final CDM Report and Persistence Savings Report (both filed in Excel format). - LRAMVA claim may be based on the information in that report at the time of filing of the application, but it is expected that the claim will be updated when the Final CDM Results Report is issued, and that the approved disposition will reflect the Final Results Report - statement indicating that the distributor has relied on the most recent input assumptions available at the time of program evaluation - summary table with principal and carrying charges by rate class and resulting rate riders - statement providing the disposition period; rationale provided for disposing the balance in the LRAMVA if one or more classes do not generate significant rate riders - details for the forecasted CDM savings included in the LRAMVA calculation including reference to the OEBs approval, or an explanation if there are no forecast CDM savings - rationale confirming how rate class allocations for actual CDM savings were determined by class and program (Tab 3-A of LRAMVA Work Form) - statement confirming whether additional documentation was provided in support of projects that were not included in distributors final CDM Annual Report (Tab 8 of LRAMVA Work Form as applicable) - for a distributor's street lighting project(s) which may have been completed in collaboration with local municipalities, the following must be provided: Explanation of the methodology to calculate street lighting savings; Confirmation whether the street lighting savings were calculated in accordance with OEB-approved load profiles for street lighting projects; Confirmation whether the street lighting project(s) received funding from the IESO and the appropriate net-to-gross assumption used to calculate street lighting savings For the recovery of lost revenues related to demand savings from street light upgrades, distributors should provide the following information: o Explanation of the forecast demand savings from street lights, including assumptions built into the load forecast from the last CoS application o Confirmation that the street light upgrades represent incremental savings attributable to participation in the IESO program, and that any savings not attributable to the IESO program have been removed (for example, other upgrades under normal asset management plans) o Confirmation that the associated energy savings from the applicable IESO program have been removed from the LRAMVA workform so as not to double count savings (for example, if requesting lost revenue recovery for the demand savings from a street light upgrade program, the associated energy savings from the Retrofit program have been subtracted from the Retrofit total) o Confirmation that the distributor has received reports from the participating municipality that validate the number and type of bulbs replaced or retrofitted through the IESO program o A table, in live excel format, that shows the monthly breakdown of billed demand over the period of the street light upgrade project, and the detailed calculations of the change in billed demand due to the street light upgrade project (including data on number of bulbs, type of bulb replaced or retrofitted, average demand per bulb). For the recovery of lost revenues related to demand savings from other programs that are not included in the monthly Participation and Cost Reports of the IESO (for example Combined Heat and Power projects), distributors should provide the following information: The third party evaluation report that describes the methodology to calculate the demand savings achieved for the program year. In particular, if the proposed methodology is different than the evaluation approaches used by the IESO, an explanation must be provided explaining why the proposed approach is more appropriate, the rationale for net-to-gross assumptions used, a breakdown of billed demand and detailed level calculations in live excel format Participation and Cost Reports and detailed project level savings files made available by the IESO to support the clearance of energy- and/or demand-related LRAMVA balances where final verified results from the IESO are not available. These reports should be filed in excel format, similar to the previous Final Verified Annual Reports from 2015 to 2017. o If a distributor seeks to claim any additional program savings to December 31, 2019:	4.10.1 and Appendix 4-10 and 4-11
EXHIBIT 5 - COST OF CAPITAL AND CAPITAL STRUCTURE		
Capital Structure		
43	Statement that LDC adopts OEB's guidelines for cost of capital and confirms that updates will be done. Alternatively - utility specific cost of capital with supporting evidence	5.1.1
43	Completed Appendix 2-OA for last OEB approved and test year	Appendix 5-1
43	Completed Appendix 2-OB for historical, bridge and test years	Appendix 5-2
44	Explanation for any changes in capital structure	5.1.1
Cost of Capital (Return on Equity and Cost of Debt)		
44	Calculation of cost for each capital component	5.1.1
44	Profit or loss on redemption of debt	5.1.1
44	Copies of promissory notes or other debt arrangements with affiliates	Appendix 5-3 and Appendix 5-4
44	Explanation of debt rate for each existing debt instrument	5.1.1
44	Forecast of new debt in bridge and test year - details including estimate of rate	5.1.1
44	If proposing any rate that is different from the OEB guidelines, a justification of the proposed rate(s), including key assumptions	5.1.1
44 & 45	Notional Debt - should attract the weighted average cost of actual long-term debt rather than the current deemed long-term debt rate issued by the OEB	5.1.1
Not-for-Profit Corporations		
45	The requested capital structure and cost of capital (including the proposed cost of long-term and short-term debt and proposed return on equity)	5.2.1
45	Statement as to whether the revenues derived from the return on equity component of the cost of capital is to be used to build up operating and capital reserves or will be used for other purposes	5.2.1
45	If the revenues derived from the return on equity component of the cost of capital will be used to fund reserves, provide the specifications for each proposed reserve fund and a description of the governance (policies, procedures, sign-off authority, etc.) that will be applied	5.2.1

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45	If the revenues derived from the return on equity component of the cost of capital will be used for other purposes, provide a statement as to whether these revenues will be used for non-distribution activities (in the situation where the excess revenues are greater than the amounts needed to fund distribution activities). Provide rationale supporting the use of the revenues in this manner. Also provide the governance (policies, procedures, sign-off authority, etc.) that will be applied to the funding of non-distribution activities	5.2.1
46	If there are approved reserves from previous OEB decisions provide the following: -the limits of any capital and/or operating reserves as approved by the OEB, and identifying the decisions establishing these reserve accounts and their limits -the current balances of any established capital and/or operating reserves	5.2.1
EXHIBIT 6 - REVENUE DEFICIENCY/SUFFICIENCY		
46	Revenue deficiency or sufficiency calculations net of electricity price differentials captured in the Retail Settlement Variance Accounts (RSVAs) and also net of any cost associated with low voltage (LV) charges or DVA balances of distribution expenditures/revenues being tracked through approved deferral and variance accounts for certain distribution assets (e.g. ICM and ACM capital projects, MIST meters) and for which disposition is not being sought in the application.	6.1.1
46	Summary of drivers for test year deficiency/sufficiency, how much each driver contributes; references in application evidence mapped to drivers	6.1.1

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46	Impacts of any changes in methodologies to deficiency/sufficiency	6.1.1
Revenue Requirement Work Form		
47	RRWF - in PDF and Excel. Revenue requirement, def/sufficiency, data entered in RRWF must correspond with other exhibits	Appendix 6-1
47	If the enhanced RRWF cannot reflect a distributor's proposed rates accurately, the distributor must file its rate generator model	6.1.1
EXHIBIT 7 - COST ALLOCATION		
Cost Allocation Study Requirements		
48	Completed cost allocation study using the OEB-approved methodology or a comparable model must be filed reflecting future loads and costs and be supported by appropriate explanations and live Excel spreadsheets. Sheets 11 and 12 of the RRWF must also be completed. Updated load profiles or scaled version of HONI CAIF. Model must be consistent with test year load forecast, changes to customer classes and load profiles.	Appendix 7-2
48	Explanation provided if a distributor is unable to update its load profiles and confirm that it intends to put plans in place to update its load profiles the next time a cost allocation model is filed	7.1.1
49	Provide spreadsheet and a description with example calculations to show how the demand data in the cost allocation model was derived from the load forecast and load profiles	Excel file-NPEI Hydro One data scaled to 2021
49	Description of weighting factors, and rationale for use of default values (if applicable)	7.1.1
49	If using OEB-issued model, hard copy of sheets I-6, I-8, O-1 and O-2 (first page). If using another model, the distributor must file equivalent information. A complete hard copy of the cost allocation model is not required, but the distributor must file a complete live Microsoft Excel cost allocation model, whether using the OEB-issued one or a different model, with the application.	Appendix 7-1
49 & 50	Host Distributor only - evidence of consultation with embedded Dx - statement regarding embedded Dx support for approach to allocation of costs - if embedded Dx is separate class - class in cost allocation study and RRWF, Sheet 11 - if new embedded Dx class - rationale and supporting evidence (cost of serving, load served, asset ownership information, distribution charges); include in cost allocation study and RRWF, Sheet 11 - if embedded Dx billed as GS customer - , include with the GS class in cost allocation model and Appendix 2-P. Provide cost of serving, load served, asset ownership information, distribution charges, appropriateness of rate class. File Appendix 2-Q.	7.1.1
50	Unmetered Loads (including Street Lighting) - Confirmation of communication with unmetered load customers when proposing changes to the level of the rates and charges or the introduction of new rates and charges	7.1.1
50 & 51	microFIT - if the applicant believes that it has unique circumstances which would justify a certain rate, appropriate documentation must be provided	7.1.1
51	Standby Rates - distributors should request approval for its standby rates to be made final and provide evidence confirming that they have advised all affected customers of the proposal. A distributor that seeks changes to its standby charges, including a change in the methodology on which these rates are based, must provide full documentation supporting its proposal, and confirm that all affected customers have been notified of the proposed change(s).	7.1.1
51	New customer class or eliminated customer class - rationale and restatement of revenue requirement from previous CoS	7.1.1
Class Revenue Requirements		

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52	To support a proposal to rebalance rates, the distributor must provide information on the revenue by class that would apply if all rates were changed by a uniform percentage. Ratios must be compared with the ratios that will result from the rates being proposed by the distributor.	7.2.1
Revenue to Cost Ratios		
53	If R:C ratios outside deadband based on model - distributors must include cost allocation proposal to bring them within the OEB-approved ranges. In making any such adjustments, distributors should address potential mitigation measures if the impact of the adjustments on the rates of any particular class or classes is significant.	7.3.1
53	If Cost Allocation Model other than OEB model used - exclude LV, exclude DVA such as smart meters	7.3.1
EXHIBIT 8 - RATE DESIGN		
54	Monthly fixed charges - 2 decimal places; variable charges - 4 decimal places	8.1.1
Fixed Variable Proportion		
54	The following is to be provided in relation to the fixed/variable proportion of proposed rates: -Current F/V with supporting info -Proposed F/V proportion with explanation for any changes (billing determinants from proposed load forecast) -Table comparing current and proposed monthly fixed charges with the floor and ceiling as in cost allocation study Analysis must be net of rate adders, funding adders, and rate riders	8.1.1
Rate Design Policy		
55	Applicants that are still transitioning to fully fixed residential rates should refer to the approach to implementation of the policy, including mitigation expectations, was described in a letter from the OEB published on July 16, 2015	NA
RTSRs		
55	Retail Transmission Service Rate Work Form - PDF and Excel	Appendix 8-2
55	RTSR information must be consistent with working capital allowance calculation	8.3.1
Retail Service Charges		
55	If proposing changes to Retail Service Charges or introduction of new rates and charges - evidence of consultation and notice	NA
55	Distributors that are still using the Retail Service Costs Variance Accounts (RCVAs) will dispose of the balances and the RCVAs will be eliminated. Distributors should forecast retail services revenues based on the updated charges and include the costs of providing retail services in revenue requirement	8.3.2.1
Regulatory Charges		
56	If applying for a rate other than the generic rate set by the OEB, distributors must provide justification as to why their specific circumstances would warrant a different rate, in addition to a detailed derivation of their proposed rate	8.3.3
Specific Service Charges		
56	Specific Service Charge description/purpose/reason for new and revised SSC; calculations to support charges	8.3.5
56	Identification in the Application Summary all proposed changes that will have a material impact on customers, including charges that may affect a discrete group	NA
57	Identification of any rates and charges in Conditions of Service that do not appear on tariff sheet. Explain nature of costs, provide schedule outlining revenues or capital contributions recovered from these rates from last OEB-approved year to 2019 and the revenue forecasted for the bridge and test years. A proposal and explanation as to whether these charges should be included on tariff sheet	NA
57	Ensure revenue from SSCs corresponds with Operating Revenue evidence	3.3.1.1
Wireline Pole Attachment Charge		
56	Record the excess incremental revenue as of September 1, 2018 until the effective date of its rebased rates in a new variance account related to pole attachment charge	8.3.6
57 & 58	Distributors applying for an LDC-specific pole attachment charge must file: - statement confirming the proposed distributor-specific pole attachment charge, the year of data used, effective date - statement discussing main cost drivers for changes to charge including rationale - table summarizing key inputs in calculation, statement confirming that the RRR data (i.e. Account 1830, 5120) and pre-tax weighted cost of capital are consistent with the data filed in other cost of service models - confirmation of the total number of poles and joint use poles in the rate calculation, and a table outlining the rate of pole replacements and percentage of poles depreciated over the past five years - confirmation of the number of attachers that are specific to the distributor's service territory, if a different attacher number than the default number of 1.3 is proposed. A description of the types of attachments on poles, and a discussion of contractual arrangements with other entities that affect the number of attachments, including overlashing attachments, that are counted as part of the LDC's distribution poles - explanation of changes to the hybrid equal sharing allocation rate, if applicable, and the drivers of the proposed change - description of the activities performed by the distributor to directly accommodate third party attachers. Distributors should include a discussion of the methodology, costs and data sources to calculate each component of direct costs. Distributors should show the detailed calculations of total administration and LOP costs, including staff time and labour rates, as applicable - use of utility-specific costs to determine the LDC-specific Power Deduction Factor and LDC-specific Maintenance Allocation Factor applicable to third parties. If a distributor chooses to adopt the default factors in its application for a custom charge, a distributor is still required to complete Table 8 and Table 10-a of the Pole Attachment Workform to substantiate the applicability of the default factors that were used in calculating the provincially approved charge.	NA
Low Voltage Service Rates		

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If the distributor is fully or partially embedded, information on the following must be provided:		
58	Forecast of LV cost, sum of host distributors charges	8.3.7

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58	Low Voltage Cost (historical, bridge, test), variances and explanations for substantive changes	8.3.7
59	Support for forecast LV, e.g. Hydro One Sub-Transmission charges	8.3.7
59	Allocation of LV cost to customer classes (typically proportional to Tx connection revenue)	8.3.7
59	Proposed LV rates by customer class	8.3.7
Smart Meter Entity Charge		
59	Distributor must follow accounting guidance provided on March 23, 2018	8.3.4
Loss Factors		
59	Proposed SFLF and Total Loss Factor for test year	8.4.1
59	Statement as to whether LDC is embedded including whether fully or partially	8.4.1
59	Study of losses if required by previous decision	NA
59	3-5 years of historical loss factor data - Completed Appendix 2-R	8.4.1 and Appendix 8-3
59	If proposed loss factor >5%, explanation and action plan to reduce losses going forward	NA
60	Explanation of SFLF if not standard	NA
Tariff of Rates and Charges		
60	Current and proposed Tariff of Rates and Charges filed in the Tariff Schedule/Bill Impacts Model - **must be filed in Excel format** Explanation and support of each change in the appropriate section of the application	Appendix 8-6 and Excel file
60	Explanation of changes to terms and conditions of service if changes affect application of rates	8.5.1
60	Proposed tariffs must include applicable regulatory charges, and any other generic rates as ordered by the OEB	8.5.1 and Appendix 8-5
Revenue Reconciliation		
60	Calculations of revenue per class under current and proposed rates; reconciliation of rate class revenue and other revenue to total revenue requirement (i.e. breakout volumes, rates and revenues by rate component etc.)	8.1.1.8
60	Completed RRWF - Sheet 13 - rates and charges entered on this sheet should be rounded to the same decimal places as tariff	Appendix 8-1
Bill Impact Information		
61	Completed Tariff Schedule and Bill Impacts Model. Bill impacts must identify existing rates, proposed changes to rates, and detailed bill impacts (including % change in distribution excluding pass through costs - Sub-Total A, % change in distribution - Sub-Total B, % change in delivery - Sub-Total C, and $ change in total bill)	8.5.1, 8.5.2 and Appendix 8-6
61	Impact of changes resulting from the as-filed application on representative samples of end-users (i.e. volume, % rate change and revenue). Commodity and regulatory charges held constant	Appendix 8-6
61	Rates and charges input in the tariff schedule and Bill Impacts Model rounded to the decimal places as shown on the existing tariff	Appendix 8-5 and Appendix 8-6
61	Bill impacts provided for typical customers and consumption levels. Must provide residential 750 kWh, residential at the lowest 10th percentile and GS<50 2,000 kWh. Bill impacts must be provided for a range of consumption levels relevant to the service territory.	8.5.2
61	If applicable, for certain classes where one or more customers have unique consumption and demand patterns, the distributor must show a typical impact and provide an explanation	8.5.2
Rate Mitigation		
62	For distributors still in the process of moving to fully fixed residential rates - evaluation of bill impact for residential customer at 10th consumption percentile. Describe methodology for determination of 10th consumption percentile. File mitigation plan for whole residential class if impact >10% for these customers.	8.5.3 and 8.5.3
62	Mitigation plan if total bill increase for any customer class is >10% including: specification of class and magnitude of increase, description of mitigation measures, justification, revised impact calculation. The Tariff Schedule and Bill Impacts Model must reflect any mitigation plan proposed.	8.5.3
62	Rate Harmonization Plans, if applicable - including impact analysis	NA
EXHIBIT 9 - DEFERRAL AND VARIANCE ACCOUNTS		
63	List of all outstanding DVA and sub-accounts; provide description of DVAs that were used differently than as described in the APH	9.1.2
63	Completed DVA continuity schedule for period following last disposition to present - live Excel format. Continuity schedule must show separate itemization of opening balances, annual adjustments, transactions, dispositions, interest and closing balances for all outstanding deferral and variance accounts. This includes all Account 1508 sub-accounts. A reconciliation of all the Account 1508 sub-accounts to the Account 1508 control account reported in the Electricity Reporting and Record-keeping Requirements	9.1.4 and Appendix 9-1
63	Confirm use of interest rates established by the OEB by month or by quarter for each year	9.1.3
63	Explanation if account balances in continuity schedule differs from trial balance in RRR and AFS	9.1.4
63	Identification of Group 2 accounts that will continue/discontinue going forward, with explanation	9.2.3
63	Statement as to any new accounts, and justification.	9.2.6
63 & 64	Statement whether any adjustments made to DVA balances previously approved by OEB on final basis - the OEB expects that no adjustment will be made to any deferral and variance account balances previously approved by the OEB on a final basis. Distributors to refer to OEB letter of October 2019 in addressing accounting or other errors in respect of Group 1 deferral and variance accounts that have previously been disposed of by the OEB on a final basis. Applicants must provide explanations for the nature and the amounts of adjustments, and include appropriate supporting documentation, under a section titled “Adjustments to Deferral and Variance Accounts”.	9.1.5
64	Breakdown of energy sales and cost of power by USoA - as reported in AFS mapped and reconciled to USoA. Provide explanation if making a profit or loss on commodity.	9.1.6

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64	Completed GA Analysis Workform for each year since the OEB last approved disposition of Account 1589 - Global Adjustment irrespective of whether they are seeking disposition of the Account 1589 – RSVA GA balance as part of their current application. If the distributor is adjusting the Account 1589 balance that was previously approved on an interim basis, the GA Analysis Workform is required to be completed from the year after the distributor last received final disposition for Account 1589.	Appendix 9-2
64	Statement confirming distributor has complied with OEB guidance of February 21, 2019 on the accounting for Accounts 1588 and 1589	9.2.5
64	Completed 1589 Analysis Workform for residual balances that meet the eligibility requirements for dispositions of Account 1595 sub-accounts	Appendix 9-3
Account 1575, IFRS-CGAAP Transitional PP&E Amounts		
64	For applicants that have already rebased under revised CGAAP, but have made further material transitional changes, these impacts should be recorded in Account 1575, and an explanation provided	NA
Retail Service Charges		
65	Retail Service Charges - if material debit or credit balance in 1518 or 1548, distributor must: - confirm variances are incremental costs of providing retail services; identify drivers for balances - provide schedule identifying all revenues and expenses listed by USoA that are incorporated into the variances - state whether Article 490 of APH has been followed; explanation if not followed	9.1.2
65	The OEB established a new variance account for electricity distributors that no longer used the RCVAs. The balance in the account would be refunded to ratepayers in a future rate application, and the new account subsequently closed. Distributors can forecast a balance up to December 31, 2020 or April 30, 2021 and the OEB may consider disposing of the forecasted amount	NA
Disposition of Deferral and Variance Accounts		
65	Identify all accounts for which LDC is seeking disposition; identify DVA for which LDC is not proposing disposition and the reasons why	9.1.2 and 9.2.4
65	Statement whether DVA balances before forecasted interest match the last AFS; explain any variances	9.1.4
65	If the RRR balances do not agree to the year-end balances in the continuity schedule, a distributor must reconcile and explain the difference(s). For any utility specific accounts requested for disposition (e.g. Account 1508 sub-accounts), supporting evidence showing how the annual balance is derived must be provided. The relevant accounting order must also be provided	9.1.4
66	Request final disposition of residual balances for vintage Account 1595 sub-accounts only once. Distributors are expected to seek disposition of the audited account balance in the fourth rate year after the expiry of the rate rider	9.1.2 and Appendix 9-3
66	Proposed mechanisms for disposition with all relevant calculations: - allocation of each account (including rationale) - proposed billing determinants, including charge type, for recovery purposes in accordance with Rate Design Policy	9.2.4
66	Rate riders where volumetric rider is $0.0000 for one or more classes not included in the tariff for those classes	9.2.4
66	Propose rate riders for recovery or refund of balances that are proposed for disposition. The default disposition period is one year; if the applicant is proposing an alternative recovery period must provide explanation	9.2.4
66	Establish separate rate riders to recover balances in the RSVA's from Market Participants who must not be allocated the RSVA balances related to charges for which the MP's settle directly with the IESO	9.2.4
66 & 67	Proposed disposition of Account 1580 sub-account CBR Class B in accordance with the CBR Accounting Guidance. - In the DVA continuity schedule, applicants must indicate whether they serve any Class A customers during the period where Account 1580 CBR Class B sub-account balance accumulated. In the event that the allocated CBR Class B amount results in a volumetric rate rider that rounds to zero at the fourth decimal place in one or more rate classes, the entire balance in Account 1580 CBR Class B sub-account will be added to the Account 1580 – WMS control account to be disposed through the general purpose Group 1 DVA rate riders - Account 1580 sub-account CBR Class A is not to be disposed through rates proceedings but rather follow the OEB's accounting guidance - The DVA continuity schedule will allocate the portion of Account 1580 sub-account CBR Class B allocated to customers who transitioned between Class A and Class B based on consumption levels	9.2.4 and Appendix 9-1
Global Adjustment		
68	Establishment of a separate rate rider included in the delivery component of the bill that would apply prospectively to Non-RPP Class B customers when clearing balances from the GA Variance Account	9.2.4 and 9.2.5
68	GA Analysis Workform in live Excel format for each year that has not previously been approved by the OEB for disposition (on an interim or final basis), irrespective of whether or not seeking disposition of Group 1 deferral and variance account balances. If the distributor is adjusting the Account 1589 GA balance that was previously approved on an interim basis, the GA Analysis Workform is required to be completed from the year after the distributor last received final disposition for Account 1589	Appendix 9-2
68	As part of Note 5 in the GA Analysis Workform, reconciliation of any discrepancy between the actual and expected balance by quantifying differences pertaining to factors such as an outstanding IESO settlement true-up payment. The explanatory items should reduce the discrepancy and provide distributor-specific information to the OEB. Any remaining, unexplained discrepancy will be assessed for materiality and could prompt further analysis before disposition of the balance is approved. Any unexplained discrepancy that is greater than +/- 1% of the total annual IESO GA charges will be considered material and warrant further investigation.	Appendix 9-2
69	Commodity Accounts 1588 and 1589 - confirmation as part of the application that the distributor has fully implemented the OEB's February 21, 2019 guidance effective from January 1, 2019.	9.2.5
69	In order to request for final disposition of historical balances as part of the current application, distributors must provide confirmation that these balances have been considered in the context of the accounting guidance and provide a summary of the review performed. Distributors must also discuss the results of the review, whether any systemic issues were noted, and whether any material adjustments to those balances have been recorded. A summary and description of each adjustment made to the historical balances must also be provided in the application.	9.2.5

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69 & 70	Expectations of final disposition requests of commodity pass-through account balances are: - Some utilities may have received approval for interim disposition of historical account balances or did not request disposition of account balances in a prior rate application due to the threshold test. If these utilities have reviewed the balances in the context of the new accounting guidance and are confident that there are no systemic issues with their RPP settlement and related accounting processes, utilities may request final disposition of account balances. If these utilities identified errors or discrepancies that materially affect the ending account balances, utilities should adjust their account balances prior to requesting final disposition - Utilities that did not receive approval for disposition of historical account balances due to concerns noted should apply the accounting guidance to those balances and adjust the balances as necessary, prior to requesting final disposition. Adjustments to account balances will be considered on a case by case basis.	NA
70	If February 21, 2019 accounting guidance not fully implemented, a distributor must provide an explanation as to why this guidance has not been implemented, the status of the implementation process, and the expected implementation date. In addition, the distributor must complete and submit Appendix A – GA Methodology Description that can be found in the GA Analysis Workform Instructions	NA
70	Certification by the CEO, CFO or equivalent that distributor has robust processes and internal controls in place for the preparation, review, verification and oversight of account balances being proposed for disposition	9.1.1
Establishment of New Deferral and Variance Accounts		
70 & 71	New DVA - information provided which addresses that the requested DVA meets the following criteria: causation, materiality, prudence; include draft accounting order.	9.2.6

Appendix 1-15

There is no Appendix 1-15

Appendix 1-16

OEB Appendix 2-AC-Customer Engagement

File Number:	EB-2020-0040
Exhibit:	1
Tab:	7
Schedule:	1
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Date:	8/31/2020

Appendix 2-AC
Customer Engagement Activities Summary

Provide a list of customer engagement activities	Provide a list of customer needs and preferences identified through each engagement activity	Actions taken to respond to identified needs and preferences. If no action was taken, explain why.
Residential & Small Commercial Exploratory Customer Focus Groups On June 26, and 27th, 2019, NPEI held 4 focus groups, each moderated by Innovative Research Group. 2 focus groups were held in Niagara Falls, and 2 focus groups were held in Lincoln.The focus groups were divided, one with a group of residential customers, one with a group of small business customers. In total, 33 customers attended the focus groups. The objective was to obtain insights into what customers expect of NPEI particularly in terms of what represents value to customers and what customer priorities for NPEI are, both in context of valued outcomes and choices impacting customers.	Customers identified, and ranked the following priorities they wanted NPEI to focus on in its upcoming plan: • Price/Cost Efficiency • System Maintenance/Reliability • Greening the Grid/Microgeneration • Need for Education • Customer Service/Tools • Supporting Local Community/Small Business • Planning for Growth/Increased Demand • Preparing System for Climate Change	The priorities discussed by NPEI customers in the focus groups were developed into themes to be tested amongst a larger group of customers in online and telephone reference surveys: • Delivering electricity at reasonable distribution rates • Finding internal efficiencies and ways to find cost savings • Ensuring reliable electrical service • Proactively replacing aging infrastructure that is beyond its useful life • Providing tools and services that allow customers to better manage their electricity usage • Providing quality customer service and enhanced communications • Support the local economy and community groups through new incentives programs • Upgrading the electrical system to better respond to and withstand the impact of adverse weather
Telephone and Online Reference Surveys Telephone surveys were fielded from July 9th to 26th, 2019 amongst a random sample of 500 residential, and 87 small business customers. Online Surveys were fielded from July 12th to 29th 2019 amongst 939 residential and 71 small business customers. The survey focused on understanding the gap between the services and experience customers want and the services and experience customers are receiving, and on customer views about the outcomes the utility should focus on, priorities among those outcomes, and trade-offs illustrated by choices on specific programs or the pacing and prioritization of investments.	• Customers don't expect NPEI to just focus on one outcome. • Among competing outcomes, price, reliability, and finding internal cost efficiencies are the top three priorities for both residential and small business customers. When ranked relative to other priorities, NPEI customers see price as the top outcome that the utility should focus on. • While keeping price at a reasonable and affordable level is an important priority for customers, the majority feel that investing in the grid to maintain reliability, is preferable to deferring investments to keep bills low. • Residential and small business customers have consistent priorities when it comes to reliability. Reducing the overall number of outages, the overall length of outages, and improving restoration time are the top three priorities for both rate classes. • The majority of residential and small business customers are supportive of NPEI making investments in aging infrastructure in order to maintain reliability, even if that results in small rate increases • The majority of residential and small business customers are willing to consider paying more to invest in maintaining reliability, equipping staff with equipment and IT systems, proactively investing in system capacity, and modernizing the grid knowing that it could eventually save money.	A draft plan was developed that identified 7 investment areas where pacing could be accelerated, or slowed down, based on customer needs and expectations. The plan was developed this way so more specific customer feedback could be obtained through an online workbook before finalizing spending decisions. The 7 investment areas were: • Underground Cable Replacement • Overhead Pole Replacement • Overhead Transformer Replacement • Grid Modernization • Converting Outdated Underground Kiosk Transformers • Subdivision Underground Rehabilitation • Overhead Rebuilds
Online Workbook Survey (residential, small commercial, and large commercial customers) An Online Workbook/Survey was created and made accessible for all NPEI customers from November 21st to December 17th, 2019, and customers were offered the chance to win a $500 cash prize. The workbook was developed using feedback already received through the Exploratory Customer Focus groups, and Telephone and Online Reference Surveys. The workbook was designed to both educate customers on NPEI's role in the electricity system and its draft business plans, as well as to gather feedback on trade-offs between seven specific investments. Tailored workbooks for Residential, Small Business, and GS>50 kW were deployed to all customers with an email address on file, as well as promoted through a generic link on NPEI's website. In total 1,488 residential, 65 small business, and 32 large commercial customers who represent 74 unique accounts, completed the workbook.	• Overall, NPEI's customers were supportive of its 2021-2025 draft plan as it was presented during the customer engagement process. In each of the three workbooks (Residential, Small Business and GS > 50 kW), the majority of customers surveyed indicated a preference for NPEI to either maintain the proposed rate increase to deliver a program that focuses on the priorities of its draft plan, or to improve service even if that means an increase that exceeds what is proposed in the draft plan. • The customer support for maintaining the proposed level of rate increase included in the draft plan was greater than the customer support for improving service even if that means an increase that exceeds what is proposed in the draft plan. • Specific attention has been paid to how those whose electricity bill has a significant impact on their households' (or business') finances opinions vary from the broader customer base. Reflecting their financial capacity, those who agree that their electricity bill has a significant impact on their household's finances are less supportive of investments than the average customer but still generally support NPEI's draft plan and the associated impacts. Among Vulnerable Residential customers, only a minority (29%) indicated that NPEI should keep increases below what is proposed in the draft plan.	In determining whether to adjust the overall level of spending proposed in its draft plan, NPEI has considered the following factors: • Balancing customer preferences in general against the preferences expressed by the more vulnerable Residential customers. • The resulting level of bill impacts to all customer classes. • Internal resource constraints: whether or not an increase in the overall level of proposed capital projects or programs may require additional engineering or operations resources beyond NPEI's current staffing levels. • Financial leverage: whether or not an increase in the overall level of proposed capital projects or programs may require NPEI to incur additional debt. Based on the above considerations, NPEI has decided to maintain the overall proposed level of capital spending consistent with what was included in the draft plan.

Provide a list of customer engagement activities	Provide a list of customer needs and preferences identified through each engagement activity	Actions taken to respond to identified needs and preferences. If no action was taken, explain why.
Online Workbook Survey - Overhead Pole Replacement A recent asset health condition assessment shows that 575 or approximately 3% of the poles in NPEI's distribution system are in poor or very poor condition. Each year, new poles enter this condition, and NPEI takes an approach that proactively replaces poles as to not create a large backlog. As a general rule, pole failure only causes an outage when something happens outside of the utility's control, most frequently due to trees knocking them down or a motor vehicle accident. On average, since 2014, NPEI has replaced approximately 88 poles per year. This pace has effectively maintained reliability over this period. NPEI is proposing to replace most of these 575 poles in poor and very poor condition over the course of the next five years, however, there is an opportunity to replace these poles more quickly or slowly. NPEI must continue to invest in overhead pole replacement, therefore, this is a matter of whether customers would rather pay more during the upcoming period, or push some level of investment beyond the next five years.	Among Residential customers, a plurality (47%) indicated a preference for an accelerated pace, while among Vulnerable Residential customers, a plurality (43%) indicated a preference for a slower pace than what was proposed in the draft plan. Among Small Business Customers, a majority (56%) indicated a preference for an accelerated pace. Of the GS>50 kW respondents, 15 of 32 indicated a preference for the pace that was included in the draft plan.	In considering the overall customer preferences from each rate class, as well as the specific preferences of the more vulnerable Residential customers, NPEI has decided to maintain its proposed plan for Overhead Pole Replacement.
Online Workbook Survey - Overhead Transformer Replacement A recent asset health condition assessment shows that 1,251 or approximately 21% of the overhead transformers in NPEI's distribution system are in poor or very poor condition. Since 2014, overhead transformer failure has directly resulted in approximately 15 outages per year. That said, in most cases, when an overhead transformer fails, it only impacts a small amount of customers and the equipment can be replaced within 2-3 hours depending on the circumstances. However, when these outages do occur, it can take NPEI crews an extended period of time to replace the cable and restore power to affected households and businesses. NPEI is proposing a new program to proactively replace 250 of the 677 or 37% of the overhead transformers identified as very poor condition before they fail over the course of the next five years. As with distribution poles, NPEI will proactively invest in overhead transformer replacement, therefore, this is a matter of whether customers would rather pay more during the upcoming period, or push some level of investment beyond the next five years.	Among Residential customers, a plurality (47%) indicated a preference for an accelerated pace, while among Vulnerable Residential customers, a plurality (38%) indicated a preference for a slower pace than what was proposed in the draft plan. Among Small Business Customers, a majority (53%) indicated a preference for an accelerated pace. Of the GS>50 kW respondents, 14 of 32 indicated a preference for an accelerated pace and 12 of 32 indicated a preference for what was included in the draft plan.	Although there is an apparent overall preference for an accelerated pace, Vulnerable Residential customers prefer a slower pace. In addition, the majority of Residential and GS>50 kW customers preferred either the draft plan or slower pace. Therefore, NPEI has decided to maintain its proposed Overhead Transformer Replacement.
Online Workbook Survey - Converting Outdated Underground Kiosk Transformers NPEI's system features a type of underground transformer that was popular in the 1940s to 1970s which no longer meets construction and safety standards. While this equipment still functions, it is becoming increasingly difficult to safely and effectively maintain. When this equipment does fail, it can result in lengthy outages due to the limited accessibility due to the original method of construction. On average, since 2014, NPEI has converted approximately 9 kiosk transformers per year. Between 2018 and 2019, the pace of this program was slowed due to an increase in system access customer demand projects, and today, there remains 75 transformers in need of replacement. NPEI is proposing to convert all of this equipment within the next seven years, with 55 being converted in the next five year period. That said, there is an opportunity to convert these kiosk transformers more slowly.	Among Residential customers, a majority (56%) indicated a preference for the pace that was included in the draft plan, while among Vulnerable Residential customers, a strong majority (73%) indicated a preference for either a reduced pace, or an even slower pace. Among Small Business Customers, a majority (60%) indicated a preference for the pace that was included in the draft plan. Of the GS>50 kW respondents, 21 of 32 indicated a preference for the pace that was included in the draft plan.	Although there is an apparent overall preference for the pace that was included in the draft plan, 73% of Vulnerable Residential exhibited a preference for a reduced pace or an even slower pace. In response, NPEI has reduced the proposed Conversion of Outdated Underground Kiosk Transformers Program from replacing 11 units per year to 8 units per year, resulting in a reduction of $242,000 in the test year capital plan.
Online Workbook Survey - Underground Cable Replacement Many neighbourhoods across NPEI's service territory are serviced by underground cables. Historically, NPEI has taken a "run-to-failure" approach with this equipment; that is, a cable will be replaced only once it has failed. The age of this equipment is now becoming a concern, with approximately 78 km or 18% of underground cable operating beyond its estimated useful life of 35 years. Since 2014, underground cable failure has directly resulted in approximately ten outages per year, and when these outages do occur, it can take NPEI crews an extended period to replace the cable and restore power to affected households and businesses. Between 2021 and 2025, NPEI is proposing a new program that will replace cable that has been identified as past end of life when completing other associated work. NPEI believes that this could help reduce the number and length of outages caused by underground cable failure, as well as to start getting ahead of the ongoing age issue. That said, there is an opportunity to take a more proactive approach to addressing some of the older cable in the system.	Among Residential customers, a majority (65%) indicated a preference for an accelerated pace, or an even further accelerated pace, while among Vulnerable Residential customers, a majority (58%) indicated a preference for an accelerated pace, or an even further accelerated pace. Among Small Business Customers, a majority (68%) indicated a preference for an accelerated pace, or an even further accelerated pace. Of the GS>50 kW respondents, 16 of 32 indicated a preference for the pace that was included in the draft plan, 14 of 32 indicated a preference for an accelerated pace and 2 of 32 preferred a further accelerated pace	In response to the overall preference amongst all customer types for an accelerated pace or an even further accelerated pace, NPEI has increased the level of its Underground Cable Replacement Program. In order to maintain the overall level of proposed capital spending, NPEI has increased the proposed Underground Cable Replacement budget by $242,000, which corresponds to the reduction made to the Conversion of Outdated Underground Kiosk Transformers Program. This proposed increase will allow NPEI to proactively replace approximately 0.3 km of additional underground cable annually.

Provide a list of customer engagement activities	Provide a list of customer needs and preferences identified through each engagement activity	Actions taken to respond to identified needs and preferences. If no action was taken, explain why.
Online Workbook Survey - Subdivision Underground Rehabilitation 71 of the subdivisions in NPEI's service territory were constructed with direct buried cable which refers to a type of construction where cables are laid directly in underground trenches without a protective barrier. While this was typical construction at the time, 40 of these subdivisions were built 40 or more years ago, and the cables are now approaching the end of their recommended life. In this upcoming plan, NPEI is proposing a new program to start preparing to upgrade the service in the subdivisions with the most pressing needs. In order to keep costs down, NPEI is proposing to start rehabilitation of the underground "system" by installing ducts that will eventually carry underground cables over the next five years. The cables would be installed as needed (upon failure) or once all of the old subdivisions have had the duct installed. Completing this work in two phases will not only save costs now, but also help ensure that NPEI will be able to rehabilitate the most subdivisions in the shortest time. Between 2021 and 2025, NPEI is proposing to proactively install ducts in approximately 10 subdivisions. Which subdivisions receive investment first will predominantly be based on age. That said, there is an opportunity to either accelerate or slow down the pace of this new program.	Among Residential customers, a plurality (45%) indicated a preference for the pace that was included in the draft plan, while among Vulnerable Residential customers, a plurality (45%) indicated a preference for a slower pace. Among Small Business Customers, a majority (52%) indicated a preference for the pace that was included in the draft plan.Of the GS>50 kW respondents, 14 of 32 indicated a preference for a slower pace.	In considering the overall customer preferences from each rate class, as well as the more vulnerable Residential customers, NPEI has decided to maintain its proposed plan for Subdivision Underground Rehabilitation.
Online Workbook Survey - Overhead Rebuilds Beyond replacing overhead poles, NPEI has a program that rebuilds the overhead system for entire streets and neighbourhoods. This includes poles, wires, and all other equipment that goes into operating the overhead system. A recent asset health condition assessment identified a total of 60 areas within NPEI's service territory that require complete overhead rebuilds. Most of this equipment is either beyond its recommended age or deteriorated due to weather and other factors. This infrastructure is in addition to the poles identified in the earlier section. This program is intended to contribute to the "betterment" of the overhead system by; •Improving system performance by installing animal guards and higher capacity transformers to reduce the likelihood of outages, and; •Improving system aesthetics with new and taller poles. On average, each of the projects would replace approximately 30-40 poles, depending on the population density of the area being worked on. NPEI's draft plan would rebuild 40 out of 60 areas in the 2021 to 2025 period. NPEI must continue to invest in overhead rebuilds, therefore, this is a matter of whether customers would rather pay more during the upcoming period or push some level of investment beyond the next five years.	Among Residential customers, a narrow majority (50%) indicated a preference for the pace that was included in the draft plan, while among Vulnerable Residential customers, a plurality (39%) indicated a preference for the pace that was included in the draft plan. Among Small Business Customers, a plurality (45%) indicated a preference for the pace that was included in the draft plan. Of the GS>50 kW respondents, 19 of 32 indicated a preference for the pace that was included in the draft plan.	Due to the agreement of overall customer preferences for the pace that was included in the draft plan, NPEI has decided to maintain its proposed plan for Overhead Rebuilds.
Online Workbook Survey - Grid Modernization New technology has changed the way that NPEI can manage and monitor the distribution system. Supervisory Control and Data Acquisition (SCADA) systems allow NPEI staff the ability to remotely monitor and trace system faults and re-close switches from a control room rather than sending a repair crew to patrol the lines. These systems are particularly effective where there are larger distances between customers, for instance, in more rural areas of the western region of NPEI's service territory. This equipment can have significant positive impacts on restoration times when an outage does occur, particularly in instances such as during a severe weather event. On average, since 2014, NPEI has installed approximately two remote devices per year, with focus on more rural, lower density areas. That said, there is an opportunity to install this monitoring and control equipment more quickly or slowly.	Among Residential customers, a plurality (44%) indicated a preference for the pace that was included in the draft plan, and among Vulnerable Residential customers, a plurality (38%) also indicated a preference for the pace that was included in the draft plan. Among Small Business Customers, an equal number (41%) indicated a preference for the pace that was included in the draft plan as those who indicated a preference for an accelerated pace. Of the GS>50 kW respondents, 14 of 32 indicated a preference for the pace that was included in the draft plan and 12 of 32 indicated a preference for an accelerated pace.	Due to the agreement of overall customer preferences for the pace that was included in the draft plan, NPEI has decided to maintain its proposed plan for Grid Modernization.
Online Workbook Survey - Commercial GS>50 kW Rate Design Currently, distribution rates for the GS>50 kW rate class are split on a 15% fixed and 85% variable rate basis. In order to improve cost certainty, some customers have expressed a desire to move to a more fixed distribution rate. In its current draft plan, NPEI is proposing a fixed portion of the distribution charge of 21.5% and a variable charge of 78.5%. Not only does this create more cost certainty for customers, but it also provides revenue certainty for NPEI to operate and maintain the distribution system. For customers who have predictable electricity usage habits, this change likely wouldn't have much of an impact, while creating more certainty for those whose electricity usage fluctuates more regularly.	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 Results of the survey for this question were as follows: • Status Quo – 11 in favour • Included in Draft Plan – 20 in favour • Higher Fixed Distribution Charge – 1 in favour	NPEI is proposing a fixed/variable split of 21.5% fixed and 78.5% variable as calculated in the 2021 Cost Allocation model using the Minimum System with PLCC Adjustment similar to the 2015 Cost of Service rate application and consistent with the results from NPEI's customer engagement.

Provide a list of customer engagement activities	Provide a list of customer needs and preferences identified through each engagement activity	Actions taken to respond to identified needs and preferences. If no action was taken, explain why.
Public Safety Survey In 2016 and 2018, NPEI engaged a third party to conduct a bi-annual survey to assess public safety awareness of the risks associated with electricity. NPEI reviews the results of these surveys closely.	NPEI scored an 84% Public Safety Awareness Index score in 2016. This decreased by one per cent in 2018 when NPEI scored an 83%. There were improvements in awareness in some key areas, including: • The importance of calling for an underground locate (56.6% definitely would call in 2016 versus 62.2% definitely would call in 2018) • Impact of touching an overhead power line (92.6% said it was very dangerous in 2016 versus 95.9% said it was very dangerous in 2018) • Proximity to a downed power line (78% said to stay at least 10 meters away in 2016 versus 81.3% said to stay at least 10 meters away in 2018) There were decreases in awareness in a couple of areas, including: • Proximity to an overhead power line (20.7% were aware they needed to remain 3-6 meters away from an overhead power line in 2016 versus 18.6% in 2018) • Danger of tampering with electrical equipment (90.7% said it was very dangerous in 2016 versus 86.7% in 2018) • What to do if a power line falls on your vehicle when you are inside (90% said stay in your car until the hydro could be turned off in 2016 versus 86.9% in 2018)	To improve customer awareness of electrical safety, starting in 2017, NPEI in partnership with other GridSmartCity co-operative members, developed a series of six safety videos featuring Lucky the Squirrel, a squirrel who finds himself getting into trouble because he isn't aware of the hazards of electricity and what he can do to ensure he stays safe in the future. Lucky helps people learn about the importance of calling for a free underground cable locate before you dig, limits of approach for both overhead and downed power lines, what to do if a power line falls on your car, and the dangers of equipment inside padmount transformers and on a power line. Forty-five utilities and the ESA partnered on the development of the videos, helping to keep costs low and amplifying the messages across Ontario. The videos are used in NPEI's electrical safety school program, which is delivered at no charge to Grade 5 and 6 students each year in NPEI's service territory. In 2018, it was a priority for NPEI to improve safety communication efforts. NPEI as a member of the GridSmartCity co-operative, supplemented the standard safety questions with extra questions to discover where the public finds information related to electrical safety and how many actively speak to their children about electrical safety. This revealed that 20.2% of survey respondents had school-aged children and of that 20.2%, only 57.1% claimed to have had conversations with their children about electrical safety. The inclusion of the supplementary questions supplied by the GridSmartCity Communications Committee revealed that 63% of respondents get their electrical safety information online, either from searches (29.9%) or from their local electricity distributor website (33.1%). NPEI used this information to enhance its power outage pages to include links to safety information and the videos.
Customer Transactional Survey As a way to evaluate and ensure quality customer service, NPEI attaches a short, customer satisfaction survey to all email correspondences it has with customers. This survey is a way to collect feedback about the service a customer recently received and to provide them with an opportunity to add additional comments or suggestions.	The survey helps to identify and track trends in customer needs and preferences, and once analyzed, NPEI's Customer Service department staff review the replies in order to take any action that may be required. Certain comments or concerns are followed up on with the customers if they have chosen to identify themselves or ask to be contacted. NPEI regularly receives positive feedback from this survey. This includes: • Praising specific Customer Service Representatives or Linemen for their work. • The effectiveness of informative communications sent out to customers. • General praise for NPEI as a company and the work being done by staff as a whole. Some of the main concerns NPEI heard about from customers through this survey were: • The NPEI My Account portal is not user-friendly and customers do not enjoy using it with its current look and feel. • The need to make it easier to transition from the e-bill email notification to the website and to view the bill online. • The need for more education for customers in regards to how the bill is calculated and billed, and how electricity is transmitted. • The cost of electricity.	From these concerns, NPEI has undertaken the following to improve Customer Service in these areas: • NPEI launched a new online customer portal on February 10, 2020 called Customer Connect, as an upgrade to the current My Account portal (more information below). • In 2019 NPEI developed a new informational handout to educate customers on the bill breakdown and how prices are determined. Generation, transmission and local distribution are outlined to give customers a better understanding of these costs and who is responsible for each. It also defines the portion of each bill that NPEI retains, and the amount that is distributed to different companies and government agencies. • NPEI's Communications Coordinator receives an email notification when a Google review is posted. This staff member follows up with the Customer Service department if any follow-up is required. • As part of the 2020 Customer Engagement Plan, NPEI will explore options to create a series of informational and instructional videos to be featured on the NPEI website, social media, and YouTube. The videos will cover topics such as safety, conservation, how to view/pay your bill online, and more.
Updating My Account Online My Account provided customers with online resources to manage their electricity consumption and view usage, view and print current and past bills and view current bill amounts. The portal was launched on the precipice of a postal strike in June 2011 and provided customers with an alternative means to access their account and billing information. In the years since My Account was launched, over 21,000 customers have signed up for the online portal.	Through the Customer Transactional Survey, NPEI has heard from customers over the past few years that *My Account* had become very outdated and customers wanted an updated, refreshed version of *My Account*. They wanted the platform to be more user friendly and to have increased functionality. In the Customer Service Transactional Survey, 77 out of the 289 comments received since 2017 were regarding the old *My Account* service and expressed a desire for an update.	NPEI developed and went live with an updated *My Account* Portal called *Customer Connect* in February 2020. Customer Connect is a new and updated online portal that gives customers more ease of use. Improved self-serve functions will allow customers to update and manage their billing and account information without the need to contact or visit the NPEI office. With a new user-friendly interface, customers will be able to keep track of their bills and manage their consumption and usage in a more straightforward and less complicated manner. Customer Connect puts customer security and privacy as a top priority, with end-to-end encryption as well as user authentication and time-outs to ensure that only authorized users obtain access, which means both customer and utility information remain protected and secure. Features of Customer Connect that build upon the existing features of My Account include: • New Service Connection Set Up • Move/Transfer Premises • Pay Now • Request a Service Call • Display Billed Demand and kWh Usage • Enhanced display of bill history and transaction history

Provide a list of customer engagement activities	Provide a list of customer needs and preferences identified through each engagement activity	Actions taken to respond to identified needs and preferences. If no action was taken, explain why.
Bi-Annual Customer Satisfaction Survey On a bi-annual basis, NPEI engages a third party to survey its customers to assess customer satisfaction with the service NPEI provides and tracks the results year over year to analyze trends and determine where improvement is needed.	NPEI consistently exceeds industry, national and provincial standards in many key areas. In 2019, NPEI conducted their most recent survey with a third party to gauge customer satisfaction. NPEI scored higher than the provincial and national average in all categories: • Customer Satisfaction: Initial 96% • Customer Satisfaction: Post 95% • Communication Score 82% • Overall Satisfaction with the most recent experience 84% • Convenience of Services Score 82% • Customer Experience Performance Rating (CEPr) 88% • Customer Centric Engagement Index (CCEI) 87% • Credibility & Trust Index 88% • UtilityPulse Report Card A	While NPEI is very pleased with these results, we realize that customer expectations are constantly evolving. In order to maintain high scores, NPEI will need to take a proactive approach in improving communications and maintaining service and reliability standards. Website enhancements including mobile optimization, increasing customer self-service options, and improving outage communications are important priorities for NPEI. Customer feedback will continue to be gathered on an ongoing basis through various surveys so that NPEI is able to respond quickly to changing customer preferences. As well, NPEI will continue to maintain and upgrade its existing infrastructure to ensure power outages are resolved quickly and customers continue to experience reliable service.
Community Events As the local hydro provider, NPEI places great importance on being actively involved in the various communities they service. Participating at home shows, Touch a Truck events, and other community activities is a key customer engagement tool in which NPEI is able to meet and engage with customers that may not have had the opportunity to make contact with the office.	During these events, staff are able to communicate with customers about things they may not have previously heard about, such as new services, billing changes, low income support programs, safety awareness and energy-efficiency best practices. The events also provide an opportunity for NPEI to obtain and respond to customer feedback, and report back to the office with ideas for customer service and communication improvements.	NPEI employees receive lots of feedback during community events. If a customer specifically requests a follow-up, NPEI staff will ensure that a staff member reaches out to the customer to make sure they get the information they are looking for. Because these face-to-face interactions are so well received, NPEI is exploring opportunities to participate in more community events in the coming years.
Public Information Nights In 2018 NPEI held a Public Information Night to provide information on the planned capital project to install ducts within the Rolla Woods subdivision. The meeting was coordinated with the City of Niagara Falls, who were also planning roadwork within the same area. NPEI presented the proposed designs and provided a full explanation of the project plans in order to obtain feedback from property owners in attendance.	A total of 27 participants attended. The general feedback received was positive and NPEI encouraged property owners to contact the office with any concerns that may arise throughout the duration of the project. Customers indicated that the format of the event worked well, and they appreciated the opportunity to discuss the project with NPEI staff in person.	As a result of the positive customer feedback regarding the style of this event, NPEI will continue to offer Public Information Nights. The NPEI engineering department is currently working with the Town of Lincoln to coordinate an event in Q2 of 2020 for the Jordan underground rebuild project.

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Appendix 1-17

Customer Engagement Strategy

Customer Engagement Strategy Communications Plan

Objective:

- To improve energy literacy for customers in the following topics
    - Electricity rates, pricing and understanding your bill
    - Rules and rights governing Niagara Peninsula Energy customer relationships
    - Safety
    - The value Niagara Peninsula Energy Inc. adds to the community
- To help customers understand Niagara Peninsula Energy's Distribution System Plan and how it fits into the Corporation's strategic objectives of NPEI.
- To understand the needs and priorities of our customers to ensure NPEI is meeting their expectations with respect to reliability and customer service offerings.

Tactics:

- 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. Ask people to include their postal codes so we can better identify the feedback that comes from our customer base.
- Small focus groups/face-to-face meetings
    - Large customer sessions
    - Connect with Niagara Peninsula Energy in Niagara Falls, Lincoln, West Lincoln and Pelham
- Use internal videos on social media and website to profile some of the work done in house
- Implement a safety poster contest, contest will be for three different age groups for school age children in Grades 1 to 8.
- Educate, inform and promote: innovation, energy literacy, energy conservation and why it is important, safety, industry and company news.

Success Measurement:

- Survey responses
- Attendance at events
- Feedback on transactional surveys
- Participation in Twitter chats
- Number of contest entries

Engagement Marketing Plan

Objectives:

Phase 1:

1. To raise awareness that Niagara Peninsula Energy is reaching out to customers with surveys and in focus groups to get feedback on what is important to them when it comes to NPEI business decisions
2. To make customers feel empowered and want to participate in the surveys and focus groups.

Phase 2:

1. To provide customers with the results of the outreach efforts and NPEI's response so they understand that Niagara Peninsula Energy underwent a comprehensive research effort, carefully assessed and weighed the feedback, and responded accordingly.
   The intention of Phase 2 is to lay the foundation for ongoing outreach efforts by helping customers understand that Niagara Peninsula Energy takes customer engagement and feedback seriously, and applies it to make business decisions that align with our customers' needs, wants and preferences.

Audiences:

Phase 1:

- All Residential customers
    - Testing focus groups
    - Online workbook
    - Low-volume focus group
    - Telephone surveys
- All business customers
    - GS < 50 kW
        - Testing focus groups
        - Online workbook
        - Low-volume focus groups
        - Telephone surveys
    - GS > 50 kW
        - Online workbook

Phase 2:

- All residential customers
- All small business customers
- All GS< 50 kW customers

Key Messages:

Phase 1:

Help Niagara Peninsula Energy make the business decisions that matter to you!

In 2020, we will be submitting our multi-year capital plan to the Ontario Energy Board, and we want to make sure that the decisions we make reflect what matters to you, our customer and rate payer.

Our goal is to get as much feedback from our customers as possible and use it to feed our business plans and objectives for the future.

Sub-message:

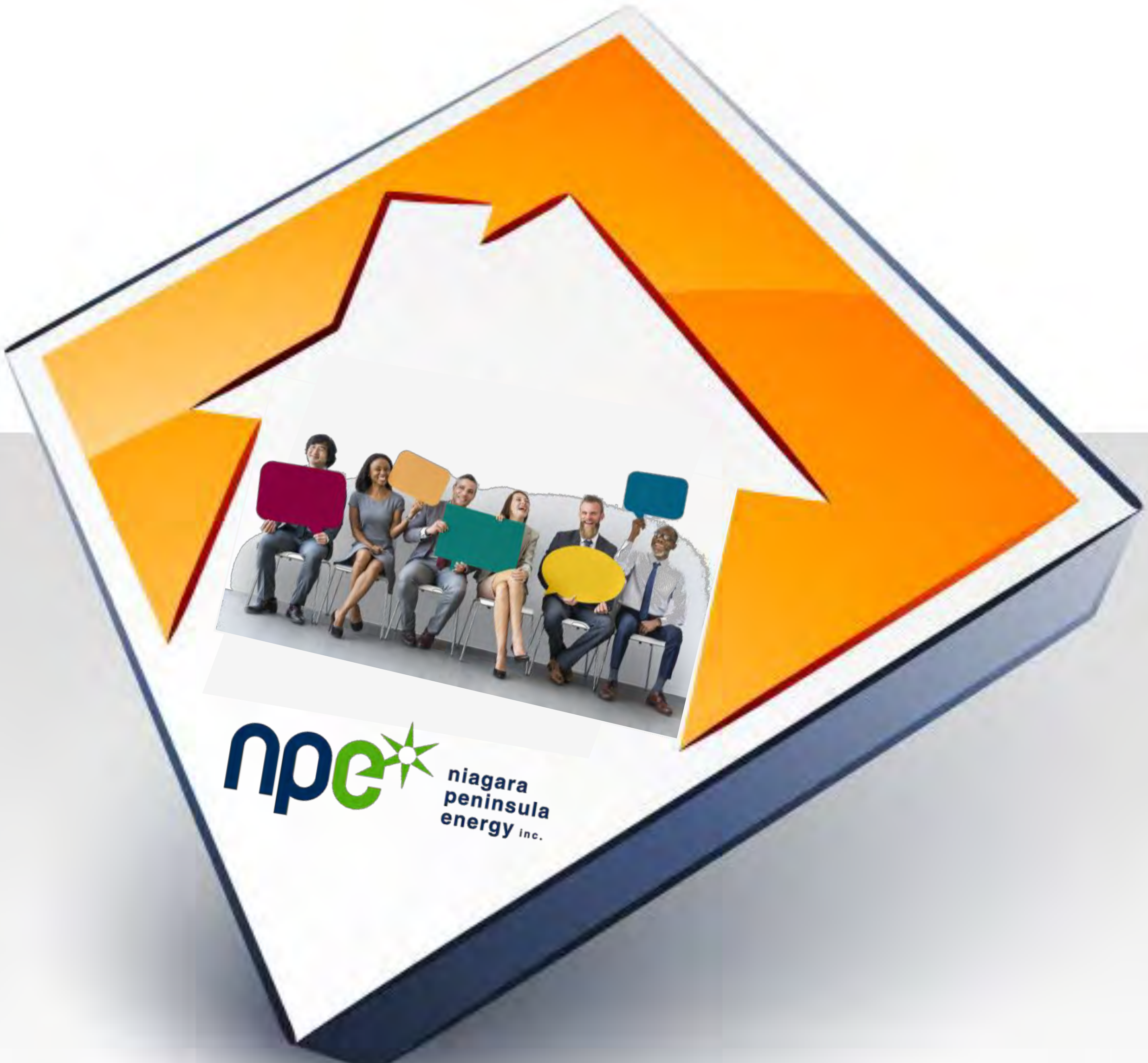
Not all decisions will be popular, but they may be necessary. We are committed to making sure you understand the factors that go into our business decisions, and how we take your priorities into consideration.

Appendix 1-18

Customer Satisfaction Survey Results 2019 and 2017

Niagara Peninsula Energy Inc.

2019 Electric Utility Customer Satisfaction Survey



UtilityPULSE

The purpose of this report is to profile the connection between Niagara Peninsula Energy Inc. (NPEI) and its customers.

The primary objective of the Electric Utility Customer Satisfaction Survey is to provide information to support discussions about improving customer care at every level in your utility.

The UtilityPULSE Report Card® and survey analysis contained in this report is intended to capture the state of mind or perceptions about your customers' need and wants – the information contained in this report will help guide your discussions for making meaningful improvements.

All comments and questions should be addressed to:

Sid Ridgley, UtilityPULSE division, Simul Corporation

Toll free: 1-888-291-7892 or   Local: 905-895-7900

Email: sridgley@simulcorp.com

Feedback, Information & Insights

In the spring of 2017, customers were very angry about the quickly increasing costs of electricity over the previous 5 or more years. In fact, some years were double-digit increases while wages and inflation hovered around the 2% mark. We know customers were upset because the number of survey respondents in the Ontario benchmark survey who said paying their bill was ‘often a problem’ grew from 11% [2014] to 18% [spring 2017] and the number of At Risk customers grew from 10% to 22% [spring 2017].

Data from the Niagara Peninsula Energy Inc. (NPEI) and Ontario benchmark surveys show the level of “anger” has dramatically reduced. Whether changes in perception were created by the Liberal Government’s Spring 2017 reduction by 25% in electricity prices, or the change to a Conservative government June 2018, or the promise of further reductions in electricity prices, or improvements in the economy, or increases in real pay, or improvements that LDCs have made in managing outages while improving customers service, or all of the above - a major shift towards a more positive view has taken place. Customers who have a positive view of their LDC and the industry exhibit less resistance to change.

You spring 2019 survey shows a drop from 13% [2017] to 5% [2019] of respondents who said paying their bill was ‘often a problem’. Also, the At Risk customer respondent levels dropped from 12% [2017] to 3% [2019], while the Ontario Benchmark change was 17% to 10%. To be clear, customers are still concerned about the costs of electricity as shown by low scores in the attribute “The cost of electricity is reasonable when compared to other utilities such as gas, cable or telephone [72%].”

Your survey was conducted, June 3 - June 12, 2019, and is based on 407 one-on-one telephone interviews with residential and small commercial customers who pay or look after the electricity bill. Survey findings for NPEI are enhanced with the inclusion of data from our UtilityPULSE database and the independently produced Ontario and National Benchmarks.

Helping the LDC generate higher levels of customer satisfaction, or maintaining their current high level, will be based on doing the core job as promised by being professional, efficient and cost-effective. But expectations continue to change. From examining the trends in data from the UtilityPULSE database, three key observations emerge. They are: customers want to know they have been heard, they have reasonable access to services, and, their LDC is pro-actively communicating – especially during emergency situations.

82%
Pro-actively communicates changes and issues

90%
Provides excellent quality services

92%
Standard of reliability meets expectations

91%
Delivers on its service commitments

Base: total respondents:
Top 2 Boxes: "Strongly agree + agree"

The Core Responsibilities

NPEI survey respondents agree their LDC: Provides consistent, reliable electricity 94%, Quickly handles outages and restores power 91%, Accurate billing 91% and Makes electricity safety a top priority for employees, contractors, and the public 89%.

Issues: Billing and Blackouts, the "Killer B's"

In a world, which is becoming more complex, and where people are time-pressed, outage and billing issues are likely to motivate customers to contact their LDC.

Problems: Blackouts

Percentage of Respondents indicating that they had a Blackout or Outage problem in the last 12 months			
	NPEI	**National**	**Ontario**
2019	32%	39%	44%

Base: total respondents

Problems: Billing issues

Percentage of Respondents indicating that they had a Billing problem in the last 12 months			
	NPEI	**National**	**Ontario**
2019	6%	9%	9%

Base: total respondents

While it is true, NPEI receives very good operational scores, it also has a responsibility to professionally and quickly deal with issues customers contact them about. In a complex electricity industry world, this puts additional strain on the skills and competencies of everyone who interacts with customers.

Customer Service

Satisfaction with Customer Service			
Top 2 Boxes: 'very + fairly satisfied'	**NPEI**	**National**	**Ontario**
The time it took to contact someone	88%	66%	64%
The time it took someone to deal with your problem	85%	72%	65%
The helpfulness of the staff who dealt with you	88%	70%	64%
The knowledge of the staff who dealt with you	85%	70%	64%
The level of courtesy of the staff who dealt with you	91%	78%	70%
The quality of information provided by the staff who dealt with you	82%	73%	61%

Base: total respondents who contacted the utility

Traditionally LDCs handle inbound, or customer initiated communications when there are issues. However, more and more customers have an expectation their LDC will also be proficient with outbound communications regarding the important issues.

Communication Score

The pressure to communicate via multiple communication platforms continues to increase. There is also an expectation the utility will, from an outbound perspective, contact the customer via their preferred channel.

Communication Score		
	Ontario LDCs	**NPEI**
Communication Score	79%	82%

Base: An aggregate of respondents from Fall 2018 participating LDCs / total respondents from the local utility

Communication channels preferred by customers to receive notice about Billing Issue

Most, if not all, of our LDC clients, expect that customers will utilize the electronic channels for getting information or dealing with issues. By doing so, costs for the LDC should decrease. However, in a world where customers expect some outbound contact, they expect their LDC to use those channels to communicate directly with them. Therefore, when problems do occur, and the LDC must initiate contact with their customer, it would be beneficial to the process if customers were contacted via channels they most prefer.

NPEI's customers' preferred or primary method for NPEI to contact them about billing issues are as follows:

Preferred method of communication to receive notice of a billing issue		
	Ontario LDCs	**NPEI**
Telephone	56%	63%
Voice Mail	2%	2%
Text	7%	4%
Email	34%	30%
Don't know	1%	0%

Base: An aggregate of respondents from Fall 2018 participating LDCs / total respondents from the local utility

Communication during Unplanned Outages

In times of emergency, be they extreme weather events or major equipment failures that cause blackouts and unplanned outages, customer communication can help customers understand what to expect next and when

disrupted electricity service might be restored. Early and effective communication helps increase confidence in and credibility of the electricity service provider.

Method of communication Customers prefer their LDC uses during an UNPLANNED OUTAGE							
Recorded Telephone Message	**Email Notice**	**Posted on the Website**	**Social Media**	**Local Radio**	**Local TV**	**Text Message**	**Alert on APP**
33%	20%	4%	7%	4%	4%	21%	3%

Base: total respondents

Communication about general news or changes in the industry

Method of communication Customers prefer their LDC uses about general news		
	Ontario LDCs	**NPEI**
Recorded telephone message	22%	24%
Email notice	40%	36%
Posted on the utility's website	7%	8%
Social media	6%	7%
Local radio	5%	5%
Local TV	5%	4%
Text message	9%	9%
Alert on APP	2%	1%

Base: An aggregate of respondents from Fall 2018 participating LDCs / total respondents from the local utility

Notice the difference in the preferred channel based on subject matter. NPEI shouldn't, for example, assume a customer who prefers email for a billing issue will want an email for outage issues. Getting the most out of your CRM system is becoming increasingly important.

Providing communication channels that are effective and meet customers' needs is key to improving the customer experience. To do this, NPEI must understand how customers communicate with you, and how they would like NPEI to communicate with them in the future. Knowing this will allow NPEI to: allocate resources where they are most needed; tailor services to meet customers' needs; and, identify where improvements can be made.

Customers were asked about their level of satisfaction with the information provided by NPEI on the following:

Satisfaction with information provided

Top 2 Boxes: 'very + fairly satisfied'	Ontario LDCs	NPEI
The amount of information available to you about energy conservation	82%	86%
The quality of information available when outages occur	73%	80%
The electricity safety education provided to the public	74%	79%
The timeliness and relevance of information for things such as planned outages, construction activity, tree trimming.	78%	80%

Base: An aggregate of respondents from Fall 2018 participating LDCs / total respondents from the local utility

Based on customer responses, NPEI has achieved a score of 82% for Communications while Ontario LDCs rated 79%.

The Convenience of Services Score

Rising customer expectations and demands means customers expect to be able to contact you 24 hours a day, seven days a week using various communication avenues, i.e. Telephone, your website and/or even social media. Customers expect flexible and more personalized services. Providing customers with clear, easy to access services and information which is easy to understand has a significant impact on the customer experience.

Access to services		
Top 2 Boxes: 'very + somewhat satisfied'	**Ontario LDCs**	**NPEI**
The availability of call-centre staff Monday to Friday from 8:30 am to 4:30 pm	76%	80%
The 24/7 availability of system operators to respond to outages	77%	84%
The online self-serve options for managing your account	63%	64%
The online self-serve options for request services	56%	62%
The ability to walk in for customer service Monday to Friday from 8:30 am to 4:00 pm	n/a	75%

Base: An aggregate of respondents from Fall 2018 participating LDCs / total respondents from the local utility

Based on customer responses, NPEI has rated 82% for Convenience of Services while Ontario LDCs rated 79%.

Credibility & Trust Index

As society becomes more complicated and complex, the opportunities for failure increase. A key to healthy relationships with customers is to be trusted, trustworthy and credible. NPEI Credibility & Trust score is 88% while the Ontario benchmark is 80% and the National benchmark is 81%. NPEI's Credibility & Trust score is impressive.

Customer Experience Performance rating (CEPr)

Do customers believe they will have a good experience if/when they do contact their LDC? Or do they believe they must prepare for 'war'? Of course, subject matter and customer affinity levels play a role in determining how a customer might prepare for interaction with a professional at NPEI.

Customer Experience Performance rating (CEPr)			
	NPEI	National	Ontario
CEPr: all respondents	88%	84%	83%

Base: total respondents

Ensuring that the customer experience is a good one, requires high quality services and well-trained people. Survey respondents gave NPEI excellent operational and representative scores.

Operational Attributes			
	NPEI	**National**	**Ontario**
Provides consistent, reliable energy	94%	89%	90%
Quickly handles outages and restores power	91%	87%	86%
Accurate billing	91%	86%	87%

Base: total respondents with an opinion

Representative Attributes			
	NPEI	**National**	**Ontario**
Deals professionally with customers' problems	89%	83%	82%
Is 'easy to do business with'	90%	82%	82%
Customer-focused and treats customers as if they're valued	87%	80%	79%

Base: total respondents with an opinion

Customer Centric Engagement Index

The term "customer engagement" is used by many but understood by few. The purpose of customer engagement is to have two-way interactions which build understanding between the stakeholders and stronger

professional business-like relationships. Customers who are highly engaged are more inclined to look past costs and money issues and be more supportive of what the LDC wants to do or accomplish.

As we have stated in previous reports: Customer Engagement is about how customers think, feel and act towards the organization. Ensuring customers respond positively requires they be rationally satisfied with the services provided AND emotionally connected to the LDC and its brand.

Utility Customer Centric Engagement Index (CCEI)

	NPEI	National	Ontario
CCEI	87%	81%	80%

Base: total respondents

Customer Satisfaction

By itself, this metric is not good enough to gain a picture of how well an LDC is doing but it is a measure about whether the LDC is "doing the job" as expected. However, without satisfaction, there is no gateway to loyalty.

SATISFACTION SCORES – Electricity customers' satisfaction

Top 2 Boxes: 'very + fairly satisfied'	NPEI	National	Ontario
PRE: Initial Satisfaction Scores	96%	91%	91%
POST: End of Interview	95%	91%	89%

Base: total respondents

The real prize is in the development of a relationship with customers. More good things exist when a customer has a high affinity for the LDC than when they dislike it. At Risk customers are more likely to complain than other customers when there are issues. Secure customers are more likely to support the direction of their LDC.

Loyalty Groups

Customer Loyalty Groups				
NPEI	**Secure**	**Favorable**	**Indifferent**	**At Risk**
2019	37%	22%	38%	3%

Base: total respondents

In the monopoly world of the LDC, loyalty is an attitudinal metric. In private industry, it is a behavioural metric.

Customer Commitment

Electricity customers' loyalty – … Is a company that you would like to continue to do business with			
	NPEI	**National**	**Ontario**
Top 2 Boxes: 'Definitely + Probably' would continue	91%	80%	78%

Base: total respondents

Customer Advocacy

Electricity customers' loyalty – … is a company that you would recommend to a friend or colleague			
	NPEI	**National**	**Ontario**
Top 2 boxes: 'Definitely + Probably' would recommend	87%	76%	70%

Base: total respondents

UtilityPULSE Report Card®

The purpose of the UtilityPULSE Report Card is to provide electric utilities with a snapshot of performance – on the things customers deem to be important.

NPEI's UtilityPULSE Report Card®

Performance

	CATEGORY	NPEI	National	Ontario
1	**Customer Care**	**A**	**B+**	**B+**
	Price and Value	A	B	B
	Customer Service	A	A	B+
2	**Company Image**	**A**	**B+**	**B+**
	Company Leadership	A	B+	B+
	Corporate Stewardship	A	A	B+
3	**Management Operations**	**A+**	**A**	**A**
	Operational Effectiveness	A+	A	A
	Power Quality and Reliability	A+	A	A
	OVERALL	**A**	**A**	**B+**

Base: total respondents

Looking to the future, where to from here?

Technological advances, social disruptions, and other issues will continue for everyone in the LDC industry. Fixing the ills of yesterday are not possible, but instilling confidence that the LDC can handle future customer needs & wants strengthens the customer-supplier relationship. By engaging stakeholders and obtaining their input in undertaking a priority planning process helps to build "prepared minds"—that is, to make sure that the LDC decision makers have a solid understanding of customer priorities, and what the business might need to change or make investments in.

High priority items based on information taken from our UtilityPULSE database include: ‘Pro-actively maintaining and upgrading equipment,’ ‘Reducing response times to outages,’ and ‘Investing more in the electricity grid to reduce outages and to increase reliability and safety.

The high scoring attributes demonstrate NPEI's operational effectiveness, while the low scoring attributes point to a need for more marketing communications and/or PR types of activities.

Highest scoring attributes compared to the Ontario Benchmark

High scoring attributes			
Top 2 Boxes: ‘Strongly + Somewhat agree’	**NPEI**	**National**	**Ontario**
Provides consistent, reliable electricity	94%	89%	90%
Makes electricity safety a top priority for employees and contractors	89%	87%	86%
Quickly handles outages and restores power	91%	87%	86%
Has a standard of reliability that meets expectations	92%	88%	88%

Base: total respondents with an opinion

Lowest scoring attributes compared to the Ontario Benchmark

Low scoring attributes			
Top 2 Boxes: 'Strongly + Somewhat agree'	**NPEI**	**National**	**Ontario**
Spends money prudently	86%	73%	66%
Operates a cost-effective electricity system	82%	70%	71%
Provides good value for your money	81%	72%	71%
Cost of electricity is reasonable when compared to other utilities	72%	66%	61%

Base: total respondents with an opinion

Paying for electricity

Over the past eighteen months, data shows dramatic changes in customers' ability to pay. Whether the change is due to price reductions, or anticipated price reductions, or a better economy, is unclear. Ability to pay is highly correlated to satisfaction. The number one billing problem, for 21 years, is "the amount is too high."

Is paying for electricity a worry or a major problem?				
	Not a worry	**Sometimes**	**Often**	**Depends**
NPEI	74%	20%	5%	0%
National	71%	18%	7%	0%
Ontario	68%	21%	8%	1%

Base: total respondents

Numbers at a Glance

	NPEI	National	Ontario
Customer Satisfaction: Initial	96%	91%	91%
Customer Satisfaction: Post	95%	91%	89%
Communication Score	82%	--	79%
Overall Satisfaction with the most recent experience	84%	78%	77%
Convenience of Services Score	82%	--	79%
Customer Experience Performance Rating (CEPr)	88%	84%	83%
Customer Centric Engagement Index (CCEI)	87%	81%	80%
Credibility & Trust Index	88%	82%	81%
UtilityPulse Report Card©	A	A	B+

Over the past 5-6 years, LDCs have witnessed their customers move from being concerned about costs, to worried about cost, to being upset about costs and being angry about costs – and now returning to what we believe is a concern about costs. From a human nature point-of-view, when people are angry, they tend to look back in time to find someone or something to blame for their predicament. Now that customers have returned to being concerned, they are more apt to be looking forward while putting more focus on identifying and determining how they might handle future issues. UtilityPULSE data from 9,000+ customer interviews shows there is support for making pro-active investments in reliability, outage restoration, outage management, and communications.

We believe, for many in society, from 2008 to mid-2017 survival was the key goal less so in 2018 & 2019. The outlook for the economy is better; wages are improving and, job openings are more plentiful – therefore putting more focus on the future.

The good news is NPEI remains what we call an influential brand company. The safe, reliable distribution of electricity to homes and businesses is a job which makes life better, more interesting and meaningful for consumers and customers. As a company which affects the daily life of people and businesses – an influential brand – it must consistently demonstrate that it is credible, trusted, future-oriented, cares about customers, cares about safety, cares about the environment, is professional, has high standards and is a valued corporate citizen. NPEI has an impressive Credibility & Trust score of 88% compared to the Ontario Benchmark of 81%.

The industry is far more complex today than it was 21 years ago when we conducted the 1st Annual Customer Satisfaction survey for electric utilities. Data shows that being customer-centric is important for ensuring future success of the LDC. Customers want respect.

We recommend leveraging the results from your 2019 customer satisfaction survey by having meaningful conversations with everyone about your customers' – satisfaction, concerns, wants, etc. LDCs with a constructive employee culture with high levels of employee engagement and empowerment will have an easier time defining a future path forward.

Sid Ridgley
Simul/UtilityPULSE
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June 2019

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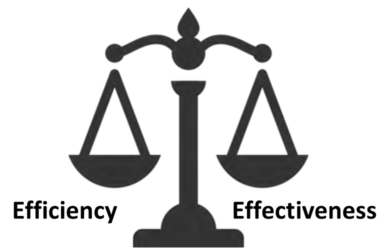
Satisfaction (pre & post)

As stated multiple times over many years, measuring satisfaction is an important starting point, for the creation of loyal customers. However, it is a misnomer to conclude that highly satisfied customers are also customers with a high affinity or loyalty quotient. One can be satisfied but not necessarily loyal. But it is true to conclude that the LDC (its people) must do the job as expected and required before there can be a positive emotional connection.

We've stated in the past, a focus on satisfaction prompts an organization to continue to evolve in ways which make sense to those who pay the bills. A focus on satisfaction is a focus on effectiveness in the delivery of service to the customer. Satisfied customers who trust their LDC may be more likely to seek advice, i.e. energy efficiency methods and may be more receptive to important messages, i.e. safety, new capital projects, etc.

About ratings/measures:



- Satisfaction is not a program; it is an outcome.
- ***Efficiency*** *is about achieving objectives with the minimum amount of people, time, money and other resources.*
- ***Effectiveness*** *ratings are measures keeping the organization and its people more future focused than efficiency ratings*

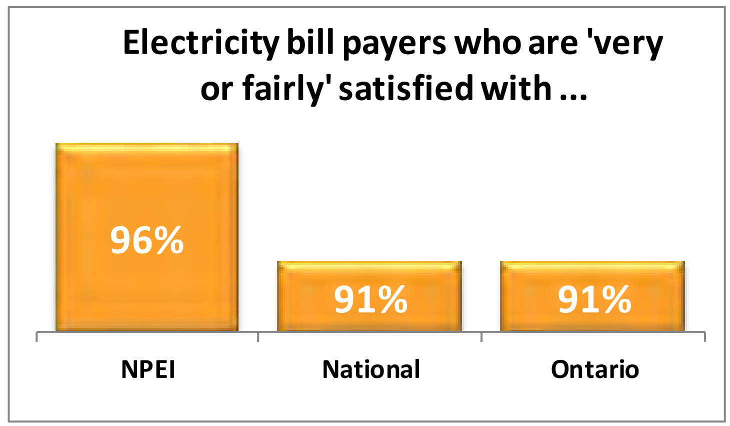
Finding the right balance between efficiency and effectiveness measures is difficult.

Efficiency ratings won't lead to satisfaction, but they can lead to dissatisfaction. Taking 90 seconds to answer the phone will create an agitated customer who, for the most part starts off being dissatisfied with the service – before you've even had a chance to deal with or solve their problem. Answering the phone in 20 seconds but not solving the customer's problem is not going to ameliorate the customer's perception about the transaction.

Customer expectations of their electricity LDC have evolved past the "provide electricity reliably, safely and billed both accurately with fair pricing". They do expect their LDC to be ethical, forward-thinking, competent and trustworthy.

- **Satisfaction** happens when utility core services meet or exceed customer's needs, wants, or expectations.

- **Loyalty** occurs when a customer makes an emotional connection with their electric utility on a diverse range of expectations beyond core services.



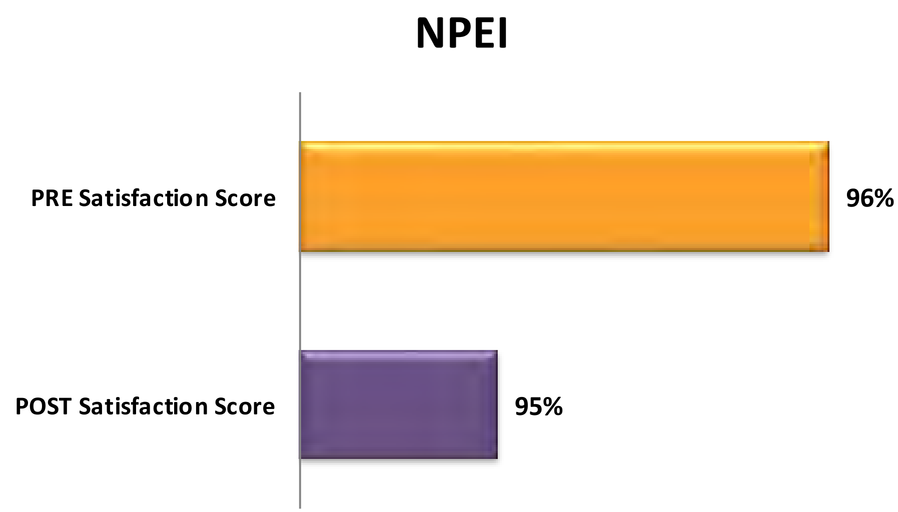
Base: total respondents

Satisfaction alone does not make a customer loyal; a willingness to commit and advocate for a company along with satisfaction identifies the three basic customer attitudes which underpin loyalty profiles. While satisfaction is an important component of loyalty, the loyalty definition needs to incorporate more attitudinal and emotive components.

Electricity bill payers who are 'very or fairly' satisfied with…			
	2019	**2017**	**2014**
NPEI	96%	87%	84%
National	91%	90%	89%
Ontario	91%	85%	83%

Base: total respondents

In the Simul/UtilityPULSE Customer Satisfaction survey, the overall satisfaction question is asked both at the beginning (PRE) and the end (POST). Asking the general satisfaction question at the start of the survey avoids bias, and we obtain a spontaneous rating. This allows measurement of customers' overall impressions of the utility before prompting them to think of specific aspects of the relationship. After we have asked about specific aspects of the customer experience, we gain a more *considered* (or conditioned) response.



Base: total respondents

As with any enterprise, NPEI has an obligation to satisfy its customers. But the rewards for satisfying customers go far beyond "obligation". Customers with high levels of satisfaction handle problems far better than customers with low satisfaction. Stronger relationships with customers generate higher levels of involvement and participation. For employees, serving customers who are very satisfied are more enjoyable interactions than with customers who are very dissatisfied. Satisfied and engaged employees who work in an organizational culture which promotes service excellence with empowerment is an important key for completing the job both efficiently and effectively.

SATISFACTION SCORES – Electricity customers' satisfaction			
Top 2 Boxes: 'very + fairly satisfied'	**NPEI**	**National**	**Ontario**
PRE: Initial Satisfaction Scores	96%	91%	91%
POST: End of Interview	95%	91%	89%

Base: total respondents

A mutual correlation exists between employee and customer attitudes and loyalty. Employees who are trained well, have the right tools and are focused on successful outcomes for customers contribute greatly to the customers' perception of their utility. There is a direct, irrefutable link between empowered and engaged employees and customer satisfaction – after all -- *your employees are part of your brand and they deliver the promises you make.*

NPEI

SATISFACTION SCORES – Electricity customers' satisfaction		
Top 2 Boxes: 'very + fairly satisfied'	**Residential**	**Commercial**
Satisfaction Scores	95%	97%

Base: total respondents

SATISFACTION SCORES – Electricity customers' satisfaction [kwh usage]			
Top 2 Boxes: 'very + fairly satisfied'	**kWh Group 1**	**kWh Group 2**	**kWh Group 3**
Satisfaction Scores	93%	99%	92%

Base: total respondents

SATISFACTION SCORES – Electricity customers' satisfaction [Income]			
Top 2 Boxes: 'very + fairly satisfied'	**<$30K**	**$30 – 75K**	**$75K +**
Satisfaction Scores	96%	95%	97%

Base: total respondents

Customer Service

As written in previous years, given the rapidly expanding availability and use of technology finding an appropriate balance between automated self-service and human-interactive service is a huge challenge for all involved in providing service to customers. Customer Service is about the experience your customers have with your utility, your products, and your service – regardless of the channel for used for delivering customer service. The goal is to ensure each of your customers receives high-quality customer service and an experience which meets or exceeds their expectations - on each and every interaction with the LDC.

Given the increased complexity for delivery customer service, we have seen a shift towards a stronger focus on the touch points which create the customer experience.

Most of us want the same things when we are customers: We want to be treated with respect. We want to be listened to. We don't want to be bounced around or ignored or treated as inferior. The customer experience is largely defined by the outcomes generated when customers have a need, want to solve a problem, or simply want answers to issues/concerns they face.

With more technology there will be more shifting of calls away from the call centre. However, the volume of calls which remain are and will be more complex and challenging. We're already witnessing the fact that calls are taking longer to deal with customer issues.

Customers are more concerned about outcomes, and they want their issue, problem or concern to be dealt with in a professional, knowledgeable, and timely manner. Respondents were asked about six aspects of their most recent experience with a representative from NPEI.

- Information – the quality of information provided
- Staff attitude – the level of courtesy
- Professionalism – the knowledge of staff
- Delivery – helpfulness of staff
- Timeliness – the length of time it took to get what they needed
- Accessibility – how easy it was to contact someone

Base: total respondents who contacted the utility

Satisfaction with Customer Service			
Top 2 Boxes: 'very + fairly satisfied'	**NPEI**	**National**	**Ontario**
The time it took to contact someone	88%	66%	64%
The time it took someone to deal with your problem	85%	72%	65%
The helpfulness of the staff who dealt with you	88%	70%	64%
The knowledge of the staff who dealt with you	85%	70%	64%
The level of courtesy of the staff who dealt with you	91%	78%	70%
The quality of information provided by the staff who dealt with you	82%	73%	61%

Base: total respondents who contacted the utility

Overall satisfaction with most recent experience			
	NPEI	**National**	**Ontario**
Top 2 Boxes: 'very + fairly satisfied'	84%	78%	77%

Base: total respondents who contacted the utility

Every interaction with a customer is an opportunity to generate higher levels of affinity. It is fool-hardy to view the ratings shown above as ratings for the "call-centre" because every person in NPEI interacts with a customer or supports those who do have person-to-person contact with a customer. Empowerment is the backbone of the service recovery principle. In the face of error or problems, acting quickly and decisively, being empowered and turning a dissatisfied customer into a satisfied one tends to have a positive impact.

Customer Focus – Service Quality

Current measures in the LDC scorecard are: New Residential Services Connected on Time; Scheduled Appointments Met on Time; and, Telephone Calls Answered on Time. These are good examples of efficiency measures as all are time-based. Showing up on time may not create satisfaction; not showing up on time will cause dissatisfaction.

UtilityPULSE findings from working with many LDCs over the past few years indicate it is much harder to get great ratings from customers who may not know much about their LDC's standards for service. Despite this, service quality ratings for NPEI are very good and above the Ontario benchmark.

Other dimensions of Service Quality which customers value include:

Customer Service Quality

Top 2 boxes, 'strongly + somewhat agree'	NPEI	National	Ontario
Deals professionally with customers' problems	89%	83%	82%
Customer-focused and treats customers as if they're valued	87%	80%	79%
Is a company that is 'easy to do business with'	90%	82%	82%

Base: total respondents with an opinion

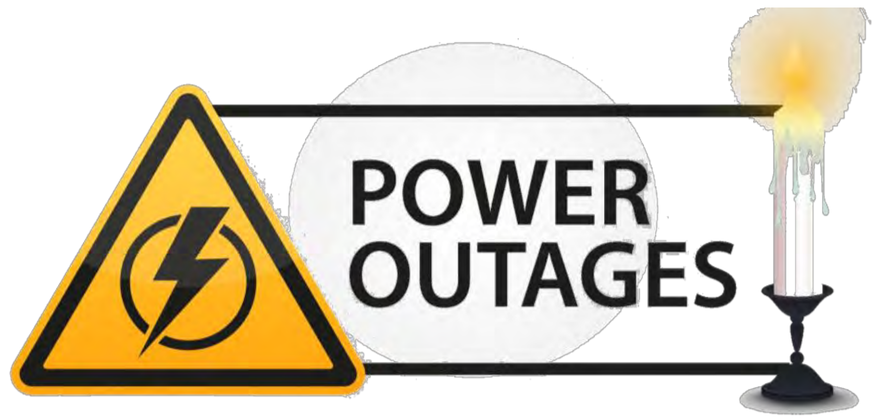
We live in an imperfect world, so mistakes are bound to happen. In the LDC world, not all customer problems are mistakes, some are externally driven. None-the-less customers expect professionalism when interacting with "their" LDC.

Bill Payers' Problems and Problem Resolution

As previously written over multiple years, we call blackouts (outages) and billing problems, the "Killer B's", the two issues which are most likely to cause grief to utility customers.

At one time, if the power went off for a few minutes, it was considered annoying and inconvenient. However, with the onset of computers and smart appliances in homes and businesses, a power outage is now unbearable. Customers have little tolerance for an interruption in their flow of electricity.

LDCs have certainly been putting more energy into disseminating information to customers about outages. Many have installed an "outage map" on their website. However, our UP database shows only 13% of customers who accessed their LDC's website did so to get information about an outage or look at the outage map!



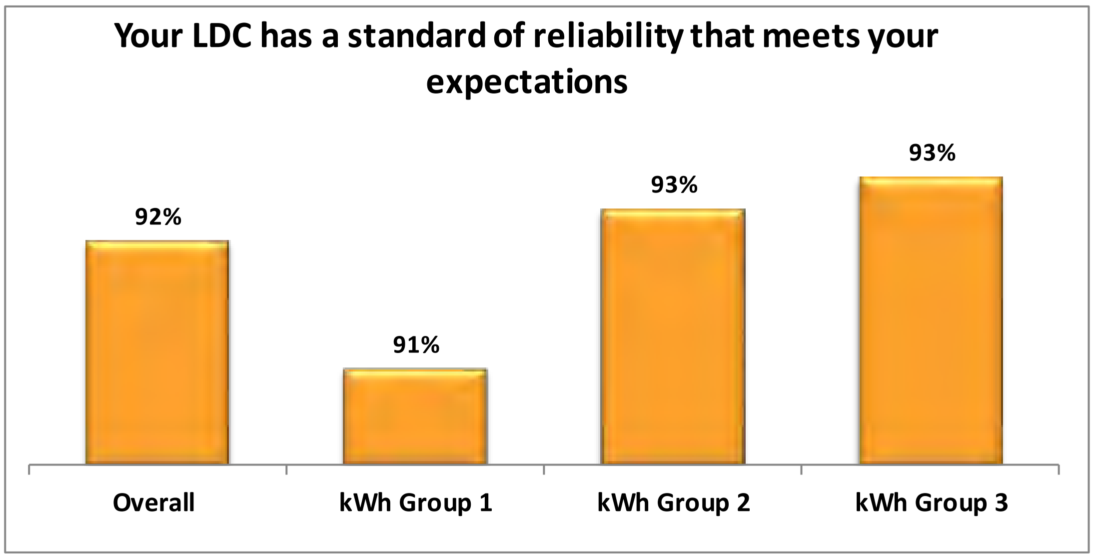
32% of NPEI respondents claimed they experienced an outage problem in the past 12 months.

Like it or not, there will be times when the power goes off – and for reasons beyond the control of the LDC.

Percentage of Respondents indicating that they had a Blackout or Outage problem in the last 12 months			
	NPEI	National	Ontario
2019	32%	39%	44%
2017	29%	37%	38%
2014	51%	47%	49%

Base: total respondents

92% of NPEI respondents agree ('strongly + somewhat') the utility's standard of reliability is consistent with their expectations.



Base: total respondents

For nearly every business, the simple act of collecting payments from customers is quite complex. Organizations want to make it easy and convenient for customers to pay, so they offer multiple choices of payment types and channels. However, making it easy for the customer often makes it more complex—and costly—for the business and is certainly not without its problems or flaws.

Percentage of Respondents indicating that they had a Billing problem in the last 12 months			
	NPEI	**National**	**Ontario**
2019	6%	9%	9%
2017	20%	12%	15%
2014	18%	16%	25%

Base: total respondents

The impact of poor billing on a utility's business is considerable, in terms of costs incurred handling customer queries and complaints. The quality of billing remains a driving force behind managing customer satisfaction and can help utilities reduce costs associated with customer service. Through reducing the total number of calls to a utility by providing accurate bills which are easily understood, a utility stems the flow of billing-related complaints into its call-centre. However, customers have a different definition than their utility as to what constitutes a billing problem.

Types of Billing Problems

	NPEI 2019	NPEI 2017	NPEI 2014
The amount owed was too high	48%	78%	72%
Complaint about rates or charges	12%	5%	26%
Wrong information on the bill	12%	2%	--
Did not receive the bill	8%	--	--
Payment incorrectly recorded	4%	1%	--
Change name/address	4%	--	1%
Too many extra charges	4%	4%	--
Missed payment	4%	--	--

Base: total respondents with billing problems

Initial Satisfaction level:
2019: 96%
2017: 87%
2014: 84%

The perception of the factors causing high-bills impacts satisfaction levels.

28% of NPEI respondents with an outage problem did contact the utility;

48% of NPEI respondents with a billing problem did contact the utility.

First Contact Resolution (FCR) rates are an important metric for improving call center performance. The first step in improving “FCR” is to survey your front-line customer touch-points and understand what kind of assistance and information customers are seeking in these situations. Once you clearly understand what kinds of interactions are taking place at each of your initial customer touch-points, you can then take steps to improve those interactions.

Percentage of Respondents who contacted their utility and had their problem solved in the last 12 months	
	NPEI
Yes	77%
No	18%

Base: total respondents with a problem who contacted their utility

Interestingly when customers do have a problem and contact their LDC, and get the problem solved their satisfaction ratings are very similar to the overall level of satisfaction that exists if not slightly higher, however, failing to deal or resolve a customer's problem causes satisfaction levels to drop.

SATISFACTION SCORES – Electricity customers' satisfaction			
NPEI	**Overall**	**Problems Solved**	**Problems Not Solved**
Top 2 Boxes: 'very + fairly satisfied'	96%	96%	77%

Base: total respondents with a problem who contacted their utility

We believe a major challenge for most LDCs is about increasing their knowledge about their customers and how they prefer communications to take place. Most CRM systems seem to be inadequate for providing this information about preferences.

Communication when there is an Issue

Utilities need to know the response they are seeking from customers when planning their communications and outreach. Sending inserts with monthly bills which provide information to a customer is passive and not very effective. Although your customer audience is captive, a poorly targeted message is often ignored. Posting information on a website—unless a customer is actively searching for it—will likely not be found. Email blasts and social media campaigns will reach customers but may not necessarily lead to action. Such messages are typically read when in transit or multitasking, making them an afterthought. So, it often takes several pushes for these messages to resonate before action is taken. Successful marketing and messaging is about keeping communications simple, consistent, and continually reinforced.

Communication channels preferred by customers to receive notice about Billing Issue

Billing issues have long been a major cause of customer inquiry and complaint. Not only are bills a key part of an LDC's revenue management processes, but they're also an essential element and touchpoint in their relationship with their customers. For many customers, it is one of the very few touchpoints they have with their LDC. Because of its nature, the bill is usually viewed by customers as a wholly negative communication. Therefore, when problems do occur, and the LDC must initiate contact with their customer, it would be beneficial to the process if customers were contacted via channels they most prefer.

NPEI's customers' preferred or primary method for NPEI to contact them about billing issues are as follows:

Preferred method of communication to receive notice of a billing issue		
	Ontario LDCs	**NPEI**
Telephone	56%	63%
Voice Mail	2%	2%
Text	7%	4%
Email	34%	30%
Don't know	1%	0%

Base: An aggregate of respondents from Fall 2018 participating LDCs / total respondents from the local utility

Effective communication is essential to provide good customer service, improve efficiency and reduce costs. LDCs must maximize the effectiveness of their communications and improve customer interactions consistently across some media channels and customer touch points.

Communication during Unplanned Outages

In times of emergency, be they extreme weather events or major equipment failures that cause blackouts and unplanned outages, customer communication can help customers understand what to expect next and when disrupted electricity service might be restored. Early and effective communication helps increase confidence in and credibility of the electricity service provider.

Respondents were asked which communication channel they most preferred NPEI to use during an unplanned outage.

Method of communication Customers prefer their LDC uses during an UNPLANNED OUTAGE							
Recorded Telephone Message	**Email Notice**	**Posted on the Website**	**Social Media**	**Local Radio**	**Local TV**	**Text Message**	**Alert on APP**
33%	20%	4%	7%	4%	4%	21%	3%

Base: total respondents

Communication about general news or changes in the industry

While there are many ways to communicate, information and messaging is most effective when delivered through channels preferred by customers. Whether it's text, email, or phone call, it's crucial to recognize that to make communications more effective, the LDC's messaging should be simple, clear, fact-based, and consistent.

Respondents were asked which communication channel they most preferred NPEI to use to communicate general news or changes in the industry.

Method of communication Customers prefer their LDC uses about general news		
	Ontario LDCs	**NPEI**
Recorded telephone message	22%	24%
Email notice	40%	36%
Posted on the utility's website	7%	8%
Social media	6%	7%
Local radio	5%	5%
Local TV	5%	4%
Text message	9%	9%
Alert on APP	2%	1%

Base: An aggregate of respondents from Fall 2018 participating LDCs / total respondents from the local utility

Providing communication channels that are effective and meet customers' needs is key to improving the customer experience. To do this, NPEI must understand how customers communicate with you, and how they would like NPEI to communicate with them in the future. Knowing this will allow NPEI to: allocate resources where they are most needed; tailor services to meet customers' needs; and, identify where improvements can be made.

However, while most customers appear to have capacity and willingness to use digital channels, there are also customers who do not access digital platforms for a variety of reasons, such as a lack of ability or resources, or due to a preference for other channels. NPEI will need to consider how these customers can be supported and encouraged to use digital services in the future.

Communication and Services Measurement

Electric utilities across Canada are increasingly seeing the need to invest in aging infrastructure, new technologies, regulatory requirements, and a skilled workforce. They are addressing these needs to uphold their public service duty, all the while keeping in mind the need to communicate with their customers. Part of communication is the requirement of providing information and/or education to the public to raise the level of understanding surrounding an issue or topic that may be of practical concern to residents.

Consumer information is meant to attune consumers to certain problems [i.e., outage problems, etc.], create awareness and educate [i.e. electricity safety, etc.] or even guide (influence) their behaviour [i.e., energy conservation, etc.].

Customers, who are also consumers, have additional needs for information and education. Survey respondents, who are bill payers, were asked about their level of satisfaction with the information provided by NPEI on the following:

Satisfaction with information provided		
Top 2 Boxes: 'very + fairly satisfied'	**Ontario LDCs**	**NPEI**
The amount of information available to you about energy conservation	82%	86%
The quality of information available when outages occur	73%	80%
The electricity safety education provided to the public	74%	79%
The timeliness and relevance of information for things such as planned outages, construction activity, tree trimming.	78%	80%

Base: An aggregate of respondents from Fall 2018 participating LDCs / total respondents from the local utility

Communication Score		
	Ontario LDCs	**NPEI**
Communication Score	79%	82%

Base: An aggregate of respondents from Fall 2018 participating LDCs / total respondents from the local utility

Based on customer responses, NPEI has achieved a score of 82% for communications.

Convenience of Services Score

Rising customer expectations and demands means customers expect to be able to contact you 24 hours a day, seven days a week using various communication avenues, i.e. telephone, your website and/or even social media. Customers expect flexible and more personalized services. Regardless of the day of the week or time of day, when a customer has a problem they want to deal with it and have it resolved – when it is convenient for them.

Access to services		
Top 2 Boxes: 'very + somewhat satisfied'	**Ontario LDCs**	**NPEI**
The availability of call-centre staff Monday to Friday from 8:30 am to 4:30 pm	76%	80%
The 24/7 availability of system operators to respond to outages	77%	84%
The online self-serve options for managing your account	63%	64%
The online self-serve options for request services	56%	62%
The ability to walk in for customer service Monday to Friday from 8:30 am to 4:00 pm	n/a	75%

Base: An aggregate of respondents from Fall 2018 participating LDCs / total respondents from the local utility

When customers have a high level of satisfaction with access to services, it is much easier for LDCs to forge a new kind of relationship with its customers which, in turn, helps all parties successfully deal with the issues and opportunities of the new energy world.

Digital exclusion – some people may not have access to the internet at home, and that may mean they would not have access to information and services online. Data from the UtilityPULSE database shows about 17% of survey respondents in 2017 and 14% of survey respondents in 2018 do not have access to the internet. Survey respondents who earn less than $30,000 per year indicated that 44% in 2017 and 37% in 2018 didn't have access to the internet. It is true these access numbers vary based on the affluence of the community.

Also, there is an age bias towards the use of technology.

NPEI needs to continue to recognize this and ensure that customers may access services via alternate formats where necessary and feasible.

Convenience of Services Score

	Ontario LDCs	NPEI
Convenience of Services Score	79%	82%

Base: An aggregate of respondents from Fall 2018 participating LDCs / total respondents from the local utility

Providing customers with clear, easy to access services and information which is easy to understand has a significant impact on the customer experience.

Based on customer responses, NPEI has rated 82% for Convenience of Services.

Customer Experience Performance rating (CEPr)

The CEPr score is an effectiveness rating and is affected by many dimensions of service. Every touch point with customers on the phone, website or in-person influences what customers think and feel about the organization. While an excellent transaction today creates a positive experience today, the perception created is future transactions will be excellent too. Of course, a negative transaction creates the perception future transactions will be negative.

When the customer experience is strong, the opportunity to build loyalty is great. When the experience is a negative one, customers often conclude the organization doesn't care. When a customer believes the organization doesn't care, outrage and anger are a very real possibility.

Understanding your customer's expectations for service is the first step in providing an amazing customer experience. It is essential customer care call centers develop a comprehensive understanding of what

At the heart of the CEPr are 4 central questions:

1. *Are interactions with the organization professional and productive?*
2. *Is the organization 'easy to deal with'?*
3. *Does the organization effectively meet your needs?*
4. *Does the organization provide high quality services?*

customers expect from them, whether their needs are being met and how they can improve their service to meet their expectations.

Some of the factors which contribute to the overall customer experience:

- Delivering accessible and consistent customer service (multi-channel)
- Understanding customer expectations
- Maintaining timely resolution timelines
- Providing effective communication(s) according to customer needs
- Demonstrating responsiveness
- Speeding up problem resolution
- Conducting problem analysis to prevent recurring issues
- Easy to do business with
- Seeking customer feedback and following through on recommendations

Customer Experience Performance rating (CEPr)			
	NPEI	**National**	**Ontario**
CEPr: all respondents	88%	84%	83%

Base: total respondents

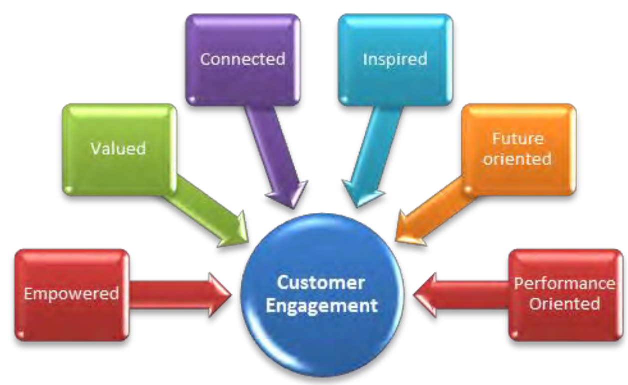
The CEPr for NPEI is 88%. This rating would suggest that a very large majority of customers have a belief they will have a good to excellent experience dealing with NPEI professionals.

Customer Centric Engagement Index (CCEI)

Customer engagement and customer satisfaction are very different measures. We believe generating high scores in customer engagement is more difficult than customer satisfaction. For example, a customer can be highly satisfied when the LDC reliability delivers electricity, bills the customer properly and quickly deals with outages. Essentially when the LDC does what it promises to do, then satisfaction follows.

Customer engagement is about connecting with customers in ways to demonstrate the LDC has heard the customer, understands the customer's needs, wants, desires and issues. When the LDC does demonstrate hearing and understanding, the result is higher levels of emotional connection, i.e., feelings that the people at the LDC care, respect and value their customers or are prepared to go-out-of-their-way (if necessary) to help.

Customer engagement is often thought of as a series of activities involving the customer such as conducting a survey, holding town hall type meetings, focus groups, etc. One could call these types of activities as the behaviour side of engagement. However, there is an emotional side to engagement.



UtilityPULSE has identified the six key dimensions of what defines customer engagement. They are: empowered, valued, connected, inspired, future-oriented and performance oriented. Customer-centric engagement is a measure of "goodwill" towards the utility. The UP database does show Secure customers believe they are more highly engaged with their LDC than customers who are At Risk.

This survey also provides you with an emotional look at engagement. The UtilityPULSE CCEI is a gauge of the amount of goodwill which has been generated. High numbers in CCEI suggest there is a high level of goodwill amongst your customers – this is important for two reasons. First, when something goes awry for the utility, goodwill helps the utility to be resilient. Second, goodwill encourages active participation in requests to participate in engagement activities or program offerings from the utility.

The CCEI is a metric designed to get a more in-depth look at the attachment a customer has with your LDC and its brand. High levels of customer engagement (emotional) correlate strongly to high levels of Secure and Favourable customer numbers.

Engagement is how customers think, feel and act towards the organization. As such, ensuring customers respond in a positive way requires they are rationally satisfied with the services provided AND emotionally connected to your LDC and its brand. The more frequently and consistently an organization's products and services can connect with a customer, especially on an emotional level, the stronger and deeper the customer becomes engaged with the organization.

Utility Customer Centric Engagement Index (CCEI)			
	NPEI	**National**	**Ontario**
CCEI	87%	81%	80%

Base: total respondents

Customers who are less engaged, as measured by the CCEI are more likely to let costs and/or price impact their perceptions of their LDC. Customers who are highly engaged are more inclined to look past costs and money issues and use a rational approach to make values-based decisions. Highly engaged customers have a stronger emotional connection to your utility. It's this emotional connection which will drive commitment, loyalty, and advocacy.

Using the measures of Satisfaction and Engagement the LDCs relationship with its customers would fall into one of four quadrants: Q1- low satisfaction/low engagement; Q2- high satisfaction/low engagement; Q3- low satisfaction/high engagement and Q4- high satisfaction/high engagement. Most LDCs would agree to have customers fall into the Q1 quadrant isn't good and having customers fall into Q4 is ideal.

When LDCs have candid conversations with customers and employees about their joint and different needs & perspectives the better, the LDC can be for creating an excellent place to do business with and to work.

UtilityPULSE Report Card®

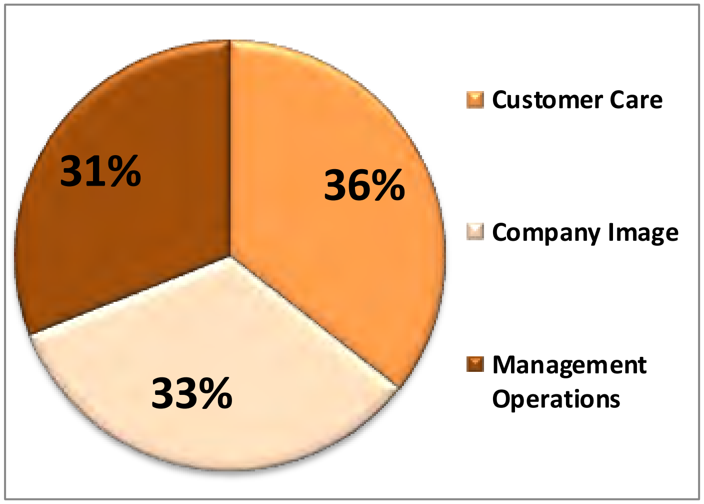
Simul's UtilityPULSE Report Card® is based on tens of thousands of customer interviews gathered over eighteen years. The purpose of the UtilityPULSE Report Card® is to provide electric utilities with a snapshot of performance – on the things customers deem to be important. Research has identified over 20 attributes, sorted into six topic categories (we call these drivers), which customers have used to describe their utility when they have been satisfied or very satisfied with their utility. These attributes form the nucleus, or base, from which "scores" are assigned. Customer satisfaction and loyalty also play a major role in the calculations.

There are two main dimensions of the UtilityPULSE Report Card® the first is customer psyche and the other is customer perceptions about how the utility executes its business.

The Psyche of Customers

Every utility has virtually the same responsibility – provide safe and reliable electricity – yet not all customers are the same. The following chart shows the weight or significance of each category to the customer when forming their overall impression of the utility. Three major themes, each with two major categories make up the UtilityPULSE Report Card®. In effect, the Report Card provides feedback about your customers' perception of the importance of each category and driver – as it relates to the benchmark.

UtilityPULSE Report Card® for NPEI



Base: total respondents

The UtilityPULSE Report Card® also provides customer perceptions about how your utility executes or performs its responsibilities. This is different, very different, from what a customer might say about a major concern or worry they have about electricity. As our survey has shown since its inception, the primary suggestion for improvement is "reduce prices", which is also a major concern which your customers have about municipal taxes, gas for the vehicle, and other utilities.

Readers of this report should note that the categories and drivers are interdependent. Which means, for example, failure to provide high levels of power quality and reliability will have a negative impact on customer perceptions as it relates to customer service. Customer care, when it doesn't meet customer expectations has a negative impact on Company Image, etc.

Defining the categories and major drivers:

Category: Customer Care

Drivers: Price and Value; Customer Service

Just because everyone likes good customer care, that in and by itself, is not a reason to provide it – though it may be important to do so. In highly competitive industries good customer service may be a differentiating factor. The case for electric utilities is simple, high levels of customer care result in less work (hence cost) of responding to customer inquiries and higher levels of acceptance of the utility's actions.

Price and Value:

Customers have to purchase electricity because life and lifestyle depend on it. This driver measures customer perceptions as to whether the total costs of electricity represent good value and whether the utility is seen as working in the best interests of its customers as it relates to keeping costs affordable.

Customer Service:

Customers do have needs, and every now and again have to interface with their utility. How the utility handles various customers' requests, and concerns are what this driver is all about. Promptly answering inquiries, providing sound information, keeping customers informed and doing so in a professional manner are the major components of this driver.

Category: Company Image

Drivers: Company Leadership; Corporate Stewardship

Utilities have an image even if they do not undertake any activities to try to build it. A company's image is both a simple and complex concept. It is simple because companies do create images which are easily described and recognized by their target customers. It is complex because it takes many discrete elements to create an image which includes, but is not limited to: advertising, marketing communications, publicity, service offering, and pricing.

An electric utility trying to manage its image has one more challenge to deal with, and that is the electric industry itself. There are so many players, residential customers (in particular) don't know who does what or who is responsible for what. So, when there are political or regulatory announcements, the local utility is often swept up into the collective reaction of the population.

Company Leadership

This driver is comprised of customer perceptions as it relates to industry leadership, keeping promises and being a respected company in the community.

Corporate Stewardship

Customers rely on electricity and want to know their utility is both a trusted and credible organization which is well managed, accountable, socially responsible and has its financial house in order.

Category: Management Operations

Drivers: Operational Effectiveness; Power Quality and Reliability

Electrical power is the primary product which utilities provide their customers and, they have very high expectations the power will be there when they need it. Customers have little tolerance for outages. The reality is, every utility must get this part right…no excuses. It is the utility's core business. This category and its drivers are clearly the most important for fulfilling the rational needs of a utility's customers.

Operational Effectiveness

This driver measures customers' perceptions as they relate to ensuring their utility runs smoothly. Attributes such as accurate billing and meter reading, completing service work in a professional and timely manner and maintaining equipment in good repair are deemed as important to customers.

Power Quality and Reliability

Power outages are a fact of life – and, customers know it. They expect their utility to provide consistent, reliable electricity, handle outages and restore power quickly and make using electricity safely an important priority.

NPEI's UtilityPULSE Report Card®

Performance

	CATEGORY	NPEI	National	Ontario
1	**Customer Care**	**A**	**B+**	**B+**
	Price and Value	A	B	B
	Customer Service	A	A	B+
2	**Company Image**	**A**	**B+**	**B+**
	Company Leadership	A	B+	B+
	Corporate Stewardship	A	A	B+
3	**Management Operations**	**A+**	**A**	**A**
	Operational Effectiveness	A+	A	A
	Power Quality and Reliability	A+	A	A
	OVERALL	**A**	**A**	**B+**

Base: total respondents

Ontario LDCs get a “C” rating for ‘cost of electricity is reasonable when compared to other utilities such as gas, cable, and telephone’ C+ rating for ‘spends money prudently’.

As the UtilityPULSE Report Card® shows, the total customer experience with an electric utility is defined as more than "keeping the lights on". Customers deal with your utility every day for a variety of reasons, most likely because they need someone to help them solve a problem, answer a question or take their order for service. All your employees, from customer service representatives to linemen, leave a lasting impression on the customers they interact with. In effect, there are many moments of truth. Moments of truth are every customer touch point a utility has with their customers. Therefore, managing these moments of truth creates higher levels of Secure customers while reducing the number of At Risk customers which exist.

It's the small things done consistently that matter: Things like greeting every customer, whether on the phone or in person, in a friendly and helpful manner. Things like listening to the customer's needs, providing solutions to their problems and showing appreciation to the customer for their business.

Utilities now recognize customer communications as a valuable aspect of their business. The better a utility communicates with customers in a manner which speaks to them; the more satisfied they are with their overall service. "Sending out information" is not the same as having a "conversation" with a customer. We believe it is increasingly important to channel your communications to the various customer segments which exist.

Obviously, employees – in every area – play a critical role in customer service success. Consequently, how they feel about their job responsibilities and role in the company will be communicated indirectly through the level of service which they provide customers with whom they interact. The reality is engaged employees are the key to excellent customer care.

Our survey work with employees shows there are many elements of an organizational culture to support the people model needed to achieve high levels of engagement.

Our research has identified 6 main drivers which promote and support people giving their best:

People Model

- **Empowered**
- **Valued**
- **Connected**
- **Inspired**
- **Growing**
- **Performance oriented**

There are 12 key processes from “attracting employees” to “saying goodbye to employees” are part of your people model to get the best performance from every employee.

We believe taking the time to understand the difference between employee satisfaction and organizational culture is worthwhile from a resourcing perspective and a people development perspective. Every organization has a culture – we believe it is a leadership imperative to install and maintain a culture which ensures you attain the achievements and successes of your utility’s many investments in people, technology and equipment. It is true, organization culture affects everyone, and everyone affects organization culture.

The Loyalty Factor

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If a customer is satisfied, it doesn't necessarily mean he or she is loyal. Satisfaction is about fulfilling promises/expectations; loyalty goes way beyond that by creating exceptional experiences and long-lasting relationships. There is a reason why marketing campaigns strive to build brand loyalty, not brand satisfaction. Measuring customer loyalty in an industry where many customers don't have a choice of providers doesn't make sense. Or does it?

The answer depends on how you define "customer loyalty."

Private industry often equates customer loyalty with basic customer retention. If a customer continues to do business with a company, the customer is, by definition, considered to be loyal. If this definition were applied to many companies in the utility industry, all customers would automatically be considered loyal. As such, measuring customer loyalty would appear to be unnecessary.

Natural monopolies (like LDCs) are not really different in what they should measure except that trying to determine which customers are "loyal" or "at risk" is not about their future behaviour but more about their "attitudinal" loyalty (are they advocates?).

Customer Service, when done well, promotes satisfaction which builds the foundation towards loyalty. Whether a customer is loyal and/or satisfied will be determined by three realities: ANTICIPATION – what your customer anticipates or expects; INTERACTION – what actually happened with/to the customer; and REACTION – how did the customer respond and how did it ultimately make the customer feel.

Perhaps a better or more relevant way for utilities to approach the definition of customer loyalty is to further expand how they think about loyalty. Consider the following definition: Customer loyalty is an emotional disposition on the part of the customer which affects the way(s) in which the customer (consistently) interacts, responds or reacts towards the company – its products & services and its brand.

Some Tips to build loyalty:
- ✓ **Solve problems quickly**
- ✓ **Treat customers right**
- ✓ **Listen to complaints**
- ✓ **Be personal; create a great experience**
- ✓ **Friendly customer service**
- ✓ **Accessible information or help**
- ✓ **Good reputation**
- ✓ **Demonstrate you care**

So, what does it mean to respond favourably to a company? At a basic level, this can mean choosing to remain a customer. As previously mentioned, however, this is essentially a non-issue for many utility companies. It then becomes necessary to think beyond just customer retention. One needs to consider other ways in which customers can respond favourably toward a company.

Other favourable responses or behaviours can be classified into one of three categories that reflect the concept of customer loyalty:

- Participation
- Compliance or Influence
- Advocacy

Specific examples of potential participatory behaviour in the electric utility industry include:

- Signing up for programs which help the customer reduce or manage their energy consumption
- Using the utility as a consultant when selecting energy products and services from a third party
- Participating in pilot programs or research studies.

Specific examples of potential compliance or influence behaviours utility customers might exhibit include:

- Seeking the utility's advice or expertise on an energy-related issue
- Voluntarily cutting back on electricity usage if the utility advised the customer to do so
- Accepting the utility's energy advice or referrals to energy contractors or equipment
- Being influenced by the utility's opinion regarding energy- management advice, equipment, or technologies
- Providing personal information which enables the utility to better serve the customer
- Paying bills online.

Creating customer advocates can be especially important for a company in a regulated industry. In the absence of customer advocates, or worse, in a situation where customers speak unfavourably about a company or actively work to support issues that are counter to those the company supports, companies can suffer a variety of negative consequences like increased business costs, lawsuits, fines, and construction delays. For an electric utility, specific examples of potential advocacy behaviour include:

- Supporting the utility's positions or actions on energy-related public issues, including the environment
- Supporting the utility's position on the location and construction of facilities
- Providing testimonials about positive experiences with the utility.

In sum, loyal behaviour in the utility industry may not be as evident as it is in a more competitive environment. Measuring customer loyalty in a generally non-competitive industry requires one to think about loyalty in non-traditional ways. Customer loyalty is an intangible asset which has positive consequences or outcomes associated with it no matter what the industry. Properly measuring loyalty among utility customers requires thoughtful probing to thoroughly identify the range of participation, compliance, and advocacy behaviours that will ultimately benefit the company in meaningful ways and foster happier and more loyal customers.

Loyalty is driven primarily by a company's interaction with its customers and how well it delivers on their wants and needs.

Customer Loyalty Model

Loyalty is based on likelihood to:

- ***Satisfaction: overall satisfaction***
- ***Commitment: continue as a customer***
- ***Advocacy: willingness to recommend***

The UtilityPULSE Customer Loyalty Performance Score segments customers into four groups: **Secure** – the most loyal - **Still Favorable**, **Indifferent**, and **At risk**.

Secure customers are "very satisfied" overall with their local electricity utility. They have a very high emotional connection with their utility and definitely would recommend their local utility.

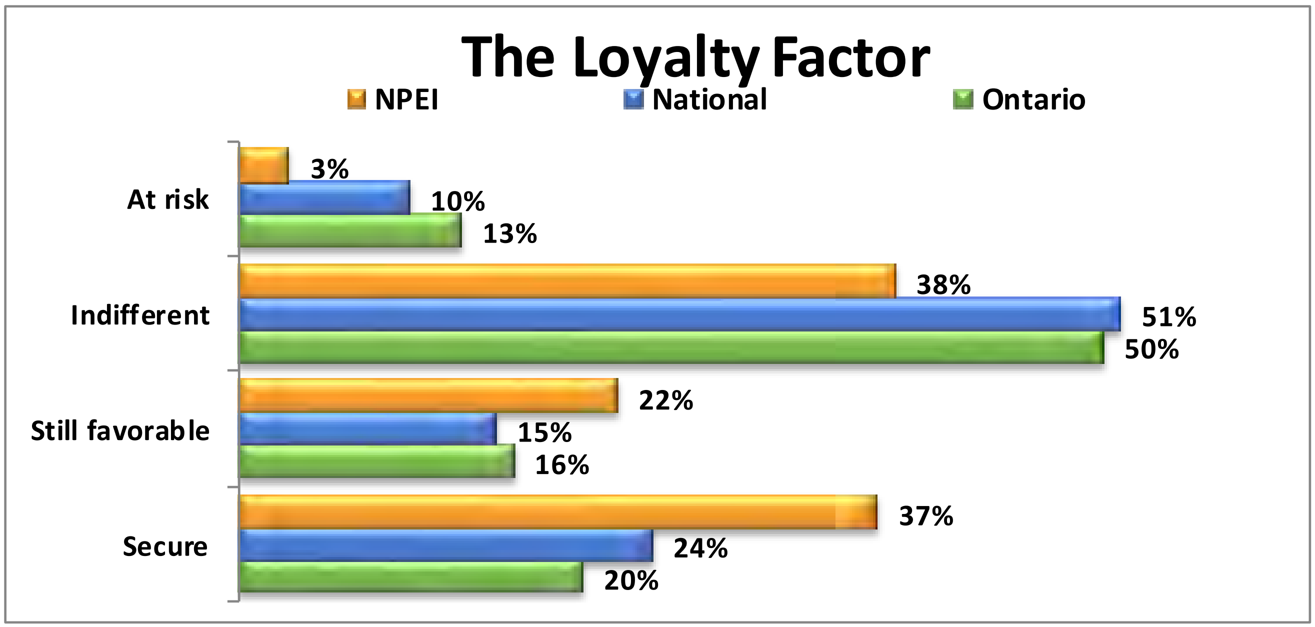
Still favorable customers are "very satisfied" overall, "definitely" or "probably" would recommend their local utility and not switch if they could.

Indifferent customers are less satisfied overall than secure and still-favorable customers and less inclined to recommend their local utility or say they would not switch.

At risk customers, who are "very dissatisfied" with their electric utility, "definitely" would switch and "definitely" would not recommend it.

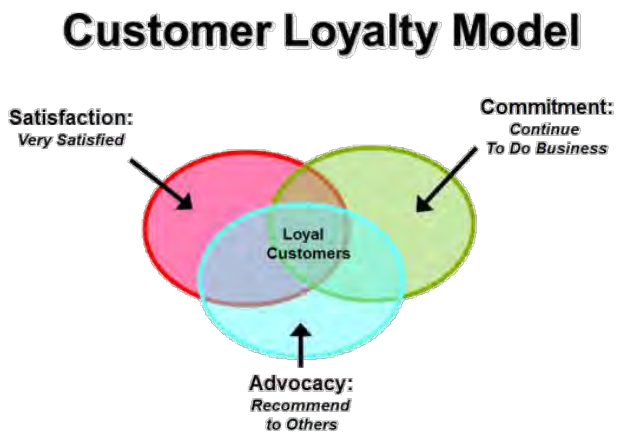
Customer Loyalty Groups				
	Secure	**Favorable**	**Indifferent**	**At Risk**
		NPEI		
2019	37%	22%	38%	3%
2017	20%	15%	53%	12%
2014	18%	9%	61%	11%

Base: total respondents



Base: total respondents

Customer commitment



Customer loyalty is a term which can be used to embrace a range of customer attitudes and behaviours. One of the metrics used to gauge loyalty is the measure of **retention,** or intention to buy again; this loyalty attitude is termed **commitment.** For LDCs commitment is not about behaviour it is about attitude, i.e., do they want to remain your customer.

Customer commitment is a very important driver of customer loyalty in the electricity service industry. In a similar way to trust, commitment is considered an important ingredient in successful relationships. In simpler terms, commitment refers to the motivation to continue to do business with and maintain a relationship with a business partner, i.e. the local utility.

For electric utilities, this measurement is about identifying the number of customers who feel they "want to" vs. "have to" do business with you. Potential benefits of commitment may include word of mouth communications - an important aspect of attitudinal loyalty. Committed customers have been known to demonstrate a number of beneficial behaviours, for example, committed customers tend to:

- Come to you. One of the key benefits of establishing a good level of customer loyalty is customers will come to you when they need a product or service

- Validate information received from 3rd parties with information and expertise that you have
- Try new products/initiatives
- Perhaps they will even trust you when recommendations are made
- Be more price tolerant
- More receptivity of utility viewpoints on various issues
- More tolerance of errors or issues which inevitably take a swipe at the utility
- Stronger levels of perception regarding how the utility is managed.

Though customers cannot physically leave you, they can emotionally leave you, and when they do, it becomes an extreme challenge to garner their participation or support for utility initiatives.

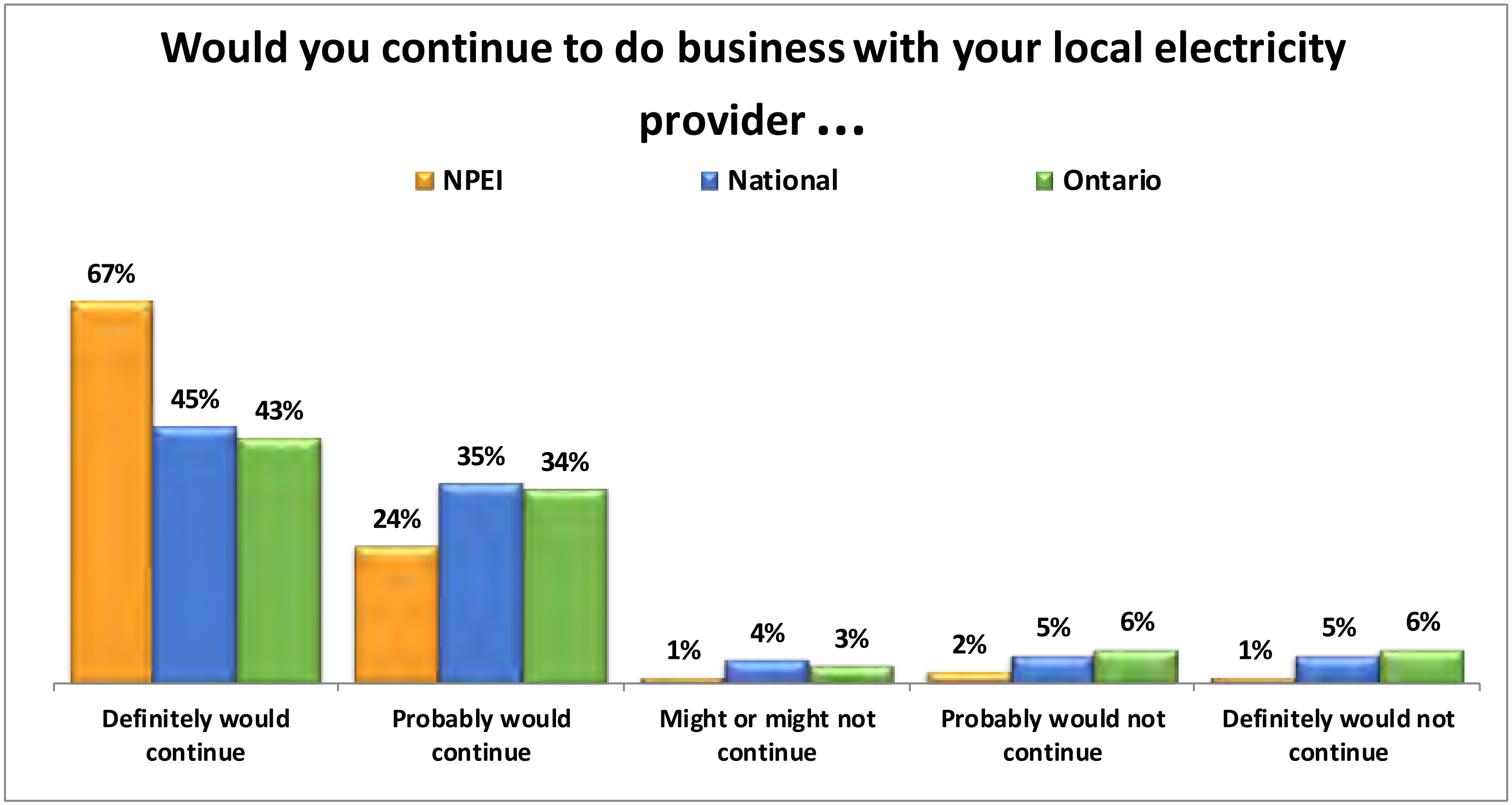
Electricity customers' loyalty – … Is a company that you would like to continue to do business with

	NPEI	National	Ontario
Top 2 Boxes: 'Definitely + Probably' would continue	91%	80%	78%
Definitely would continue	67%	45%	43%
Probably would continue	24%	35%	34%
Might or might not continue	1%	4%	3%
Probably would not continue	2%	5%	6%
Definitely would not continue	1%	5%	6%

Base: total respondents

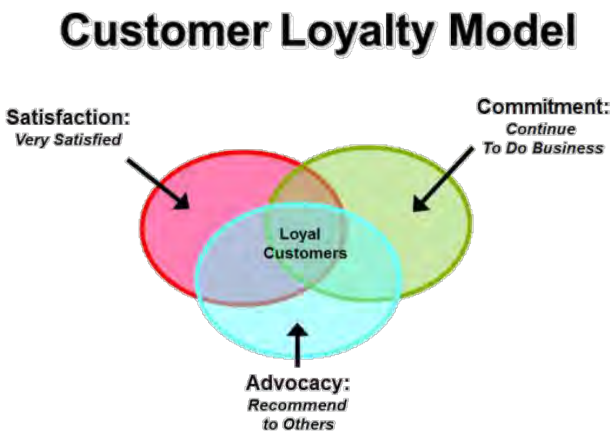
Electricity customers' loyalty – … Is a company that you would like to continue to do business with			
NPEI	**2019**	**2017**	**2014**
Top 2 boxes: 'Definitely + Probably' would continue	91%	79%	79%

Base: total respondents



Base: total respondents

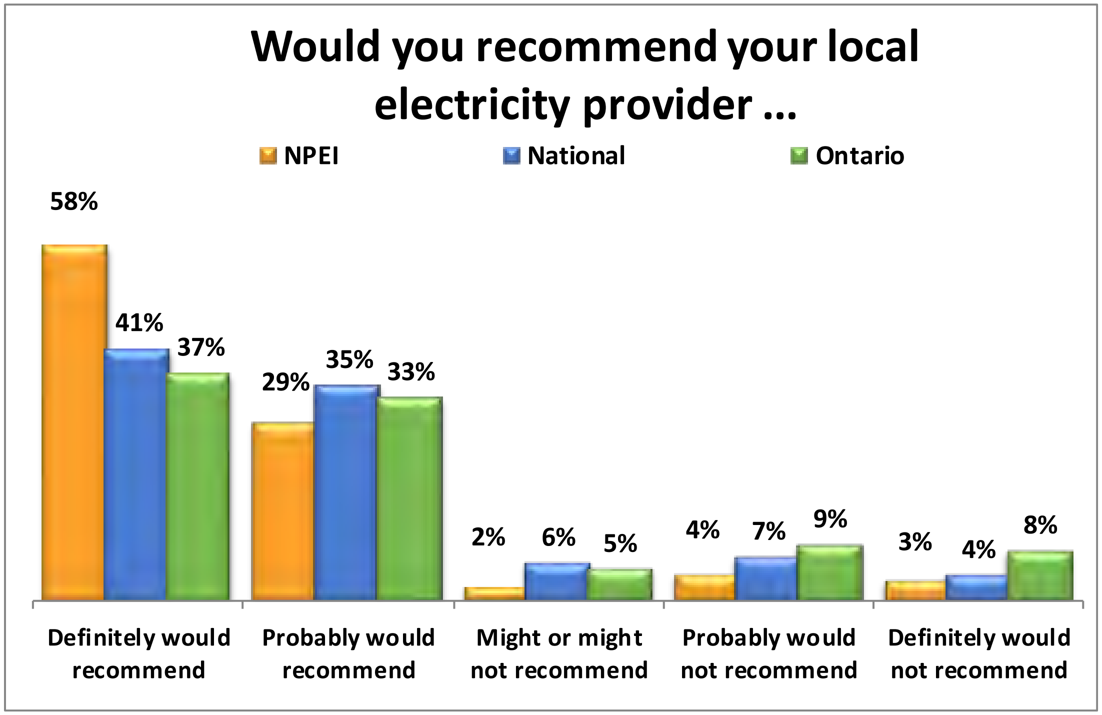
Word of mouth



Advocacy is one of the metrics measured in determining customer loyalty. Essentially, companies believe a loyal customer is one who is spreading the value of the business to others, leading new people to the business and helping the company grow. Customer referrals, endorsements and spreading the word are extremely important forms of customer behaviour. For LDCs this is about generating positive referants about the LDC as a relevant and valuable enterprise.

When customers are loyal to a company, product or service, they not only are more likely to purchase from the company again, but they are more likely to recommend it to others – to openly share their positive feelings and experiences with others. In today's world, thanks to the Internet, they can tell and influence millions of people. The same holds true, if not more, when customers are disloyal. Disgruntled customers could share their negative experiences with an ever-widening audience, jeopardizing a company's reputation and resulting in fewer engaged customers and/or customers who are Favourable or Secure. Secure customers, typically are advocates and they are deeply connected and brand-involved.

Would you tell me if you agree or disagree with the following statement? NPEI is a company that you would recommend to a friend or colleague …



Base: total respondents

Word of mouth communication is a very powerful form of communication and influence. When customers are speaking to other customers (or their peers) it is more credible, goes through less perceptual filters and can enhance the view of services or products better than marketing communication.

There are two forms of word of mouth which utilities need to understand. The first is Experience-based word of mouth which is the most common and most powerful form. It results from a customer's direct experience with the utility or the re-statement of a direct experience from a trusted source.

The second is Relay-based word of mouth. This is when customers pass along important messages to others based on what they have learned through the more traditional forms of communications. For example, if the utility was communicating an offer for "free LED lights" chances are high the offer will be "relayed" to others through word of mouth.

For an electric utility, specific examples of potential positive advocacy behaviour include:

- *Recommending other customers specifically locate in the geographic area which is serviced by that utility*
- *Supporting the utility's positions or actions on energy-related public issues, including the environment*
- *Supporting the utility's position on the location and construction of facilities*
- *Providing testimonials about positive experiences with the utility*

Electricity customers' loyalty – … is a company that you would recommend to a friend or colleague			
	NPEI	**National**	**Ontario**
Top 2 boxes: 'Definitely + Probably' would recommend	87%	76%	70%
Definitely would recommend	58%	41%	37%
Probably would recommend	29%	35%	33%
Might or might not recommend	2%	6%	5%
Probably would not recommend	4%	7%	9%
Definitely would not recommend	3%	4%	8%

Base: total respondents

Electricity customers' loyalty – is a company that you would recommend to a friend or colleague			
NPEI	**2019**	**2017**	**2014**
Top 2 boxes: 'Definitely + Probably' would recommend	87%	71%	72%

Base: total respondents

Our survey research as well as theory backs up the fact that if your customers are willing to endorse you and put their reputation on the line to recommend you, they also trust you and are satisfied with the service you are providing.

Corporate image

Although reputation is an intangible concept, a strong corporate image makes it easier to capture the attention of more customers – more often. Also, to be seen as an independent organization thereby making it easier to introduce new ideas. Employees appreciate a strong corporate image.

Attributes measured in the annual UtilityPULSE survey which are strongly linked to a utility's image include:

Marketing – Communications			
	NPEI	**National**	**Ontario**
Topics which require more pro-active communication			
Cost of electricity is reasonable when compared to other utilities	72%	66%	61%
Provides good value for money	81%	72%	71%
Operates a cost-effective electricity distribution system	82%	70%	71%
Provides information to help customers reduce their costs	80%	78%	78%
Adapts well to changes in customer expectations	84%	73%	72%
Topics that your utility scores very well on			
Delivers on its service commitments	91%	86%	86%
Electricity safety is a top priority	89%	87%	86%
Quickly handles outages and restores power	91%	87%	86%
Standard of reliability delivering electricity that meets expectations	92%	88%	88%
Provides consistent, reliable energy	94%	89%	90%

Base: total respondents with an opinion

Corporate Credibility & Trust

Credibility is a judgment, customers and others make about whether a person or an organization has the competencies and experience to do what they promise to do. Trust, is a feeling or belief, that a person or an organization they are dealing with is doing so in an honest, open manner with no hidden agendas. How customers and other stakeholders respond to your communications is affected by the person's perception. Without credibility and trust, everything you say to customers, employees, and others can be questioned.

Of paramount importance to maintaining credibility & trust is effectively managing expectations—customers, employees and other stakeholders that matter to the business of the LDC. A key to this is open and honest communications. An important benefit of having a high degree of credibility & trust is, authentic collaboration can become a reality. Credibility & trust is a powerful currency for building relationships. Credibility & trust are outcomes based on what the LDC actually does, not what it might be doing.

Attributes strongly linked to Credibility & Trust			
	NPEI	National	Ontario
Overall the utility provides excellent quality services	90%	85%	86%
Keeps its promises to customers and the community	88%	79%	80%
Customer-focused and treats customers as if they're valued	87%	80%	79%
Is a trusted and trustworthy company	90%	83%	82%

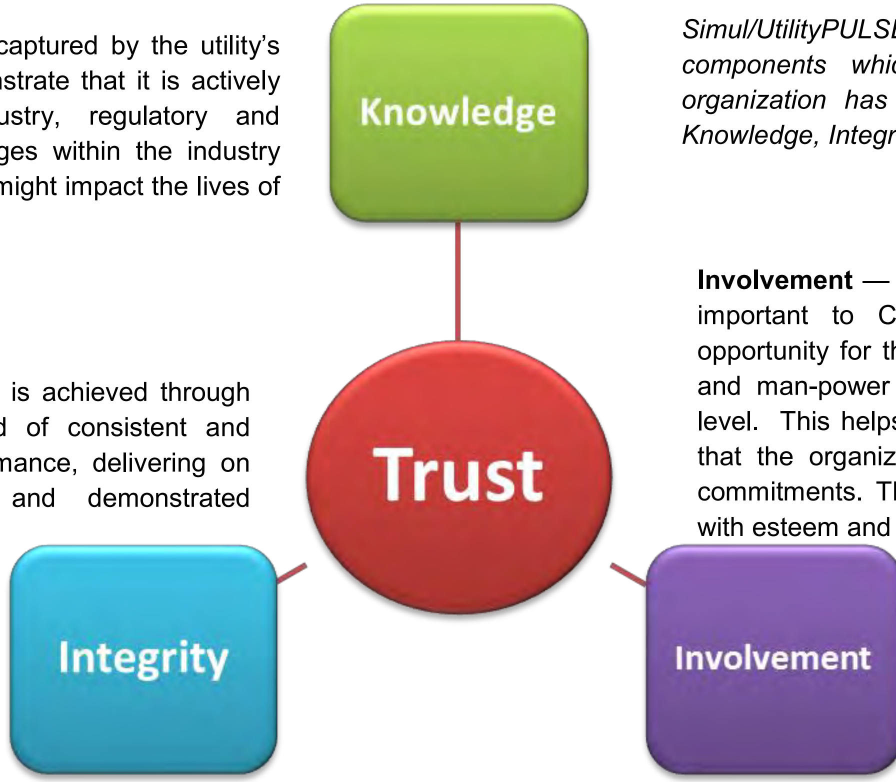
Base: total respondents with an opinion

Simul/UtilityPULSE research shows the under-pinning components which lead customers to believe an organization has credibility and can be trusted are: Knowledge, Integrity, Involvement and Trust.

Knowledge is captured by the utility's ability to demonstrate that it is actively aware of industry, regulatory and economic changes within the industry and how these might impact the lives of customers.

Trust — Trust is achieved through a track record of consistent and reliable performance, delivering on commitments and demonstrated accountability.

Involvement — Corporate Involvement is increasingly important to Canadian communities as it is an opportunity for their local utility to use their resources and man-power to benefit people at the community level. This helps to build credibility as customers see that the organization is acting and delivering on its commitments. This helps customers regard the utility with esteem and respect.



Integrity is established by demonstrating adherence to a code of conduct. It requires consistently acting in accordance with the values and goals that have been communicated to customers.

Credibility and Trust Index

NPEI 88%

Ontario 81%

National 82%

How can service to customers be improved?

The electric utility industry is in a state of continuous transformation. External factors - including shifts in governmental policies, a global thrust to conserve energy, advances in new technologies and power generation are driving massive changes throughout the industry. LDCs of today and the future can also expect a much more intense level of customer involvement. UtilityPULSE research shows customers want to be heard.

Despite all the talk today centered on quality, new processes and systems, continuous improvement, and costs, unless all of this is aimed at obtaining customer satisfaction it will not be worth much over the longer term.

Qualitative questions typically do not provide the statistical richness which is associated with a quantitative question. However, they do provide words, phrases, insights into the thinking patterns and/or feelings of customers. This means qualitative questions have an interpretive richness that assists in deriving meaning from the survey. The broader range of suggestions we are getting when conducting the survey is a sign the customer base is becoming more and more segmented. Not all customers are the same.

The struggle for electric utilities is finding the right balance between cost-effective, technology-enabled approaches to customer services and person-to-person contact.

Customers want their utility to focus on what matters most; offer products and services which “make a difference in their life”, “gives them peace of mind” and “delivered by trusted and credible people”.

And we are interested in knowing what you think are the one or two most important things NPEI could do to improve service to their customers?

One or two most important things ‘your local utility’ could do to improve service	
	NPEI
Better prices/lower rates	41%
Longer office hours	15%
Information & incentives on energy conservation	8%
Improve/simplify/clarify billing	5%
Improve reliability of power	4%
Better maintenance/repair street lights	3%
Change peak hours/extend time for off-peak	3%
Restore power faster	2%
More incentives and/or rebate offers	2%

Base: total respondents with suggestions

What do customers think about electricity costs?

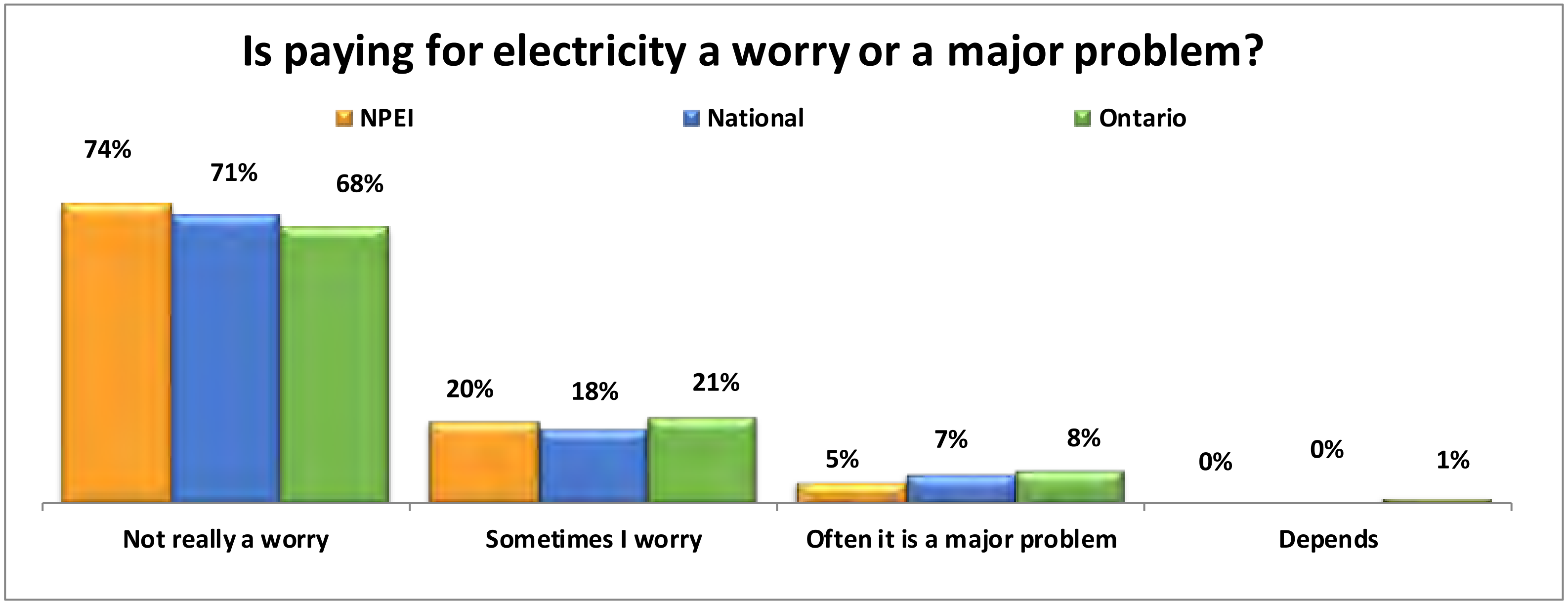
At the height of the 'anger' stage for many customers, the UtilityPULSE database showed 31% of survey respondents said they sometimes worried about paying their bill. Customers felt they were paying more but not getting more, especially disconcerting when wages and inflation were hovering around the 2% mark. Five years earlier that number was 21%. The 2017, 25% reduction in costs, coupled with a promise to further reduce the cost and a better economy has helped to move the number back to 21% in Ontario. This is a huge change.

Next, I am going to read a number of statements people might use about paying for their electricity. Which one comes closest to your own feelings, even if none is exactly right? Paying for electricity is not really a worry, Sometimes I worry about finding the money to pay for electricity, or Paying for electricity is often a major problem?

Is paying for electricity a worry or a major problem?

	Not a worry	Sometimes	Often	Depends
NPEI	74%	20%	5%	0%
National	71%	18%	7%	0%
Ontario	68%	21%	8%	1%

Base: total respondents



Base: total respondents

Is paying for electricity a worry or a major problem?				
	Not a worry	Sometimes	Often	Depends
		NPEI		
<$30,000	55%	31%	13%	0%
$30<$75,000	71%	26%	2%	0%
$75,000+	87%	11%	2%	0%

Base: total respondents

What do small commercial customers think?

Based on Fall 2018 data in the UtilityPULSE database, small commercial customers have relatively similar views about their utility. The tables associated with this report will contain your specific information as it relates to residential and commercial customers. A word of caution, smaller data samples create greater swings or spreads in the data, hence mitigating the effect of a small data sample by using the Fall 2018 UP database.

Small Commercial Customer (General Service < 50kW Demand)

A small commercial customer is defined by the OEB as a non-residential customer in a less than 50 kW demand rate class. These customers are similar to the residential customer in that their bill does not have a demand component to it and their charges are based upon KWH of consumption. Most of these customers would occupy small storefront locations or offices

An area of concern is about the LDC's ability to "target" its communications to the type of business. Beyond having a contact telephone number, company name and address there isn't much "knowledge" about the small commercial customer. In a time when "targeted" communication is important, knowing the type of category of small commercial account would assist LDCs in delivering meaningful messages in an effective way. This could be particularly important in the area of energy conservation, i.e., pulling together messages and programs for specific types of businesses. After all, a small restaurant is different from a small accounting office.

Satisfaction: Pre & Post		
Satisfaction (Top 2 Boxes: 'very + somewhat satisfied')	**Residential**	**Commercial**
Initially	93%	93%
End of Interview	92%	93%

Base: total respondents from the 2018 UtilityPULSE Database

As it relates to the six attributes associated with customer service:

Very or fairly satisfied with…	Residential	Commercial
The time it took to contact someone	73%	78%
The time it took someone to deal with your problem	71%	73%
The helpfulness of the staff who dealt with your problem	75%	81%
The knowledge of the staff who dealt with your problem	74%	77%
The level of courtesy of the staff who dealt with your problem	82%	88%
The quality of information provided by the staff member	74%	75%

Base: total respondents from the 2018 UtilityPULSE Database

Killer B's: Outages & Bills problems		
	Residential	**Commercial**
Respondents with outage problems	42%	39%
Respondents with billing problems	9%	8%

Base: total respondents from the 2018 UtilityPULSE Database

Overall satisfaction with most recent experience		
	Residential	**Commercial**
Top 2 Boxes: 'very + somewhat satisfied'	77%	77%
Bottom 2 Boxes: 'somewhat + very dissatisfied'	19%	20%

Base: total respondents from the 2018 UtilityPULSE Database

Comparisons between Residential and Commercial		
Loyalty Groups	**Residential**	**Commercial**
Secure	30%	32%
Still Favourable	17%	18%
Indifferent	46%	43%
At risk	7%	7%

Base: total respondents from the 2018 UtilityPULSE Database

Loyalty Model Factors		
	Residential	**Commercial**
Very/somewhat satisfied	93%	93%
Definitely/probably would continue	86%	87%
Definitely/probably would recommend	79%	83%

Base: total respondents from the 2018 UtilityPULSE Database

Important attributes which describe operational effectiveness		
	Residential	**Commercial**
Provides consistent, reliable electricity	92%	91%
Delivers on its service commitments to customers	89%	88%
Accurate billing	89%	88%
Quickly handles outages and restores power	91%	91%
Makes electrical safety a top priority	90%	90%
Is efficient at managing the electricity distribution system	86%	87%
Is a company that is 'easy to do business with'	86%	87%
Operates a cost-effective electricity distribution system	74%	74%
Standard of reliability meets expectations	91%	90%

Base: total respondents from the 2018 UtilityPULSE Database with an opinion

Important attributes which shape perceptions about service quality and value		
	Residential	Commercial
Is pro-active in communicating changes and issues which may affect customers	81%	81%
Provides good value for money	74%	75%
Customer-focused and treats customers as if they're valued	84%	83%
Deals professionally with customers' problems	87%	87%
Spends money prudently	82%	81%
Quickly deals with issues that affect customers	86%	85%
Provides information and tools to help manage electricity consumption	83%	79%
Provides information to help customers reduce their electricity costs	79%	75%
The cost of electricity is reasonable when compared to other utilities	64%	60%

Base: total respondents from the 2018 UtilityPULSE Database with an opinion

Important attributes which shape perceptions about corporate image		
	Residential	Commercial
Is a respected company in the community	87%	87%
A leader in promoting energy conservation	79%	79%
Keeps its promises to customers and the community	85%	84%
Is a socially responsible company	84%	85%
Is a trusted and trustworthy company	87%	87%
Adapts well to changes in customer expectations	79%	80%
Overall the utility provides excellent quality services	89%	87%

Base: total respondents from the 2018 UtilityPULSE Database with an opinion

Importance of online access for the following features:		
Top 2 Boxes: 'very + somewhat important'	**Residential**	**Commercial**
Reporting or inquiring about an issue	48%	52%
Researching information about energy conservation	40%	45%
Having a web chat feature on the website	20%	28%
Automated alerts when electricity usage exceeds a prearranged threshold	21%	30%
Review and pay your bill online (through utility's website)	44%	48%
Power outage alerts	65%	72%
Tools and calculators to help you manage your electricity consumption	30%	37%
Comparison of your electricity consumption with your neighbours	18%	26%
Automated alert to predict your upcoming bill	33%	37%
Automated alert to remind you of your bill due date	33%	37%

Base: total respondents from the 2018 UtilityPULSE Database

Preferred method of communication to receive notice of a billing issue		
	Residential	**Commercial**
Telephone	57%	55%
Voice Mail	2%	2%
Text	8%	4%
Email	33%	39%
Don't know	1%	1%

Base: total respondents from the 2018 UtilityPULSE Database

Method of communication Customers prefer their LDC uses during an UNPLANNED OUTAGE		
	Residential	**Commercial**
Recorded telephone message	34%	31%
Email notice	19%	29%
Posted on utility's website	4%	6%
Social media	5%	5%
Local radio	5%	5%
Local TV	3%	1%
Text message	25%	19%
Alert on APP	2%	2%

Base: total respondents from the 2018 UtilityPULSE Database

Method of communication Customers prefer their LDC uses about general news		
	Residential	**Commercial**
Recorded telephone message	23%	16%
Email notice	38%	49%
Posted on utility's website	6%	8%
Social media	6%	7%
Local radio	5%	5%
Local TV	5%	4%
Text message	10%	7%
Alert on APP	1%	2%

Base: total respondents from the 2018 UtilityPULSE Database

Satisfaction with information provided		
Top 2 Boxes:'very + fairly satisfied'	**Residential**	**Commercial**
The amount of information available to you about energy conservation	82%	80%
The quality of information available when outages occur	73%	77%
The electricity safety education provided to the public	74%	76%
The timeliness and relevance of information for things such as planned outages, construction activity, tree trimming.	77%	80%

Base: total respondents from the 2018 UtilityPULSE Database

Access to services		
Top 2 Boxes: 'very + somewhat satisfied'	**Residential**	**Commercial**
The availability of call-centre staff Monday to Friday	58%	66%
The 24/7 availability of system operators to respond to respond to outages	78%	88%
The online self-serve options for managing your account	56%	72%
The online self-serve options for request services	48%	70%

Base: total respondents from the 2018 UtilityPULSE Database

Method

The findings in this report are based on telephone interviews conducted for Simul Corp. / UtilityPULSE by Logit Group between June 3 - June 12, 2019, with 407 respondents who pay or look after the electricity bills from a list of residential and small and medium-sized business customers supplied by NPEI.

The sample of phone numbers chosen was drawn randomly to ensure each business or residential phone number on the list had an equal chance of being included in the poll.

The sample was stratified so that 85% of the interviews were conducted with residential customers and 15% with commercial customers.

In sampling theory, in 19 cases out of 20 (95% of polls in other words), the results based on a random sample of 407 residential and commercial customers will differ by no more than ±4.90 percentage points where opinion is evenly split.

This means you can be 95% certain that the survey results do not vary by more than 4.90 percentage points in either direction from results that would have been obtained by interviewing all NPEI residential and small and medium-sized commercial customers if the ratio of residential to commercial customers is 85%:15%.

The margin of error for the sub-samples is larger. To see the error margin for subgroups, use the calculator at http://www.surveysystem.com/sscalc.htm.

Interviewers reached 3,965 households and businesses from the customer list supplied by NPEI. The 407 who completed the interview represent a 10% response rate.

The findings for the Simul/UtilityPULSE National Benchmark of Electric Utility Customers are based on telephone interviews conducted with adults throughout the country who are responsible for paying electric utility bills. The ratio of 85% residential customers and 15% small and medium-sized business customers in the National study reflects the ratios used in the local community surveys. The margin of error in the National poll is ±2.95 percentage points at the 95% confidence level.

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

The data were weighted in each region of the country to match the regional shares of the population.

The margin of error refers only to sampling error; other non-random forms of error may be present. Even in true random samples, precision can be compromised by other factors, such as the wording of questions or the order in which questions were asked.

Random samples of any size have some degree of precision. A larger sample is not always better than a smaller sample. The important rule in sampling is not how many respondents are selected but how they are selected. A reliable sample selects poll respondents randomly or in a manner which ensures that everyone in the population being surveyed has an equal chance of being selected.

How can a sample of only several hundred truly reflect the opinions of thousands or millions of electricity customers within a few percentage points?

Measures of sample reliability are derived from the science of statistics. At the root of statistical reliability is probability, the odds of obtaining a particular outcome by chance alone. For example, the chances of having a coin come up heads in a single toss are 50%. A head is one of only two possible outcomes.

The chance of getting two heads in two coin tosses is less because two heads are only one of four possible outcomes: a head/head, head/tail, tail/head and tail/tail.

But as the number of coin tosses increases, it becomes increasingly more likely to get outcomes that are either close to or exactly half heads and half tails because there are more ways to get such outcomes. Sample survey reliability works the same way but on a much larger scale.

As in coin tosses, the most likely sample outcome is the true percentage of whatever we are measuring across the total customer base or population surveyed. Next most likely are outcomes very close to this true percentage. A statement of the potential margin of error or sample precision reflects this.

Some pages in the computer tables also show the standard deviation (S.D.) and the standard error of the estimate (S.E.) for the findings. The standard deviation embraces the range where 68% (or approximately two-thirds) of the respondents would fall if the distribution of answers were a normal bell-shaped curve. The spread of responses is a way of showing how much the result deviates from the "standard mean" or average. In the NPEI data on corporate image, Simul converted the answers to a point scale with 4 meaning agree strongly, 3 meaning agree somewhat and so on (see in the computer tables).

For example, the mean score is 3.74 for providing consistent, reliable electricity. The average is 3.21 for providing information to help customers reduce their energy costs.

For reliable electricity, the standard deviation is 0.58. For providing information to help customers reduce their energy costs, the S.D. is 0.86. These findings mean there is a wider range of opinion – meaning less consensus – about whether help to reduce energy costs than about whether NPEI energy supplies are reliable.

Beneath the S.D. in the tables is the standard error of the estimate. The S.E. is a measure of confidence or reliability, roughly equivalent to the error margin cited for sample sizes. The S.E. measures how far off the sample's results are from the standard deviation. The smaller the S.E., the greater the reliability of the data.

In other words, a low S.E. indicates the answers given by respondents in a certain group (such as residential bill payers or women) do not differ much from the probable spread of the answers "predicted" in sampling and probability theory.

In certain instances, all of the sub-datasets from the entire UtilityPULSE database for 2018 were concatenated in order to use the average of all the control samples for comparison. The cumulated population base for these questions was in excess of 9,000.

Good things happen when workplaces work. You'll receive both strategic and pragmatic guidance about how to improve Customer satisfaction & Employee engagement with leaders who lead and a front-line which is inspired. We provide training, consulting, surveys, diagnostic tools, and keynotes. The electric utility industry is a market segment we specialize in. Both large and small utilities have received actionable insights. For 21 years we have been talking to 1000's of utility customers in Ontario and across Canada and we have expertise which is beneficial to every utility.

Culture, Leadership & Performance – Organizational Development	**Focus Groups, Surveys, Polls, Diagnostics**	**Customer Service Excellence**
Leadership development	Diagnostics ie. Change Readiness, Leadership Effectiveness, Managerial Competencies	Service Excellence Leadership
Strategic Planning	Surveys & Polls	Telephone Skills
Teambuilding	Customer Satisfaction and Loyalty Benchmarking Surveys	Customer Care
Organizational Culture Transformation	Organization Culture Surveys	Dealing with Difficult Customers

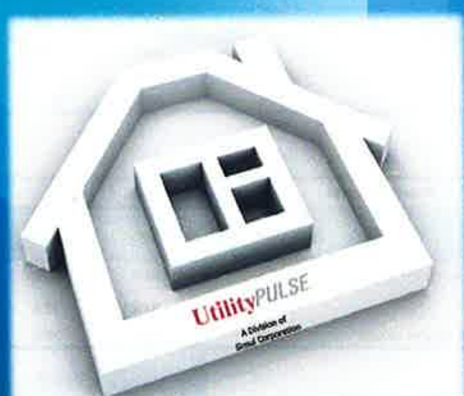
Benefit from our expertise in Customer Satisfaction, Leadership development, Strategy development or review, and Front-line & Top-line driven-change. We're experts in helping you assess and then transform your organization's culture to one where achieving goals while creating higher levels of customer satisfaction is important. Anyone can present data, or design programs – we believe having an understanding of the industry before doing so is crucial. Call us when creating an organization where more employees satisfy more customers more often, is important.

Your personal contact is:

Sid Ridgley, CSP

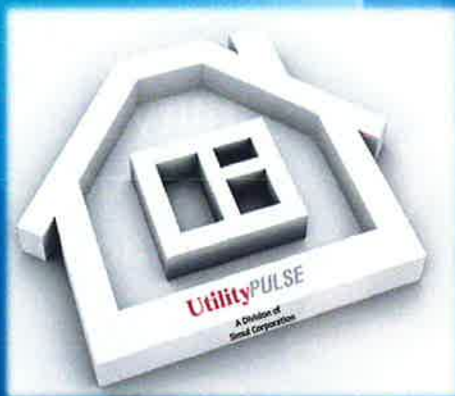
Phone: (905) 895-7900 x 29 E-mail: sridgley@simulcorp.com

Electric Utility Customer Satisfaction Survey



- Based on telephone interviews of *403 respondents* who pay or look after the electricity bills for *NPEI*
- Note: A sample size of 403 will provide confidence level of 95% (+/-4.9%)
- Customers surveyed were based on a *random sample* approach
- 1,775 households and small businesses were contacted, 403completed interviews; response rate is 23%
- The following *segments* were surveyed:
  - Residential – 85%
  - Commercial – 15%
- NPEI's customers participated in an *"in-depth"* Customer Satisfaction Telephone Survey
- National benchmark data has been refined to reflect the demographic mix in Canada
- Results of the Utility*PULSE* Report Card® are computed by formulas which map the attributes of corporate image to customer satisfaction and loyalty
- Comparator data:
  - Ontario benchmark
  - National benchmark
  - UtilityPULSE data base for 2017

Electric Utility
Customer Satisfaction Survey



- The LDC industry continues to be affected by events outside of the control of the LDC. Those events affect a customer's feelings as they relate to trust and credibility.
- More customers indicate they worry about paying their bill.
- The Ontario government has recognized the stress that many Ontarians face regarding their bill. As such, has committed to lowering the costs of electricity. While relief will be welcomed, the reality is "worry" has turned to "anger" for many customers. Angry people have long memories and do not forgive easily.
- Customers value the opportunity to have their voice heard. There will be a very wide range of opinion in the customers voice about virtually every topic.
- Customers have a perception about the electricity industry as a whole. That image influences how people think and feel about their LDC. For example there is a 12 point drop in satisfaction levels between customers who are "confident" vs "unconfident" about the industry to meet their expectations.

NPEI had been given excellent scores, on trust, satisfaction, and reliability.

Operational & Representative Attributes

Operational			
Top 2 Boxes: 'Strongly + Somewhat agree'	**NPEI**	**National**	**Ontario**
Provides consistent, reliable electricity	91%	89%	89%
Quickly handles outages and restores power	92%	87%	85%
Accurate billing	84%	83%	80%

Base: total respondents with an opinion

Representatives			
Top 2 Boxes: 'Strongly + Somewhat agree'	**NPEI**	**National**	**Ontario**
Deals professionally with customers problems	84%	83%	81%
Is 'easy to do business with'	81%	81%	77%
Customer-focused and treats customers as if they're valued	80%	75%	73%

Base: total respondents with an opinion

What Our Customers Say...

91%

"Provides consistent, reliable electricity..."

4

Credibility and Trust Rating:

Demonstrating Credibility and Trust
Knowledge
The utility is seen as being knowledgeable about the services it provides, about what is happening in the industry, and how customers can reduce costs or create more value.
Integrity
The utility is seen as an organization that will act in the best interests of its customers and can be counted on to provide services and resolve problems in a professional manner.
Involvement
The utility is actively involved in the industry, in the community and in things that affect the customer.
Trust
The utility is an organization that can be trusted and is worthy of respect.

Overall NPEI 82%
[Ontario 77%; National 80%]

80%

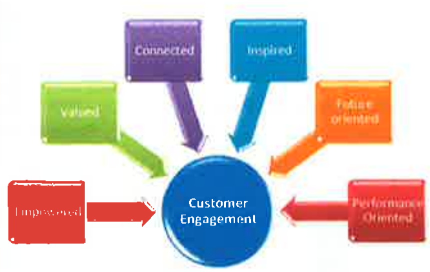
"Keeps its promises to customers and the community..."

Base: total respondents

CCEI: Customer Centric Engagement Index

Customer Centric Engagement Index (CCEI)			
	NPEI	National	Ontario
CCEI	81%	78%	74%

Base: total respondents



81%

"... CCEI: Customer Centric Engagement Index..."

CEPr: Customer Experience Performance rating

Customer Experience Performance rating (CEPr)			
	NPEI	National	Ontario
CEPr	83%	82%	80%

Base: total respondents

At the heart of the CEPr are 4 central questions:

Professional Customer Care

1. *Are interactions with the organization professional and productive?*
2. *Is the organization 'easy to deal with'?*

3. *Does the organization effectively meet your needs?*
4. *Does the organization provide high quality services?*

83%

"CEPr: Customer experience rating..."

7

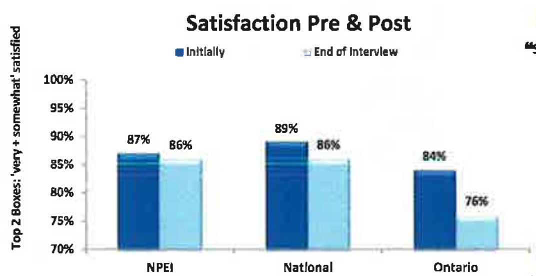
Customer Satisfaction: PRE

Electricity bill payers who are 'very or fairly' satisfied with...			
Top 2 Boxes: 'very + fairly satisfied'	NPEI	National	Ontario
PRE: Initial Satisfaction Scores	87%	89%	84%
POST: End of Interview	86%	86%	76%

Base: total respondents

PRE 87%

"SATISFIED: Beginning of Interview"



POST 86%

"SATISFIED: End of Interview"

Base: total respondents

8

Customer Satisfaction

SATISFACTION SCORES – Electricity customers' satisfaction [kwh usage]			
Top 2 Boxes: 'very + fairly satisfied'	kWh Group 1	kWh Group 2	kWh Group 3
Satisfaction Scores	90%	89%	80%

Base: total respondents

SATISFACTION SCORES – Electricity customers' satisfaction [Income]			
Top 2 Boxes: 'very + fairly satisfied'	<$30K	$30 – 75K	$75K +
Satisfaction Scores	86%	88%	87%

Base: total respondents

SATISFACTION SCORES – Electricity customers' satisfaction		
Top 2 Boxes: 'very + fairly satisfied'	Residential	Small Commercial
Satisfaction Scores	87%	90%

Base: total respondents

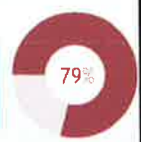
9

Customer Commitment

"Is a company that you would like to continue to do business with"

Electricity customers' loyalty – ... is a company that you would like to continue to do business with			
	NPEI	National	Ontario
Top 2 Boxes: 'Definitely + Probably' continue	79%	78%	69%

Base: total respondents



Customer Advocacy

"Is a company that you would recommend to others"

Electricity customers' loyalty – ... is a company that you would recommend to others			
	NPEI	National	Ontario
Top 2 Boxes: 'Definitely + Probably' recommend	71%	71%	59%

Base: total respondents

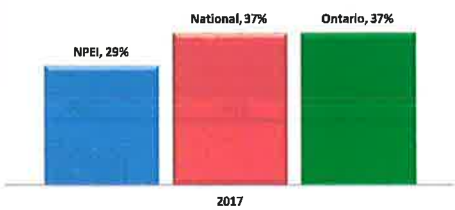
10

Outage Problems (last 12 months)

Percentage of Respondents indicating that they had a Blackout or Outage problem in the last 12 months	NPEI	National	Ontario
2017	29%	37%	37%
2016	-	53%	51%
2015	-	47%	49%
2014	51%	41%	35%
2013	-	44%	46%

Base: total respondents/ (-) not a participant of the survey year

Blackout or Outage Problems in the last 12 months



Base: total respondents/ (-) not a participant of the survey year

What Our Customers Say...

92%

"... Quickly handles outages and restores power..."

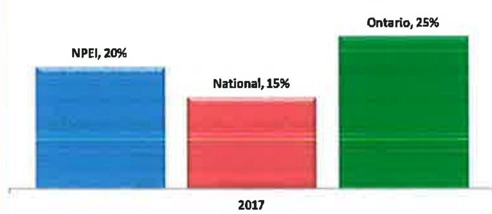
11

Billing Problems (last 12 months)

Percentage of Respondents indicating that they had a Billing problem in the last 12 months	NPEI	National	Ontario
2017	20%	15%	25%
2016	-	9%	15%
2015	-	16%	25%
2014	18%	8%	10%
2013	-	12%	13%

Base: total respondents/ (-) not a participant of the survey year

Billing Problems in the last 12 months



Base: total respondents/ (-) not a participant of the survey year

What Our Customers Say...

84%

"... Provides accurate billing..."

12

Types of billing problems

Types of Billing Problems

	NPEI
The amount owed was too high	78%
The bill arrived late	12%
Complaint about rates or charges	5%
Wrong information on bill	2%
The bill was difficult to understand	1%
Payment incorrectly recorded	1%

Base: total respondents with billing problems

78%

"... Amount owed was too high ..."

13

Bill Payer's Problems and Problem Resolution

31% of NPEI respondents with an outage problem did contact the utility.

30% of NPEI respondents with a billing problem did contact the utility.

Respondents who said they contacted the utility were also asked "Do you consider the problem solved or not solved?" 65% of your LDC's respondents said their problem was solved.

14

Customer Service

Customer Service Expectations	NPEI	National	Ontario
The time it took to contact someone	73%	67%	63%
The time it took someone to deal with your problem	68%	64%	60%
The helpfulness of the staff who dealt with you	70%	67%	64%
The knowledge of the staff who dealt with you	73%	63%	59%
The level of courtesy of the staff who dealt with you	84%	74%	69%
The quality of information provided by the staff who dealt with you	76%	65%	64%

Base: total respondents

Customer Service

84%

"Deals professionally with customers' problems..."

Base: total respondents

15

Recent Experience: Satisfaction

Overall satisfaction with most recent experience			
	NPEI	National	Ontario
Top 2 Boxes: 'very + fairly satisfied'	70%	72%	63%

Base: total respondents

Every touch point with customers on the phone, website or in-person influences what customers think and feel about the organization.

16

Customer Service Quality

Customer Service Quality	NPEI	National	Ontario
Deals professionally with customers' problems	84%	83%	81%
Customer-focused and treats customers as if they're valued	80%	75%	73%
Is a company that is 'easy to do business with'	81%	81%	77%

Base: total respondents with an opinion

"What do our **customers** want?"

- *Their problem solved quickly*
- *To have personal interaction with a customer care representative*
- *To speak with a knowledgeable and courteous customer care representative*

What Our Customers Say...

80%

"... Customer-focused and treats customers as if they're valued..."

17

Report Card: A

NPEI's UtilityPULSE Report Card®		NPEI	Ontario
	Category	NPEI	Ontario
1	**Customer Care**	**B**	**C+**
	Price and Value	C+	C
	Customer Service	B+	B
2	**Company Image**	**A**	**B**
	Company Leadership	B+	B
	Corporate Stewardship	A	B
3	**Management Operations**	**A**	**A**
	Operational Effectiveness	A	B+
	Power Quality and Reliability	A +	A
	OVERALL	A	B

"B ... Customer Care"

"A ... Company Image"

"A ... Management Operations"

18

LDC Attributes

Low scoring			
Top 2 Boxes: 'Strongly + Somewhat agree'	**NPEI**	**National**	**Ontario**
Adapts well to changes in customer expectations	74%	71%	68%
Operates a cost effective electricity system	65%	70%	56%
Provides good value for your money	59%	62%	56%
Cost of electricity is reasonable when compared to other utilities	48%	61%	48%

Base: total respondents with an opinion

High Scoring			
Top 2 Boxes: 'Strongly + Somewhat agree'	**NPEI**	**National**	**Ontario**
Provides consistent, reliable electricity	91%	89%	89%
Makes electricity safety a top priority for employees and contractors	90%	87%	86%
Quickly handles outages and restores power	92%	87%	85%
Has a standard of reliability that meets expectations	89%	88%	86%

Base: total respondents with an opinion

19

Technology & the Future

The effect of technological changes on people's lives will lead to a future that is ...				
Top 2 Boxes: 'Strongly + Somewhat agree'	**Overall**	**< $30k**	**$30k < $75k**	**$75k+**
Mostly better	56%	55%	57%	66%
Mostly worse	9%	7%	9%	6%
Neither	26%	26%	22%	22%
Don't know	9%	12%	12%	5%

Base: total respondents

The effect of technological changes on people's lives will lead to a future that is ...				
Top 2 Boxes: 'Strongly + Somewhat agree'	**Overall**	**18-34**	**35-54**	**55+**
Mostly better	56%	74%	61%	51%
Mostly worse	9%	3%	10%	9%
Neither	26%	21%	24%	25%
Don't know	9%	3%	5%	4%

Base: total respondents

What Our Customers Say...

56%

"The effect of technological changes on people's lives will lead to a future that is ... MOSTLY BETTER"

20

Use of Technology

79%	58%	67%	52%
• Access the internet for information	• Have a social media account	• Use online banking	• Shop online

What Our Customers Say...

67%

"Use online banking"

Base: total respondents

21

Importance of Online Access

Importance of online access for the following features: Top 2 Boxes: 'very + somewhat important'	NPEI	UtilityPULSE Database
Reporting or inquiring about an issue	72%	71%
Researching information about energy conservation	78%	79%
Having a web chat feature on the website	53%	50%
Automated alerts when electricity usage exceeds a prearranged threshold	76%	71%
Review and pay your bill online (through utility's website)	71%	68%
Power outage alerts	78%	80%
Tools and calculators to help you manage your electricity consumption	70%	67%
Comparison of your electricity consumption with your neighbours	53%	51%
Automated alert to predict your upcoming bill	64%	59%
Automated alert to remind you of your bill due date	64%	59%

Base: total respondents / total respondents from the 2017 UtilityPULSE Database

Online!

What Our Customers Say...

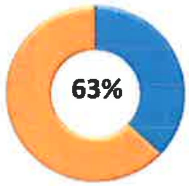
78%

"Feel it is 'important' to have Power Outage alerts ..."

22

Confidence in the industry

'Customers are well served by the electricity system in Ontario' – do you agree?



- 63% Agree ('strongly + somewhat') customers are well served by the electricity system in Ontario
- 4% neither agree or disagree
- 31% Disagree ('strongly + somewhat') they are well served
- 1% did not render an opinion or did not know

'Customers are well served by the electricity system in Ontario' – do you agree?

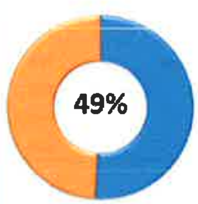
	NPEI	Ontario	UtilityPULSE Database
Top 2 Boxes: 'Strongly + Somewhat Agree'	63%	55%	56%

Base: total respondents / total respondents from the 2017 UtilityPULSE Database

23

Confidence in the industry

'Customers are confident in the electricity industry's ability to meet their future expectations regarding quality, reliability and price' – do you agree?



- 49% Agree ('strongly + somewhat') customers are confident that the electricity industry has the ability to meet future expectations regarding quality, reliability and price
- 6% neither agree or disagree
- 40% Disagree ('strongly + somewhat') that the industry can deliver on future expectations
- 4% did not render an opinion or did not know

'Customer are confident in the electricity industry's ability to meet future expectations regarding quality, reliability and price' – do you agree?

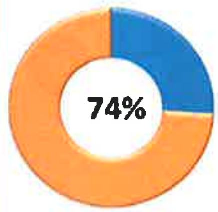
	NPEI	Ontario	UtilityPULSE Database
Top 2 Boxes: 'Strongly + Somewhat Agree'	49%	43%	49%

Base: total respondents / total respondents from the 2017 UtilityPULSE Database

24

Confidence in the industry

'Customers are confident in the electricity industry's ability to keep up with technological changes' – do you agree?



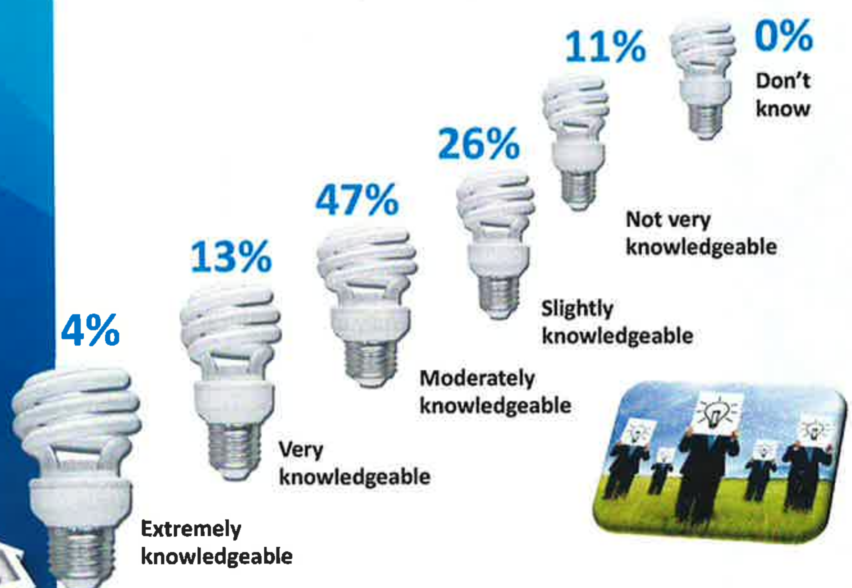
- 74% Agree ('strongly + somewhat') customers are confident that the electricity industry is able to keep up with technological changes
- 6% neither agree or disagree
- 14% Disagree ('strongly + somewhat') that the industry will keep up with changing technology
- 5% did not render an opinion or did not know

'Customer are confident in the electricity industry's ability to keep up with technological change' – do you agree?	NPEI	Ontario	UtilityPULSE Database
Top 2 Boxes: 'Strongly + Somewhat Agree'	74%	52%	64%

Base: total respondents / total respondents from the 2017 UtilityPULSE Database

25

Electric Utility Industry Knowledge



Base: total respondents

26

What portion of bill goes to LDC?

Approximate percentage of your hydro bill which goes to your LDC for all the services they provide to you

	NPEI
10%	4%
20%	6%
30%	8%
40%	7%
50% or Greater	14%
Don't know	60%
Refusal	1%

Base: total respondents

FOR NPEI IT IS APPROX. 20%

60%
"... did NOT know how to respond..."

27

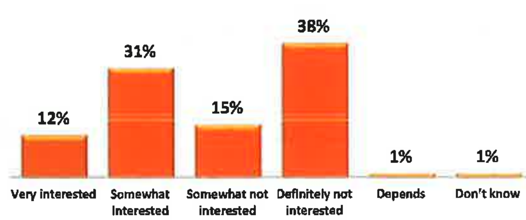
Purchasing an Electric Vehicle

Interest in Purchasing an Electric Vehicle

	NPEI
Very Interested	12%
Somewhat Interested	31%
Somewhat not Interested	15%
Definitely not Interested	38%
Depends	1%
Don't know	1%

Base: total respondents

Interest in purchasing a fully electric vehicle



are interested in purchasing a fully electric vehicle

Base: total respondents:
Top 2 Boxes: 'very + somewhat interested'

28

Purchasing an Electric Vehicle

Length of time before purchasing an electric vehicle	NPEI
Immediately to next 6 months	3%
7 to 12 months	5%
13 to 24 months	8%
Over 24 months	77%
Depends	2%
Don't know	3%

Base: total respondents who were interested

Length of time before purchasing an electric vehicle

77%

are considering the purchase of a fully electric vehicle over the next 24 months

Base: total respondents who were interested

29

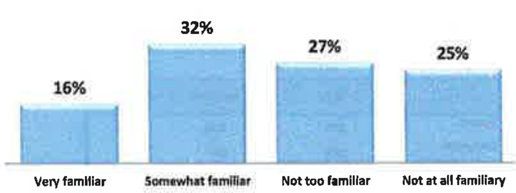
Energy Storage

Definition: *Energy storage is the capture of energy produced at one time for use at a later time.*

Familiarity with energy storage such as batteries and other equipment	NPEI
Very familiar	16%
Somewhat familiar	32%
Neither familiar or unfamiliar	0%
Not too familiar	27%
Not at all familiar	25%
Don't know	0%

Base: total respondents

Familiarity with Energy Storage technology



are familiar with energy storage such as batteries and other equipment

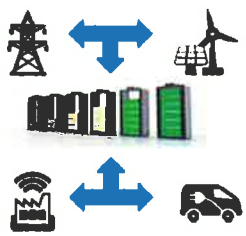
Base: total respondents:
Top 2 Boxes: Very + somewhat familiar

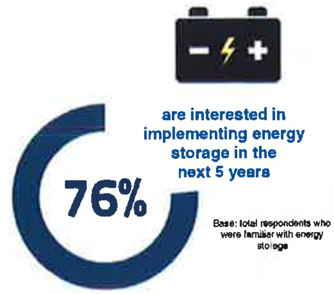
30

Energy Storage

Interest in implementing energy storage in the next 5 years	
	NPEI
Very interested	35%
Somewhat interested	41%
Neither interested or uninterested	0%
Somewhat not interested	9%
Definitely not interested	13%

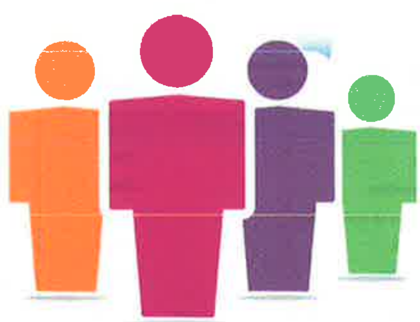
Base: total respondents who were familiar with energy storage





31

Customer Loyalty



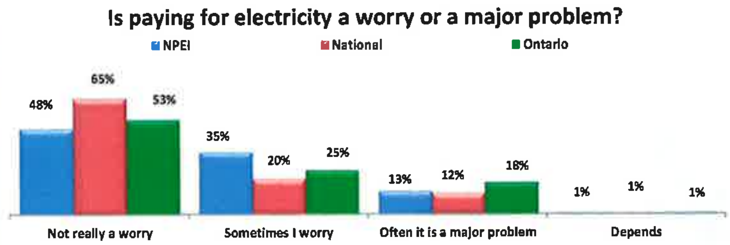
20% Secure | **15%** Favorable | **53%** Indifferent | **12%** At Risk

Loyalty Factor			
	NPEI	National	Ontario
Secure	20%	21%	14%
Favorable	15%	15%	12%
Indifferent	53%	51%	52%
At Risk	12%	14%	22%

Base: total respondents

33

Paying for electricity



Base: total respondents

Is paying for electricity a worry or a major problem?	kWh Group 1	kWh Group 2	kWh Group 3
Not really a worry	57%	50%	37%
Sometimes I worry	29%	35%	43%
Often it is a major problem	10%	13%	18%
Depends	2%	1%	1%

Base: total respondents

Group 1 represents 25% of the customer base derived from segmenting the customer data file into the first quartile of kWh usage.

Group 2 represents the middle 50% of the customer base; and

Group 3 represents the top quartile of kWh customers.

Group 1 uses the least amount of electricity on average, while Group 3 uses the most.

34

Hydro prices "a worry"

Is paying for electricity a worry or a major problem?	Not a worry	Sometimes	Often	Depends
2017	48%	35%	13%	1%
2016	-	-	-	-
2015	-	-	-	-
2014	57%	31%	6%	2%

Base: total respondents

- In 4 years, 'Not a worry' has dropped 9%; the Ontario benchmark shows a drop of 13% over the same timeframe; real concern is growing

"WORRY ABOUT HYDRO PRICES IS ON THE RISE"

- In 4 years, 'I **often** worry or I **sometimes** worry' has jumped from 37% to 48%

- The Ontario benchmark shows a jump from 32% to 43% of respondents over the same 4yr period

35

How can service be improved?

One or two most important things 'your local utility' could do to improve service	NPEI
Better prices/lower rates	56%
Improve/simplify/clarify billing	8%
Better communication with customers	5%
Improve money management	5%
Improve reliability of power	4%
Be more efficient	4%
Information & incentives on energy conservation	4%
Staff related concerns	4%
Eliminate solar/wind energy	3%
Eliminate SMART meters	2%
Delivery charges	2%
Restore power faster	1%

Base: total respondents

What Our Customers Say...

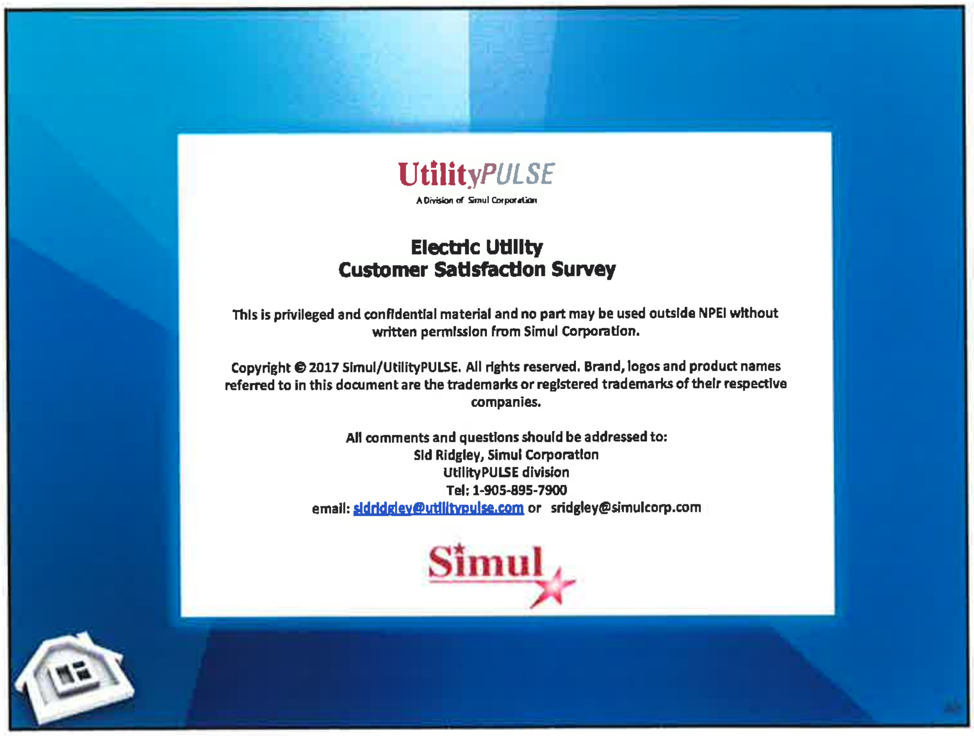
56%
"Better prices/lower rates..."

36

NUMBERS at a Glance

	NPEI 2017	National 2017	Ontario 2017
Customer Satisfaction: Initial	87%	89%	84%
Customer Satisfaction: Post	86%	86%	76%
Overall Satisfaction with most recent experience	70%	72%	63%
Customer Experience Performance Rating (CEPr)	83%	82%	80%
Customer Centric Engagement Index (CCEI)	81%	78%	74%
Credibility & Trust Index	82%	80%	77%
UtilityPulse Report Card©	A	B+	B

38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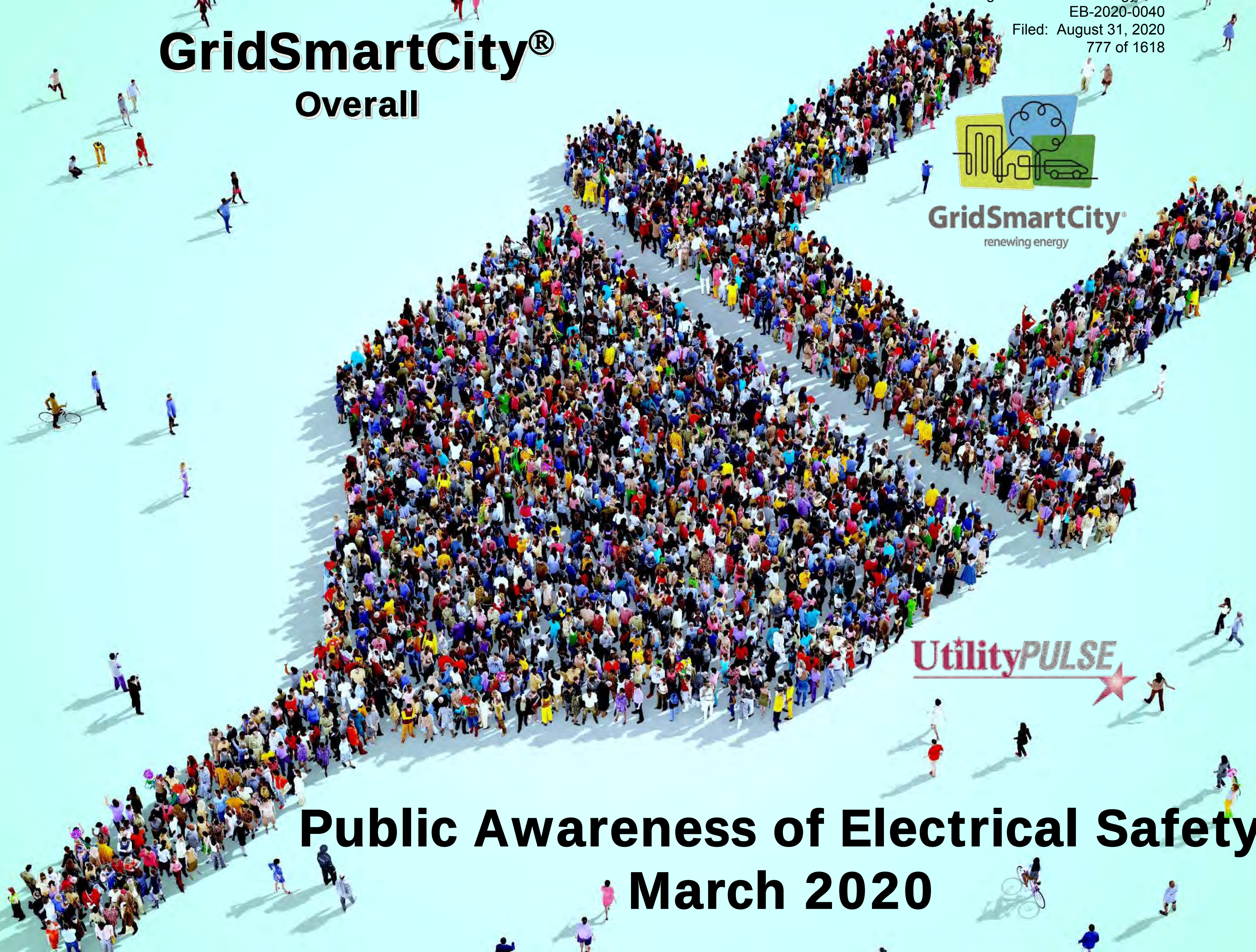
All comments and questions should be addressed to:
Sid Ridgley, Simul Corporation
UtilityPULSE division
Tel: 1-905-895-7900
email: sidridgley@utilitypulse.com or sridgley@simulcorp.com
Simul

Appendix 1-19

Public Awareness of Electrical Safety Survey Results 2020, 2018 and 2016

GridSmartCity®

Overall



GridSmartCity®
renewing energy

UtilityPULSE

Public Awareness of Electrical Safety
March 2020

UtilityPULSE
Public Awareness of Electrical Safety Report

This is privileged and confidential material and no part may be used other than the intended purpose of providing a score for the Ontario Energy Board Scorecard.

Results are based on a telephone survey (Random Digit Dialing) among 4799 Members of the General Public,18 years of age or older, residing within the 12 participating Grid Smart City's LDC Members' geographic service territories. The data has been statistically weighted according to Canadian census figures (2016) for age, gender and region.

Scores in this report follow Appendix A: Scorecard Methodology and Implementation Guide last published by the Ontario Energy Board November 25, 2015.

The questions used in the survey follow Appendix B: Biannual Standardized Scorecard Public Awareness of Electrical Safety Telephone Questionnaire last published by the Ontario Energy Board November 25, 2015.

All comments and questions should be addressed to:

UtilityPULSE
Tell: 905-895-7900 x 29
Project lead: Sid Ridgley
Email: sidridgley@utilitypulse.com
March, 2020

UtilityPULSE
Public Awareness of Electrical Safety Report
Executive Summary

Grid Smart City's Overall Public Safety Awareness Index Score is 82%. The UtilityPULSE cohort of participating LDCs Public Safety Awareness Score is 83%.

This is the third execution of the Public Awareness Electrical Safety survey; the first execution occurred in 2016. This survey compiles data to measure the level of awareness of key electrical safety precautions among the public within the electricity distributor's service territory. Results are based on a telephone survey (Random Digit Dialing) among 4799 Members of the General Public,18 years of age or older, within Grid Smart City's LDC Members' geographic service territories. The data has been statistically weighted according to Canadian census figures (2016) for age, gender and region.

The six core measurement questions correspond to the six most frequent incidents involving utility equipment in Ontario over the last decade. When looking at the distribution of responses for the six core measurement questions here are some of the key observations and recommendations going forward:

Question B5: Likelihood to *"call before you dig" [48% scored 1.00 pts]*
48% would 'definitely' and 21% were 'very likely' to call to locate electrical or other underground lines. While these figures indicate that many of your service territory's population would 'call before they dig', the remainder did not see this as a 'must do'. Even of those respondents who did reply they would definitely or very likely make the call, it is not clear if they would call because they were exerting due diligence for their property and household project OR if they were knowledgeable in the fact that this is the law that is in place.

Any education put forth on this core measurement must emphasize that **it is the law that one must 'call before you dig'.**

UtilityPULSE
Public Awareness of Electrical Safety Report
Executive Summary (continued)

Question B6: Impact of touching a power line *[94% scored 1.00 pts]*
94% knew that is ‘very dangerous’ and 4% believed it is ‘somewhat dangerous’ to touch an overhead power line with their body or any object.

Any education put forth on this core measurement must continue to emphasize & re-emphasize the perils associated with touching a power line. The key message that needs to continue to be driven to the public on this measurement is clear and simple: **It is very dangerous to touch an overhead power line with your body or any object.**

Question B7: Proximity to overhead power line *[23% scored 1.00 pts]*
This is one of two questions that contained a concept of measurement of distance from a power line constituting safe proximity. 23% indicated that they believed that there needed to be a distance of 3 metres to less than 6 metres and 54% indicated a distance of 6 metres or more to safely come close to an overhead power line with their body or an object. While this indicates there is knowledge that there needs to be a “certain” proximity maintained from an overhead power line, the exact measurement is not quite readily known. It is also indicative that while most people believed a “certain” distance was required, it is not clear how many chose the higher distance because of a prevailing thought that ‘the further away the safer you are’.

While being further away i.e. 6 metres or more is not technically incorrect, the point of this question is to educate the public that there is a reasonable distance that needs to be maintained. Any education put forth on this core measurement must clearly emphasize that a person can be as close as 3 metres to safely come close to an overhead power line while undertaking outdoor activities. This message whether in print or graphically depicted has to be clear and identifiable as not to confuse with the second question concerning distance from a ‘downed’ power line (QB9).

One key to improving awareness is to help the public at large to learn & **remember the required minimum distance is 3 metres to an <u>overhead</u> power line.**

UtilityPULSE
Public Awareness of Electrical Safety Report
Executive Summary (continued)

Question B8: Danger of tampering with electrical equipment *[89% scored 1.00 pts]*
89% knew that is ‘very dangerous’ to tamper with electrical equipment, while 8% believed it was ‘somewhat dangerous’.

Any education put forth on this core measurement must continue to emphasize & re-emphasize the perils associated with touching or tampering with electrical equipment. **Any electrical equipment is a no play zone for children and/or pets and in general all persons are not touch or tamper with the electrical equipment.**

Question B9: Proximity to downed power line *[77% scored 1.00 pts]*
This is the second question containing a concept of measurement of distance; in this instance it is safe proximity from a downed power line. 77% indicated that a distance of 10 metres or more needed to be maintained from a downed power line. As in QB7, while this indicates there is knowledge that there needs to be a “certain” proximity maintained from a downed power line, it is not clear how many chose the higher distance because of a prevailing thought that ‘the further away the safer you are’. In this instance however, choosing the furthest distance is the correct answer.

The point of this question is to educate the public that there is a reasonable distance that needs to be maintained from a downed power line and this distance is at least 10 metres. This message whether emphasized in print or graphically depicted has to be clear and identifiable as not to confuse with the question concerning distance of 3 metres from an ‘overhead’ power line (QB7).

One key to improving awareness is to help the public at large to learn & remember **the minimum distance from a <u>downed</u> power line is 10 metres.**

UtilityPULSE
Public Awareness of Electrical Safety Report
Executive Summary (continued)

Question B10: Actions taken in vehicle in contact with wires *[90% scored 1.00 pts]*
90% responded the safer action in this case would be to ‘stay in the vehicle until power was disconnected from the line’.

Any education put forth on this core measurement must continue to emphasize & re-emphasize the harm associated with stepping out of a vehicle that is in contact with a downed power line. While some people instinctually feel that getting out and seeking help would be the proper thing to do, **the public needs to be educated that should their vehicle come in contact with power lines, staying in the vehicle is their best and safest option until the power is disconnected.**

Additional Questions for Grid Smart City Clients:

Question GSC1: Primary source of electrical safety information
33% cited the primary source of their electrical safety information as their **local utility website**
30% cited **online searches**
17% cited the **ESA**
6% cited a **relative or friend**
1% cited **social media**
11% cited **other** and
2% **preferred not to say or simply did not know**.

It would seem overall the internet is the overwhelming source of electrical safety information whether it was from online searches or the utility’s website as 63% of all respondents listed one or the other. 37% of respondents cited all other sources combined.

UtilityPULSE
Public Awareness of Electrical Safety Report
Executive Summary (continued)

Additional Questions for Grid Smart City Clients:

Question GSC2: Probing for households with children aged 6 to 13

25% responded that their household was comprised of school aged children.

Question GSC3: Conversations with children about the dangers of powerlines and playing near electrical equipment

Over half, **51%** claimed they did have a conversation with their children discussing the dangers of powerlines and playing near electrical equipment. While it is encouraging that parents and families recognize the need to discuss electrical safety with their children, more has to be done to ensure that more parents and families are motivated to have this discussion to prevent potential injury and even fatalities.

Additional Research by UtilityPULSE:

Question C1: Importance of GFCI receptacles

78% responded that it is ‘very important’ and 14% said it is ‘somewhat important’ to have GFCI receptacles in the kitchen and bathroom.

Question C2: Danger of attempting repairs to the electrical panel

49% responded that it is ‘very dangerous’ and 36% said it is ‘somewhat dangerous’ to repair or change a circuit breaker in an electrical panel.

This additional research was conducted January – March 2020.

UtilityPULSE
Public Awareness of Electrical Safety Report
Executive Summary (continued)

Grid Smart City
Public Safety Awareness Index Score

This **index score** is calculated using the following formulas:

Step 1: Add each individual respondent's key measurement questions using the provided response values.

	B5
+	B6
+	B7
+	B8
+	B9
+	B10
=	**Individual respondent's cumulative score**

Step 2:
Individual respondent's cumulative score / # of sections
= Respondent Standardized Score

Step 3:
Summation of all **"Respondent Standardized Scores" /** n-size (i.e. total sample size)
= Raw Index Score

Step 4:
Raw Index Score × 100 = **Index Score** (bound between 0-100%)

Responses will be indexed to create a single comparable Public Safety Awareness Score

Public Safety Awareness Index Score

83%

Grid Smart City Group

Based on 12 participating LDCs

B5. Likelihood to *"call before you dig"*

If you were to undertake a household project that required digging – such as planting a tree or building a deck – how likely are you to call to locate electrical or other underground lines?

Response	Score	% of respondents
Definitely	1.00 pts	**48%**
Very likely	0.75 pts	**21%**
Somewhat likely	0.50 pts	**13%**
Not very likely	0.00 pts	**7%**
Not at all likely	0.00 pts	**7%**
I would not undertake a project that required digging	omitted[1]	**3%**
Don't know	0.00 pts	**1%**

	Grid Smart City	Overall
CORRECT ✓	82%	83%
INCORRECT ✗	18%	17%

Correct: Any response which scored above 0 pts
Incorrect: Any response which scored 0 pts including Don't know

1-800-400-2255

B5. Likelihood to *"call before you dig"*

If you were to undertake a household project that required digging – such as planting a tree or building a deck – how likely are you to call to locate electrical or other underground lines?

Response	Gender Male	Gender Female	Age 18-24	Age 25-34	Age 35-44	Age 45-54	Age 55-64	Age 65+
Definitely	46%	50%	27%	41%	49%	56%	55%	53%
Very likely	22%	20%	18%	21%	26%	19%	22%	21%
Somewhat likely	14%	12%	26%	15%	13%	10%	9%	6%
Not very likely	7%	6%	12%	10%	5%	6%	4%	5%
Not at all likely	8%	6%	15%	6%	6%	5%	6%	7%
I would not undertake a project that required digging[1]	2%	4%	1%	3%	2%	2%	3%	6%
Don't know	1%	2%	0%	3%	0%	1%	1%	2%

1-800-400-2255

Percentage may not add up to 100% due to rounding

B6. Impact of touching a power line

How dangerous do you believe it is to touch – with your body or any object – an overhead power line?

Response	Score	% of respondents
Very dangerous	1.00 pts	**94%**
Somewhat dangerous	0.50 pts	**4%**
Not very dangerous	0.00 pts	**0%**
Not at all dangerous	0.00 pts	**1%**
Don't know	0.00 pts	**0%**

	Grid Smart City	Overall
CORRECT ✓		98%
INCORRECT ✗		2%

Correct: Any response which scored above 0 pts
Incorrect: Any response which scored 0 pts including Don't know

Percentage may not add up to 100% due to rounding

B6. Impact of touching a power line

How dangerous do you believe it is to touch – with your body or any object – an overhead power line?

Response	Gender Male	Gender Female	Age 18-24	Age 25-34	Age 35-44	Age 45-54	Age 55-64	Age 65+
Very dangerous	94%	95%	89%	97%	93%	97%	95%	93%
Somewhat dangerous	5%	4%	10%	3%	6%	3%	3%	3%
Not very dangerous	1%	0%	0%	0%	0%	0%	1%	1%
Not at all dangerous	1%	0%	1%	0%	1%	0%	1%	1%
Don't know	0%	0%	0%	0%	0%	0%	1%	1%

B7. Proximity to overhead power line

When undertaking outdoor activities – such as, standing on a ladder, cleaning windows or eaves, climbing or trimming trees – how close do you believe you can safely come to an overhead power line with your body or an object? Would you say …

Response	Score	% of respondents
You can safely touch an overhead power line	0.00 pts	0%
Less than 1 metre (i.e. less than 3 feet)	0.00 pts	4%
1 to less than 3 metres (i.e. 3 to less than 10 feet)	0.00 pts	14%
3 metres to less than 6 metres (i.e. 10 feet to less than 20 feet)	1.00 pts	23%
You should maintain a distance of 6 metres or more (i.e. 20 feet or more)	0.75 pts	54%
Don't know	0.00 pts	4%

	Grid Smart City	Overall
CORRECT ✓		77%
INCORRECT ✗		23%

Correct: Any response which scored above 0 pts
Incorrect: Any response which scored 0 pts including Don't know

Percentage may not add up to 100% due to rounding

B7. Proximity to overhead power line

When undertaking outdoor activities – such as, standing on a ladder, cleaning windows or eaves, climbing or trimming trees – how close do you believe you can safely come to an overhead power line with your body or an object? Would you say …

Response	Gender Male	Gender Female	Age 18-24	Age 25-34	Age 35-44	Age 45-54	Age 55-64	Age 65+
You can safely touch an overhead power line	0%	1%	0%	0%	1%	0%	1%	1%
Less than 1 metre (i.e. less than 3 feet)	3%	5%	8%	4%	4%	3%	4%	3%
1 to less than 3 metres (i.e. 3 to less than 10 feet)	14%	14%	17%	14%	18%	15%	13%	10%
3 metres to less than 6 metres (i.e. 10 feet to less than 20 feet)	26%	21%	28%	26%	24%	25%	20%	18%
You should maintain a distance of 6 metres or more (i.e. 20 feet or more)	54%	54%	47%	54%	51%	53%	57%	58%
Don't know	2%	6%	1%	2%	3%	3%	5%	10%

B8. Danger of tampering with electrical equipment

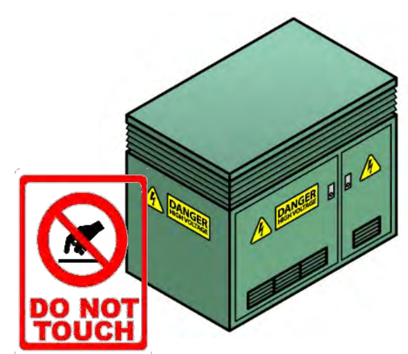
Some electrical utility equipment is located on the ground, such as locked steel cabinets that contain transformers.

How dangerous do you believe it is to try to open, remove contents, or touch the equipment inside? Would you say …

Response	Score	% of respondents
Very dangerous	1.00 pts	**89%**
Somewhat dangerous	0.50 pts	**8%**
Not very dangerous	0.00 pts	**2%**
Not dangerous at all	0.00 pts	**0%**
Don't know	0.00 pts	**0%**

	Grid Smart City	Overall
CORRECT ✓		98%
INCORRECT ✗		2%

Correct: Any response which scored above 0 pts
Incorrect: Any response which scored 0 pts including Don't know



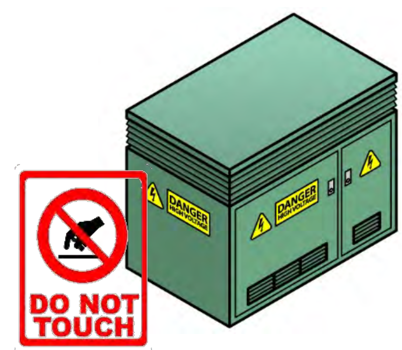
Percentage may not add up to 100% due to rounding

B8. Danger of tampering with electrical equipment

Some electrical utility equipment is located on the ground, such as locked steel cabinets that contain transformers.

How dangerous do you believe it is to try to open, remove contents, or touch the equipment inside? Would you say …

Response	Gender Male	Gender Female	Age 18-24	Age 25-34	Age 35-44	Age 45-54	Age 55-64	Age 65+
Very dangerous	90%	88%	86%	88%	89%	91%	91%	91%
Somewhat dangerous	7%	9%	9%	11%	9%	8%	7%	6%
Not very dangerous	2%	2%	5%	2%	1%	1%	1%	1%
Not dangerous at all	1%	0%	0%	0%	1%	0%	1%	1%
Don't know	0%	0%	0%	0%	0%	0%	0%	1%

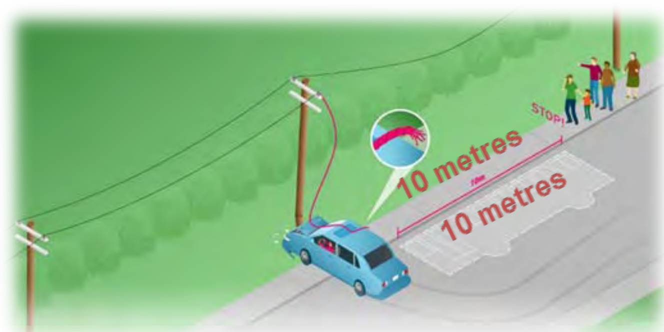


B9. Proximity to downed power line

How close do you believe you can safely come to a downed overhead power line, such as a downed line caused by a storm or accident? Would you say …

Response	Score	% of respondents
You can safely touch a downed overhead power line	0.00 pts	**0%**
Less than 1 metre (i.e. less than 3 feet)	0.00 pts	**1%**
1 to less than 5 metres (i.e. 3 to less than 16 feet)	0.00 pts	**6%**
5 metres to less than 10 metres (i.e. 16 feet to less than 33 feet)	0.00 pts	**14%**
You should maintain a distance of 10 metres or more (i.e. 33 feet or more)	1.00 pts	**77%**
Don't know	0.00 pts	**1%**

	Grid Smart City	Overall
CORRECT ✓		79%
INCORRECT ✗		21%



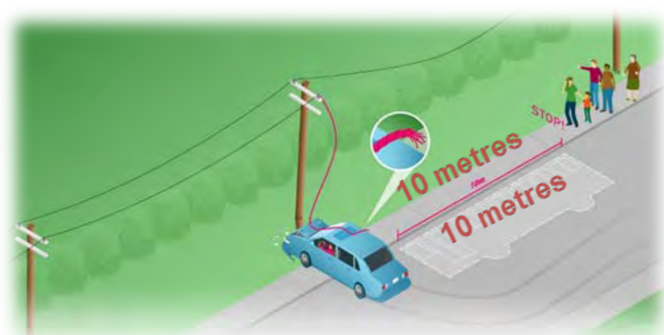
Correct: Any response which scored above 0 pts
Incorrect: Any response which scored 0 pts including Don't know

Percentage may not add up to 100% due to rounding

B9. Proximity to downed power line

How close do you believe you can safely come to a downed overhead power line, such as a downed line caused by a storm or accident? Would you say …

Response	Gender Male	Gender Female	Age 18-24	Age 25-34	Age 35-44	Age 45-54	Age 55-64	Age 65+
You can safely touch a downed overhead power line	0%	0%	0%	0%	0%	0%	0%	0%
Less than 1 metre (i.e. less than 3 feet)	1%	1%	0%	0%	1%	1%	2%	1%
1 to less than 5 metres (i.e. 3 to less than 16 feet)	7%	5%	9%	9%	4%	4%	5%	5%
5 metres to less than 10 metres (i.e. 16 feet to less than 33 feet)	12%	17%	25%	10%	14%	16%	12%	12%
You should maintain a distance of 10 metres or more (i.e. 33 feet or more)	80%	75%	66%	81%	80%	78%	79%	77%
Don't know	1%	2%	0%	0%	0%	1%	2%	4%

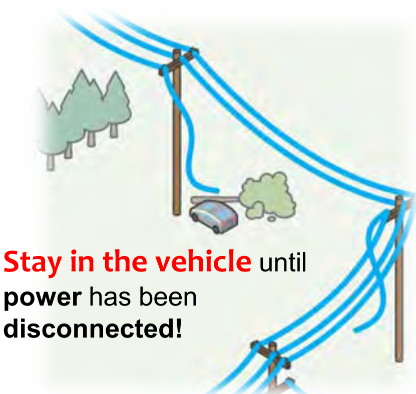


B10. Actions taken in vehicle in contact with wires

If you were in a vehicle – such as a car, bus, or truck – and an overhead power line came down on top of it, which of the following options do you believe is generally safer?

Response	Score	% of respondents
Get out quickly and seek help	0.00 pts	**9%**
Stay in the vehicle until power has been disconnected from the line	1.00 pts	**90%**
Don't know	0.00 pts	**1%**

	Grid Smart City	Overall
CORRECT ✓		90%
INCORRECT ✗		10%



Stay in the vehicle until **power** has been **disconnected!**

Correct: Any response which scored above 0 pts
Incorrect: Any response which scored 0 pts including Don't know

Percentage may not add up to 100% due to rounding

B10. Actions taken in vehicle in contact with wires

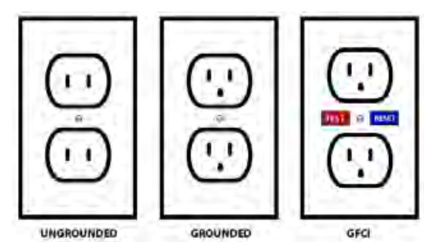
If you were in a vehicle – such as a car, bus, or truck – and an overhead power line came down on top of it, which of the following options do you believe is generally safer?

Response	Gender Male	Gender Female	Age 18-24	Age 25-34	Age 35-44	Age 45-54	Age 55-64	Age 65+
Get out quickly and seek help	9%	10%	14%	13%	9%	8%	6%	7%
Stay in the vehicle until power has been disconnected from the line	91%	89%	86%	87%	89%	90%	94%	91%
Don't know	1%	1%	1%	0%	2%	2%	1%	2%

C1. Importance of GFCI receptacles

Response	% of respondents	Outdoor Trades	Electricians
Very important	78%	96%	96%
Somewhat important	14%	4%	4%
Not very important	1%	0%	0%
Not at all important	1%	0%	0%
Don’t know	6%	0%	0%

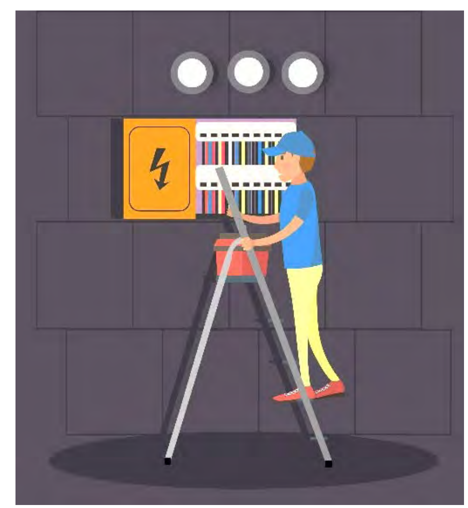
Additional research for UtilityPULSE clients



C2. Danger of tampering with electrical panel

Response	% of respondents
Very dangerous	49%
Somewhat dangerous	36%
Not very dangerous	5%
Not at all dangerous	3%
Don't know	7%

Additional research for UtilityPULSE clients



Grid Smart City

GSC1. Could you tell me what would be your primary source for finding information about electricity safety?

Response	Overall	Gender Male	Gender Female	Age 18-24	Age 25-34	Age 35-44	Age 45-54	Age 55-64	Age 65+
Local utility website	33%	31%	35%	23%	25%	30%	39%	39%	39%
Electrical Safety Authority	17%	21%	14%	11%	22%	17%	18%	17%	17%
Online search	30%	31%	30%	45%	37%	35%	29%	24%	16%
Social media	1%	1%	1%	1%	0%	0%	0%	1%	1%
Relative or friend	6%	4%	8%	9%	4%	7%	5%	5%	6%
Other	11%	11%	11%	10%	9%	9%	8%	11%	18%
Don’t Know, Refused, Prefer not to say	2%	2%	2%	1%	2%	1%	1%	1%	4%

[1]*Note: Unweighted data*

Grid Smart City

GSC2. Do you have any children, living with you, who are 6 to 13 years old?

Response	% of respondents
Yes	25%
No	74%
Did not answer	0%

[1]*Note: Unweighted data*

GSC3. Have you had a conversation within the last year with your child or children about the dangers of powerlines and playing near electrical equipment?

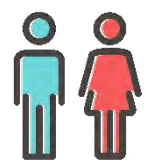
Response	% of respondents
Yes	51%
No	48%
Did not answer	1%

Percentage may not add up to 100% due to rounding

Grid Smart City
Public Awareness of Electrical Safety Report
Demographics

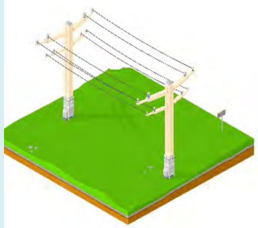
Response	% of respondents Based on Census data
18 to 24	12%
25 to 34	17%
35 to 44	17%
45 to 54	19%
55 to 64	16%
65 or older	19%

Response	% of respondents Based on Census data
Male	48%
Female	52%



Percentage may not add up to 100% due to rounding

Grid Smart City
Public Awareness of Electrical Safety Report
Demographics



Response	% of respondents
Yes	7%
No	92%
Don’t know	0%

Proceed to the following question only If Respondent answers ‘Yes’ …

Response	% of respondents
Transportation	9%
General labour	12%
Construction or outdoor trades	30%
Electrician	15%
Other	30%
Don’t know/Prefer not to say	4%

Percentage may not add up to 100% due to rounding

Grid Smart City
Public Awareness of Electrical Safety Report
Demographics

Response	% of respondents
A fully-detached home	67%
A semi-detached home	6%
A townhome or row house	11%
An apartment or condo building less than 5 storeys	6%
An apartment or condo building 5 storeys or higher	5%
A farm	3%
Other	2%

Response	% of respondents
Overhead wires	39%
Underground cables	54%
Don’t know	7%

Percentage may not add up to 100% due to rounding

UtilityPULSE, through polls and surveys, provides executives and managers with feedback that assists in making both strategic and operational decisions. You know lots of companies that can gather data and provide a report. We believe that by specializing in the utility sector with our polls and surveys, you get stronger analysis of data and answers to key questions that help you formulate key strategies to assist your leaders in creating a better place to work and a better place to do business with.

UtilityPULSE is uniquely positioned to help your utility get feedback from Customers, through its Annual Electric Utility Customer Satisfaction Survey or customized research designed for you. In addition, we understand what it takes to create an organization where employees are engaged and enthusiastic about customers and the work that they do. Knowing what is going on with your customers and employees is one thing, doing something about it is another. We get paid for, and earn our clients' loyalty by, delivering objective insights with actionable recommendations; accomplished when every step of the process is completed with professionalism and pride. Our mission is to help you and your leadership team move from knowing to doing while improving performance and creating value to your customers, employees, stakeholders and the public at large.

Your personal contact is:
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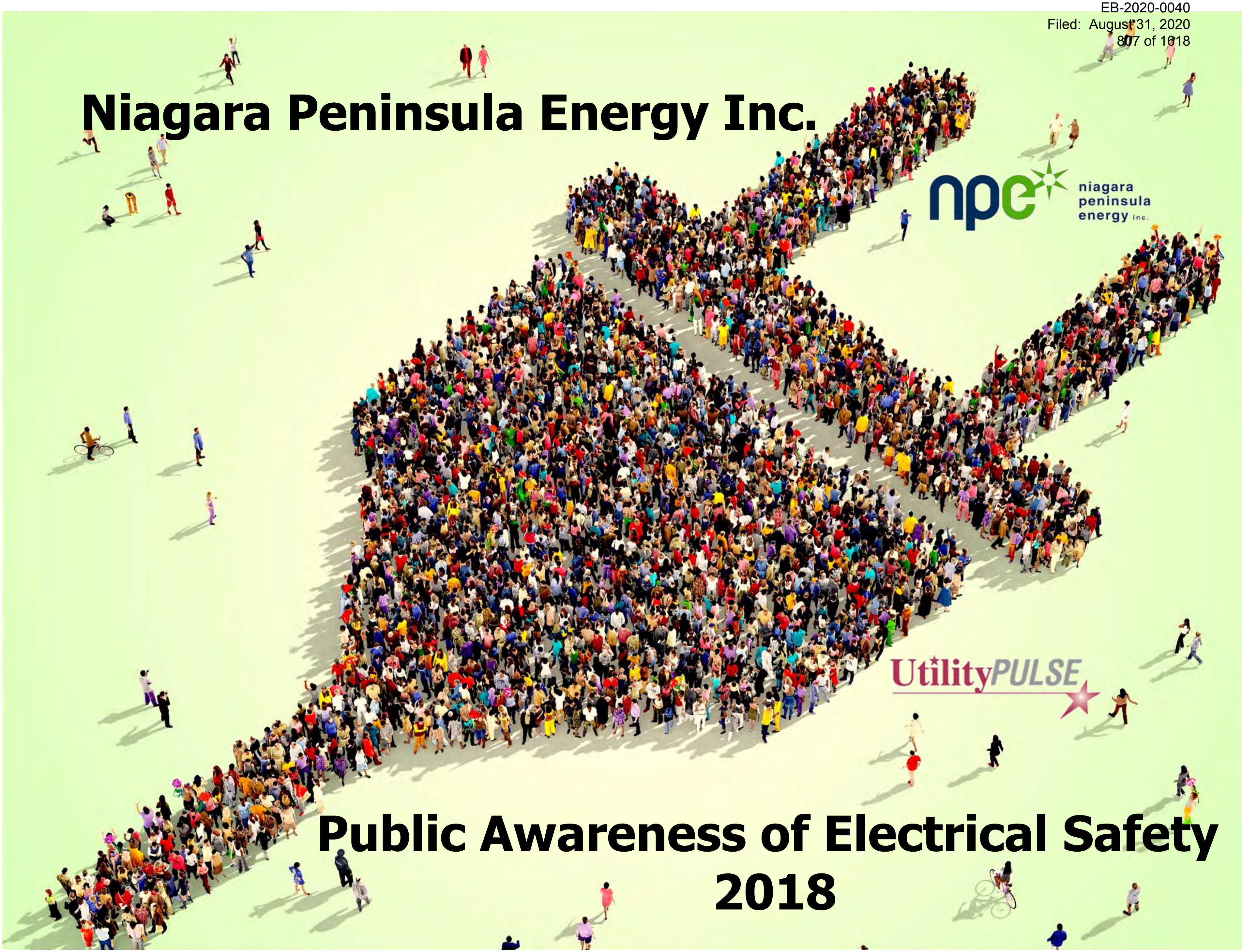
www.utilitypulse.com

UtilityPULSE



Niagara Peninsula Energy Inc.

Public Awareness of Electrical Safety 2018

UtilityPULSE
Public Awareness of Electrical Safety Report

This is privileged and confidential material and no part may be used other than the intended purpose of providing a score for the Ontario Energy Board Scorecard.

Results are based on a telephone survey (Random Digit Dialing) among 400 Members of the General Public,18 years of age or older, residing within the LDC's geographic service territory. The data has been statistically weighted according to Canadian census figures (2016) for age, gender and region.

Scores in this report follow Appendix A: Scorecard Methodology and Implementation Guide published by the Ontario Energy Board November 25, 2015.

The questions used in the survey follow Appendix B: Biannual Standardized Scorecard Public Awareness of Electrical Safety Telephone Questionnaire published by the Ontario Energy Board November 25, 2015.

All comments and questions should be addressed to:

UtilityPULSE
Toll free: 1-888-291-7892 or Local: 905-895-7900
Project lead: Sid Ridgley
Email: sidridgley@utilitypulse.com

UtilityPULSE

UtilityPULSE
Public Awareness of Electrical Safety Report
Executive Summary

Niagara Peninsula Energy's Public Safety Awareness Index Score is 83%.

This is the second execution of the Public Awareness Electrical Safety survey; the first execution occurred in 2016. This survey compiles data to measure the level of awareness of key electrical safety precautions among the public within the electricity distributor's service territory. Results are based on a telephone survey (Random Digit Dialing) among 400 Members of the General Public,18 years of age or older, within the LDC's geographic service territory. The data has been statistically weighted according to Canadian census figures (2016) for age, gender and region.

The six core measurement questions correspond to the six most frequent incidents involving utility equipment in Ontario over the last decade. When looking at the distribution of responses for the six core measurement questions here are some of the key observations and recommendations going forward:

Question B5: Likelihood to *"call before you dig" [62.2% scored 1.00 pts]*
62.2% would 'definitely' and 17.5% were 'very likely' to call to locate electrical or other underground lines. While these figures indicate that many of your service territory's population would 'call before they dig', the remainder did not see this as a 'must do'. Even of those respondents who did reply they would definitely or very likely make the call, it is not clear if they would call because they were exerting due diligence for their property and household project OR if they were knowledgeable in the fact that this is the law that is in place.

Any education put forth on this core measurement must emphasize that **it is the law that one must 'call before you dig'.**

UtilityPULSE
Public Awareness of Electrical Safety Report
Executive Summary (continued)

Question B6: Impact of touching a power line *[92.6% scored 1.00 pts]*
92.6% knew that is 'very dangerous' and 4.2% believed it is 'somewhat dangerous' to touch an overhead power line with their body or any object.

Any education put forth on this core measurement must continue to emphasize & re-emphasize the perils associated with touching a power line. The key message that needs to continue to be driven to the public on this measurement is clear and simple: **It is very dangerous to touch an overhead power line with your body or any object.**

Question B7: Proximity to overhead power line *[18.6% scored 1.00 pts]*
This is one of two questions that contained a concept of measurement of distance from a power line constituting safe proximity. 18.6% indicated that they believed that there needed to be a distance of 3 metres to less than 6 metres and 61.4% indicated a distance of 6 metres or more to safely come close to an overhead power line with their body or an object. While this indicates there is knowledge that there needs to be a "certain" proximity maintained from an overhead power line, the exact measurement is not quite readily known. It is also indicative that while most people believed a "certain" distance was required, it is not clear how many chose the higher distance because of a prevailing thought that 'the further away the safer you are'.

While being further away i.e. 6 metres or more is not technically incorrect, the point of this question is to educate the public that there is a reasonable distance that needs to be maintained. Any education put forth on this core measurement must clearly emphasize that a person can be as close as 3 metres to safely come close to an overhead power line while undertaking outdoor activities. This message whether in print or graphically depicted has to be clear and identifiable as not to confuse with the second question concerning distance from a 'downed' power line (QB9).

One key to improving awareness is to help the public at large to learn & **remember the required minimum distance is 3 metres to an <u>overhead</u> power line.**

UtilityPULSE
Public Awareness of Electrical Safety Report
Executive Summary (continued)

Question B8: Danger of tampering with electrical equipment *[86.7% scored 1.00 pts]*
86.7% knew that is 'very dangerous' to tamper with electrical equipment, while 8.3% believed it was 'somewhat dangerous'.

Any education put forth on this core measurement must continue to emphasize & re-emphasize the perils associated with touching or tampering with electrical equipment. **Any electrical equipment is a no play zone for children and/or pets and in general all persons are not touch or tamper with the electrical equipment.**

Question B9: Proximity to downed power line *[81.3% scored 1.00 pts]*
This is the second question containing a concept of measurement of distance; in this instance it is safe proximity from a downed power line. 81.3% indicated that a distance of 10 metres or more needed to be maintained from a downed power line. As in QB7, while this indicates there is knowledge that there needs to be a "certain" proximity maintained from a downed power line, it is not clear how many chose the higher distance because of a prevailing thought that 'the further away the safer you are'. In this instance however, choosing the furthest distance is the correct answer.

The point of this question is to educate the public that there is a reasonable distance that needs to be maintained from a downed power line and this distance is at least 10 metres. This message whether emphasized in print or graphically depicted has to be clear and identifiable as not to confuse with the question concerning distance of 3 metres from an 'overhead' power line (QB7).

One key to improving awareness is to help the public at large to learn & remember **the minimum distance from a <u>downed</u> power line is 10 metres.**

UtilityPULSE
Public Awareness of Electrical Safety Report
Executive Summary (continued)

Question B10: Actions taken in vehicle in contact with wires *[86.9% scored 1.00 pts]*
86.9% responded the safer action in this case would be to 'stay in the vehicle until power was disconnected from the line'.

Any education put forth on this core measurement must continue to emphasize & re-emphasize the harm associated with stepping out of a vehicle that is in contact with a downed power line. While some people instinctually feel that getting out and seeking help would be the proper thing to do, **the public needs to be educated that should their vehicle come in contact with power lines, staying in the vehicle is their best and safest option until the power is disconnected.**

Additional Questions for Grid Smart City Clients:

Question GSC1: Primary source of electrical safety information

33.1% cited the primary source of their electrical safety information came from the **local utility website**
29.9% cited **online searches**
16.4% cited the **ESA**
9.5% cited **other**
8.3% cited a **relative or friend**
1.2% cited **social media** and
1.6% **preferred not to say or simply did not know**.

It would seem overall the internet is the overwhelming source of electrical safety information whether it was from online searches or the utility's website as 63.0% of all respondents listed one or the other. 35.4% of respondents cited all other sources combined.

UtilityPULSE
Public Awareness of Electrical Safety Report
Executive Summary (continued)

Additional Questions for Grid Smart City Clients:

Question GSC2: Probing for households with children aged 6 to 13

20.2% responded that their household was comprised of school aged children.

Question GSC3: Conversations with children about the dangers of powerlines and playing near electrical equipment

57.1% claimed they did have a conversation with their children discussing the dangers of powerlines and playing near electrical equipment. While it is encouraging that parents and families recognize the need to discuss electrical safety with their children, more has to be done to ensure that more parents and families are motivated to have this discussion to prevent potential injury and even fatalities.

Conclusion:

Both the 2016 survey and this survey of the public in your service territory about electrical safety show many respondents do have good knowledge or have received some information pertaining to the 6 core measurement questions. Niagara Peninsula Energy's Public Safety Awareness Index Score is 83%.

The OEB has indicated that the performance target for public awareness of electrical safety will be established once three years of data is gathered; two years of data of have been gathered as of this time. In the meantime, your LDC will be expected to demonstrate the impact of your public education efforts through biannual surveying of adults residing in your service territory.

As you continue to develop safety awareness campaigns, we recommend that you look through this report along with your data report to see where, among the population, awareness levels are lower and where outreach can be targeted. Focus on the messages which are simple and memorable which help the public ***learn and remember***. We also recommend that you share your results with your employees, especially those who may be in contact with outside workers, as they too can help spread the safety message.

Sid Ridgley

UtilityPULSE

Niagara Peninsula Energy
Public Safety Awareness Index Score

This **index score** is calculated using the following formulas:

Step 1: Add each individual respondent's key measurement questions using the provided response values.

	B5
+	B6
+	B7
+	B8
+	B9
+	B10
=	**Individual respondent's cumulative score**

Step 2:
Individual respondent's cumulative score / # of sections
= Respondent Standardized Score

Step 3:
Summation of all **"Respondent Standardized Scores" /** n-size (i.e. total sample size)
= Raw Index Score

Step 4:
Raw Index Score × 100 = **Index Score** (bound between 0-100%)

Responses will be indexed to create a single comparable Public Safety Awareness Score

In some cases, a respondent will have no intention of undertaking a project that requires digging. In this case, the index is based on only the 5 relevant sections of scorecard. This question (B5) will be removed from the calculation.

NPEI

Public Safety Awareness Index Score

83%

B5. Likelihood to *"call before you dig"*

If you were to undertake a household project that required digging – such as planting a tree or building a deck – how likely are you to call to locate electrical or other underground lines?

Response	Score	% of respondents
Definitely	1.00 pts	**62.2%**
Very likely	0.75 pts	**17.5%**
Somewhat likely	0.50 pts	**4.8%**
Not very likely	0.00 pts	**3.2%**
Not at all likely	0.00 pts	**10.4%**
I would not undertake a project that required digging	omitted[1]	**1.7%**
Don't know	0.00 pts	**0.1%**

[1]Note: In some cases, a respondent will have no intention of undertaking a project that requires digging. In this case, the index is based on only the five relevant sections of the scorecard. This question will be removed from the calculation of the Individual Respondent's cumulative score.

CORRECT ✓ 84.5%

INCORRECT ✗ 15.5%

Correct: Any response which scored above 0 pts
Incorrect: Any response which scored 0 pts including Don't know

ONTARIO ONECALL

*Planting a tree, building a deck or a fence? Contact **ON1Call** first to get a locate so you can dig safely.*

1-800-400-2255

B5. Likelihood to *"call before you dig"*

If you were to undertake a household project that required digging – such as planting a tree or building a deck – how likely are you to call to locate electrical or other underground lines?

Response	Gender Male	Gender Female	Age 18-24	Age 25-34	Age 35-44	Age 45-54	Age 55-64	Age 65+
Definitely	66.4%	58.4%	75.4%	50.0%	69.1%	57.7%	67.5%	58.5%
Very likely	15.8%	19.1%	24.6%	0.0%	21.9%	25.0%	18.2%	15.8%
Somewhat likely	3.8%	5.7%	0.0%	0.0%	6.1%	11.6%	4.5%	3.9%
Not very likely	2.0%	4.4%	0.0%	0.0%	3.0%	3.6%	5.3%	5.5%
Not at all likely	11.0%	9.8%	0.0%	50.0%	0.0%	2.0%	2.8%	8.6%
I would not undertake a project that required digging[1]	1.0%	2.3%	0.0%	0.0%	0.0%	0.0%	1.7%	7.1%
Don't know	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%

[1]Note: In some cases, a respondent will have no intention of undertaking a project that requires digging. In this case, the index is based on only the five relevant sections of the scorecard. This question will be removed from the calculation of the Individual Respondent's cumulative score.

ONTARIO ONECALL

*Planting a tree, building a deck or a fence? Contact **ON1Call** first to get a locate so you can dig safely.*

1-800-400-2255

B6. Impact of touching a power line

How dangerous do you believe it is to touch – with your body or any object – an overhead power line?

Response	Score	% of respondents
Very dangerous	1.00 pts	**92.6%**
Somewhat dangerous	0.50 pts	**4.2%**
Not very dangerous	0.00 pts	**2.6%**
Not at all dangerous	0.00 pts	**0.5%**
Don't know	0.00 pts	**0.2%**

CORRECT ✓ **96.8%**

INCORRECT ✗ **3.2%**

Correct: Any response which scored above 0 pts
Incorrect: Any response which scored 0 pts including Don't know

Percentage may not add up to 100% due to rounding

B6. Impact of touching a power line

How dangerous do you believe it is to touch – with your body or any object – an overhead power line?

Response	Gender Male	Gender Female	Age 18-24	Age 25-34	Age 35-44	Age 45-54	Age 55-64	Age 65+
Very dangerous	93.1%	92.1%	75.4%	87.8%	97.4%	98.0%	97.3%	92.7%
Somewhat dangerous	1.5%	6.6%	24.6%	0.0%	2.6%	0.0%	1.8%	3.5%
Not very dangerous	4.9%	0.5%	0.0%	12.2%	0.0%	2.0%	0.8%	0.7%
Not at all dangerous	0.2%	0.8%	0.0%	0.0%	0.0%	0.0%	0.0%	2.4%
Don’t know	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%

Percentage may not add up to 100% due to rounding

B7. Proximity to overhead power line

When undertaking outdoor activities – such as, standing on a ladder, cleaning windows or eaves, climbing or trimming trees – how close do you believe you can safely come to an overhead power line with your body or an object? Would you say …

Response	Score	% of respondents
You can safely touch an overhead power line	0.00 pts	**2.0%**
Less than 1 metre (i.e. less than 3 feet)	0.00 pts	**1.9%**
1 to less than 3 metres (i.e. 3 to less than 10 feet)	0.00 pts	**13.8%**
3 metres to less than 6 metres (i.e. 10 feet to less than 20 feet)	1.00 pts	**18.6%**
You should maintain a distance of 6 metres or more (i.e. 20 feet or more)	0.75 pts	**61.4%**
Don't know	0.00 pts	**2.3%**

CORRECT ✓ 80.0%

INCORRECT ✗ 20.0%

Correct: Any response which scored above 0 pts
Incorrect: Any response which scored 0 pts including Don't know

Percentage may not add up to 100% due to rounding

B7. Proximity to overhead power line

When undertaking outdoor activities – such as, standing on a ladder, cleaning windows or eaves, climbing or trimming trees – how close do you believe you can safely come to an overhead power line with your body or an object? Would you say …

Response	Gender Male	Gender Female	Age 18-24	Age 25-34	Age 35-44	Age 45-54	Age 55-64	Age 65+
You can safely touch an overhead power line	4.0%	0.3%	0.0%	12.2%	0.0%	0.0%	0.0%	0.7%
Less than 1 metre (i.e. less than 3 feet)	3.2%	0.8%	0.0%	0.0%	0.0%	4.1%	2.0%	3.6%
1 to less than 3 metres (i.e. 3 to less than 10 feet)	21.5%	6.9%	0.0%	24.5%	19.3%	17.7%	11.2%	7.6%
3 metres to less than 6 metres (i.e. 10 feet to less than 20 feet)	29.5%	8.7%	33.9%	12.2%	16.3%	15.9%	21.3%	16.9%
You should maintain a distance of 6 metres or more (i.e. 20 feet or more)	40.6%	80.2%	66.1%	51.1%	64.4%	62.3%	61.3%	63.7%
Don't know	1.2%	3.2%	0.0%	0.0%	0.0%	0.0%	4.2%	7.5%

Percentage may not add up to 100% due to rounding

B8. Danger of tampering with electrical equipment

Some electrical utility equipment is located on the ground, such as locked steel cabinets that contain transformers.

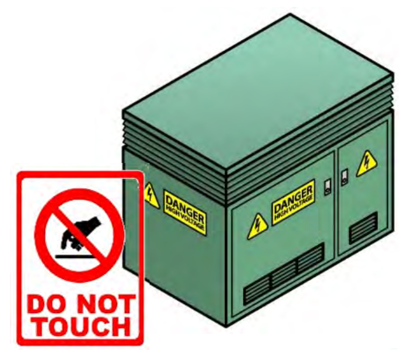
How dangerous do you believe it is to try to open, remove contents, or touch the equipment inside? Would you say …

Response	Score	% of respondents
Very dangerous	1.00 pts	**86.7%**
Somewhat dangerous	0.50 pts	**8.3%**
Not very dangerous	0.00 pts	**4.4%**
Not dangerous at all	0.00 pts	**0.6%**
Don’t know	0.00 pts	**0.0%**

CORRECT ✓ 95.0%

INCORRECT ✗ 5.0%

Correct: Any response which scored above 0 pts
Incorrect: Any response which scored 0 pts including Don’t know



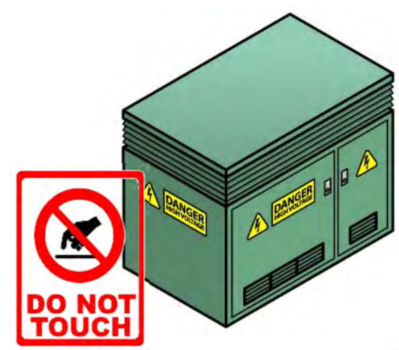
Percentage may not add up to 100% due to rounding

B8. Danger of tampering with electrical equipment

Some electrical utility equipment is located on the ground, such as locked steel cabinets that contain transformers.

How dangerous do you believe it is to try to open, remove contents, or touch the equipment inside? Would you say …

Response	Gender Male	Gender Female	Age 18-24	Age 25-34	Age 35-44	Age 45-54	Age 55-64	Age 65+
Very dangerous	94.2%	80.0%	75.4%	74.5%	86.3%	92.5%	94.7%	89.9%
Somewhat dangerous	4.3%	12.0%	24.6%	0.0%	13.7%	5.5%	3.5%	8.6%
Not very dangerous	0.5%	7.8%	0.0%	25.5%	0.0%	0.0%	1.8%	0.4%
Not dangerous at all	1.0%	0.3%	0.0%	0.0%	0.0%	2.0%	0.0%	1.1%
Don’t know	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%



Percentage may not add up to 100% due to rounding

B9. Proximity to downed power line

How close do you believe you can safely come to a downed overhead power line, such as a downed line caused by a storm or accident? Would you say …

Response	Score	% of respondents
You can safely touch a downed overhead power line	0.00 pts	**0.4%**
Less than 1 metre (i.e. less than 3 feet)	0.00 pts	**0.1%**
1 to less than 5 metres (i.e. 3 to less than 16 feet)	0.00 pts	**3.1%**
5 metres to less than 10 metres (i.e. 16 feet to less than 33 feet)	0.00 pts	**14.0%**
You should maintain a distance of 10 metres or more (i.e. 33 feet or more)	1.00 pts	**81.3%**
Don’t know	0.00 pts	**1.1%**

CORRECT ✓ **81.3%**

INCORRECT ✗ **18.7%**

Correct: Any response which scored above 0 pts
Incorrect: Any response which scored 0 pts including Don’t know

Percentage may not add up to 100% due to rounding

B9. Proximity to downed power line

How close do you believe you can safely come to a downed overhead power line, such as a downed line caused by a storm or accident? Would you say …

Response	Gender Male	Gender Female	Age 18-24	Age 25-34	Age 35-44	Age 45-54	Age 55-64	Age 65+
You can safely touch a downed overhead power line	0.9%	0.0%	0.0%	0.0%	0.0%	2.0%	0.0%	0.0%
Less than 1 metre (i.e. less than 3 feet)	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%
1 to less than 5 metres (i.e. 3 to less than 16 feet)	4.4%	1.9%	0.0%	0.0%	0.0%	4.1%	6.5%	5.5%
5 metres to less than 10 metres (i.e. 16 feet to less than 33 feet)	23.1%	5.7%	16.9%	24.5%	19.3%	8.0%	9.4%	10.1%
You should maintain a distance of 10 metres or more (i.e. 33 feet or more)	70.2%	91.4%	83.1%	75.5%	80.7%	83.9%	83.3%	81.2%
Don't know	1.2%	1.0%	0.0%	0.0%	0.0%	2.0%	0.8%	2.8%

Percentage may not add up to 100% due to rounding

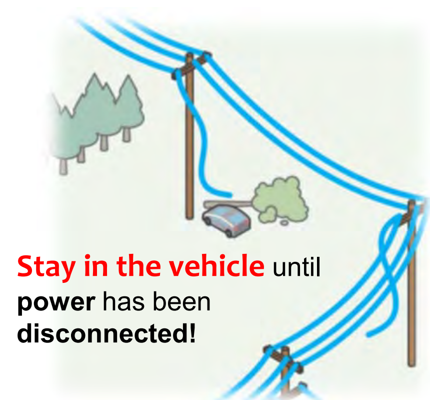
B10. Actions taken in vehicle in contact with wires

If you were in a vehicle – such as a car, bus, or truck – and an overhead power line came down on top of it, which of the following options do you believe is generally safer?

Response	Score	% of respondents
Get out quickly and seek help	0.00 pts	**12.5%**
Stay in the vehicle until power has been disconnected from the line	1.00 pts	**86.9%**
Don’t know	0.00 pts	**0.5%**

CORRECT ✓ 86.9%

INCORRECT ✗ 13.9%



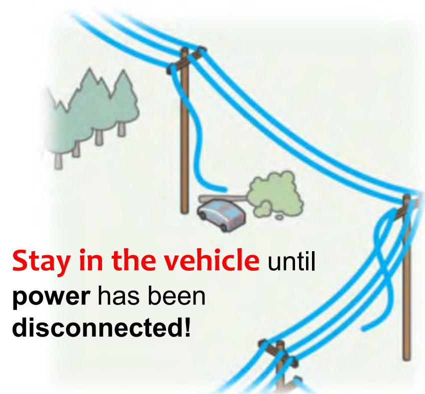
Correct: Any response which scored above 0 pts
Incorrect: Any response which scored 0 pts including Don’t know

Percentage may not add up to 100% due to rounding

B10. Actions taken in vehicle in contact with wires

If you were in a vehicle – such as a car, bus, or truck – and an overhead power line came down on top of it, which of the following options do you believe is generally safer?

Response	Gender Male	Gender Female	Age 18-24	Age 25-34	Age 35-44	Age 45-54	Age 55-64	Age 65+
Get out quickly and seek help	10.6%	14.3%	0.0%	37.8%	5.6%	17.3%	6.2%	6.3%
Stay in the vehicle until power has been disconnected from the line	88.9%	85.2%	100.0%	62.2%	94.4%	82.7%	92.0%	92.6%
Don't know	0.5%	0.5%	0.0%	0.0%	0.0%	0.0%	1.8%	1.1%



Percentage may not add up to 100% due to rounding

Niagara Peninsula Energy
Public Awareness of Electrical Safety Report
Demographics

In what age category do you fall into?

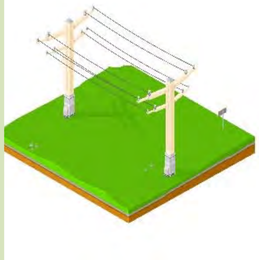
Response	% of respondents Based on Census data
18 to 24	11.3%
25 to 34	15.5%
35 to 44	15.4%
45 to 54	19.9%
55 to 64	17.7%
65 or older	20.2%

Gender

Response	% of respondents Based on Census data
Male	47.4%
Female	52.6%

Percentage may not add up to 100% due to rounding

Niagara Peninsula Energy
Public Awareness of Electrical Safety Report
Demographics



Does your job regularly cause you to come close to energized power lines?

Response	% of respondents
Yes	8.0%
No	91.9%
Don't know	0.1%

Proceed to the following question only If Respondent answers 'Yes' …

Do you work in any of the following fields?

Response	% of respondents
Transportation	6.1%
General labour	16.8%
Construction or outdoor trades	24.3%
Electrician	13.6%
Other	25.3%
Don't know/Prefer not to say	14.0%

Percentage may not add up to 100% due to rounding

Niagara Peninsula Energy
Public Awareness of Electrical Safety Report
Demographics

How would you describe your primary residence? Would you say…

Response	% of respondents
A fully-detached home	70.1%
A semi-detached home	5.1%
A townhome or row house	5.2%
An apartment or condo building less than 5 storeys	15.1%
An apartment or condo building 5 storeys or higher	1.9%
A farm	0.9%
Other	1.8%

Does your primary residence receive electricity through overhead wires or underground cables?

Response	% of respondents
Overhead wires	37.1%
Underground cables	50.1%
Don’t know	12.8%

Percentage may not add up to 100% due to rounding

Niagara Peninsula Energy

GSC1. Could you tell me what would be your primary source for finding information about electricity safety?

Response	Overall	Gender Male	Gender Female	Age 18-24	Age 25-34	Age 35-44	Age 45-54	Age 55-64	Age 65+
Local utility website	33.1%	28.8%	37.0%	41.5%	37.8%	27.9%	34.1%	30.4%	30.1%
Electrical Safety Authority	16.4%	16.2%	16.6%	24.6%	0.0%	21.9%	17.7%	20.2%	15.7%
Online search	29.9%	32.1%	27.9%	33.9%	37.8%	44.7%	27.0%	29.5%	13.4%
Social media	1.2%	1.6%	1.0%	0.0%	0.0%	0.0%	3.9%	0.8%	1.6%
Relative or friend	8.3%	10.8%	6.0%	0.0%	24.5%	3.0%	3.9%	6.2%	10.8%
Other	9.5%	9.3%	9.6%	0.0%	0.0%	2.6%	11.6%	11.9%	23.0%
Don't Know/ refused/ Prefer not to say	1.6%	1.2%	2.0%	0.0%	0.0%	0.0%	1.8%	1.0%	5.4%

GridSmartCity renewing energy

Additional question(s) for Grid Smart City Clients

Percentage may not add up to 100% due to rounding

Niagara Peninsula Energy

GSC2. Do you have any children, living with you, who are 6 to 13 years old?

Response	% of respondents
Yes	20.2%
No	79.7%
Did not answer	0.1%

GSC3. Have you had a conversation within the last year with your child or children about the dangers of powerlines and playing near electrical equipment?

Response	% of respondents
Yes	57.1%
No	42.9%
Did not answer	0.0%

GridSmartCity renewing energy

Additional question(s) for Grid Smart City Clients

Percentage may not add up to 100% due to rounding

UtilityPULSE, through polls and surveys, provides executives and managers with feedback that assists in making both strategic and operational decisions. You know lots of companies that can gather data and provide a report. We believe that by specializing in the utility sector with our polls and surveys, you get stronger analysis of data and answers to key questions that help you formulate key strategies to assist your leaders in creating a better place to work and a better place to do business with.

UtilityPULSE is uniquely positioned to help your utility get feedback from Customers, through its Annual Electric Utility Customer Satisfaction Survey or customized research designed for you. In addition, we understand what it takes to create an organization where employees are engaged and enthusiastic about customers and the work that they do. Knowing what is going on with your customers and employees is one thing, doing something about it is another. We get paid for, and earn our clients' loyalty by, delivering objective insights with actionable recommendations; accomplished when every step of the process is completed with professionalism and pride. Our mission is to help you and your leadership team move from knowing to doing while improving performance and creating value to your customers, employees, stakeholders and the public at large.

Your personal contact is:
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E-mail: sidridgley@utilitypulse.com
www.utilitypulse.com

Niagara Peninsula Energy

Public Awareness of Electrical Safety
March 2016

UtilityPULSE
Public Awareness of Electrical Safety Report

This is privileged and confidential material and no part may be used other than the intended purpose of providing a score for the Ontario Energy Board Scorecard.

Results are based on a telephone survey (Random Digit Dialing) among 400 Members of the General Public,18 years of age or older, residing within the LDC's geographic service territory. The data has been statistically weighted according to Canadian census figures (2011) for age, gender and region.

Scores in this report follow Appendix A: Scorecard Methodology and Implementation Guide published by the Ontario Energy Board November 25, 2015.

The questions used in the survey follow Appendix B: Biannual Standardized Scorecard Public Awareness of Electrical Safety Telephone Questionnaire published by the Ontario Energy Board November 25, 2015.

All comments and questions should be addressed to:

UtilityPULSE
Toll free: 1-888-291-7892 or Local: 905-895-7900
Project lead: Sid Ridgley
Email: sidridgley@utilitypulse.com
March, 2016

UtilityPULSE

UtilityPULSE
Public Awareness of Electrical Safety Report
Executive Summary

Niagara Peninsula Energy's Public Safety Awareness Index Score is 84 %.

This is the first year for compiling data to measure the level of awareness of key electrical safety precautions among the public within the electricity distributor's service territory. Results are based on a telephone survey (Random Digit Dialing) among 400 Members of the General Public,18 years of age or older, within the LDC's geographic service territory. The data has been statistically weighted according to Canadian census figures (2011) for age, gender and region.

The six core measurement questions correspond to the six most frequent incidents involving utility equipment in Ontario over the last decade. When looking at the distribution of responses for the six core measurement questions here are some of the key observations and recommendations going forward:

Question B5: Likelihood to *"call before you dig" [56.6% scored 1.00 pts]*
56.6% would 'definitely' and 22.2% were 'very likely' to call to locate electrical or other underground lines. While these figures indicate that many of your service territory's population would 'call before they dig', the remainder did not see this as a 'must do'. Even of those respondents who did reply they would definitely or very likely make the call, it is not clear if they would call because they were exerting due diligence for their property and household project OR if they were knowledgeable in the fact that this is the law that is in place.

Any education put forth on this core measurement must emphasize that it is the law that one must 'call before you dig'.

UtilityPULSE
Public Awareness of Electrical Safety Report
Executive Summary (continued)

Question B6: Impact of touching a power line *[95.9% scored 1.00 pts]*
95.9% knew that is 'very dangerous' and 2.3% believed it is 'somewhat dangerous' to touch an overhead power line with their body or any object.

Any education put forth on this core measurement must continue to emphasize & re-emphasize the perils associated with touching a power line. The key message that needs to continue to be driven to the public on this measurement is clear and simple: It is very dangerous to touch an overhead power line with your body or any object.

Question B7: Proximity to overhead power line *[20.7% scored 1.00 pts]*
This was one of two questions that contained a concept of measurement of distance from a power line constituting safe proximity. 20.7% indicated that they believed that there needed to be a distance of 3 metres to less than 6 metres and 54.3% indicated a distance of 6 metres or more to safely come close to an overhead power line with their body or an object. While this indicates there is knowledge that there needs to be a "certain" proximity maintained from an overhead power line, the exact measurement is not quite readily known. It is also indicative that while most people believed a "certain" distance was required, it is not clear how many chose the higher distance because of a prevailing thought that 'the further away the safer you are'.

While being further away i.e. 6 metres or more is not technically incorrect, the point of this question is to educate the public that there is a reasonable distance that needs to be maintained. Any education put forth on this core measurement must clearly emphasize that a person can be as close as 3 metres to safely come close to an overhead power line while undertaking outdoor activities. This message whether in print or graphically depicted has to be clear and identifiable as not to confuse with the second question concerning distance from a 'downed' powerline (QB9). A catchy phrase or tag line to help the public remember is worthwhile.

For example, the tag line "On a ladder or climbing trees, 3 to 6 metres you need to be" or " On a ladder or climbing trees, at least 3 metres you need to be" ; either tag line noted next to an image of a person on a ladder in proximity of an overhead power line helps instill the message. Remember, you are trying to get the public at large to learn & remember the minimum distance is 3 metres to an overhead power line.

UtilityPULSE
Public Awareness of Electrical Safety Report
Executive Summary (continued)

Question B8: Danger of tampering with electrical equipment *[90.7% scored 1.00 pts]*
90.7% knew that is 'very dangerous' to tamper with electrical equipment, while 7.3% believed it was 'somewhat dangerous'.

Any education put forth on this core measurement must continue to emphasize & re-emphasize the perils associated with touching or tampering with electrical equipment. This is a no play zone for children and/or pets and in general all persons need to leave the electrical equipment alone.

Question B9: Proximity to downed power line *[78.8% scored 1.00 pts]*
This is the second question containing a concept of measurement of distance, this time from a downed power line constituting safe proximity. 78.8% indicated that a distance of 10 metres or more needed to be maintained from a downed power line. As in QB7, while this indicates there is knowledge that there needs to be a "certain" proximity maintained from a downed power line, it is not clear how many chose the higher distance because of a prevailing thought that 'the further away the safer you are'. In this instance however, choosing the furthest distance is the correct answer.

The point of this question is to educate the public that there is a reasonable distance that needs to be maintained from a downed power line and this distance is at least 10 metres. This message whether emphasized in print or graphically depicted has to be clear and identifiable as not to confuse with the question concerning distance of 3 metres from an 'overhead' powerline (QB7). Again, a catchy phrase or tag line to help the public remember is worthwhile.

For example, the tag line "Downed line on the floor, stay away 10 metres or more" or " Downed line on the ground, back 10 metres if standing around" ; either tag line noted next to an image of a person on a ladder in proximity of an overhead power line helps instill the message.

Remember, you are trying to get the public at large to learn & remember the minimum distance from a downed line is 10 metres.

UtilityPULSE
Public Awareness of Electrical Safety Report
Executive Summary (continued)

Question B10: Actions taken in vehicle in contact with wires *[90.0% scored 1.00 pts]*
90.0% responded the safer action in this case would be to ‘stay in the vehicle until power was disconnected from the line’.

Any education put forth on this core measurement must continue to emphasize & re-emphasize the harm associated with stepping out of a vehicle that is in contact with a downed power line. While some people instinctually feel that getting out and seeking help would be the proper thing to do, they need to be educated that staying in the vehicle is their best and safest option until the power is disconnected.

Conclusion:
This first year of surveying the public in your service territory about electrical safety shows that many do have good knowledge or have received some information pertaining to the 6 core measurement questions. Niagara Peninsula Energy’s Public Safety Awareness Index Score is 84%.

The OEB has indicated that the performance target for public awareness of electrical safety will be established once three years of data is gathered. In the meantime, your LDC will be expected to demonstrate the impact of your public education efforts through biannual surveying of adults residing in your service territory.

As you begin or continue to develop safety awareness campaigns, we recommend that you look through this report along with your data report to see where, among the population, awareness levels are lower and where outreach can be targeted. Focus on the messages that you need to drive home to help the public learn and remember. We also recommend that you share your results with your employees, especially those who may be in contact with outside workers, as they too can help spread the safety message.

Sid Ridgley

UtilityPULSE

Niagara Peninsula Energy
Public Safety Awareness Index Score

This **index score** is calculated using the following formulas:

Step 1: Add each individual respondent's key measurement questions using the provided response values.

	B5
+	B6
+	B7
+	B8
+	B9
+	B10
=	**Individual respondent's cumulative score**

Step 2:
Individual respondent's cumulative score / # of sections
= Respondent Standardized Score

Step 3:
Summation of all **"Respondent Standardized Scores" /** n-size (i.e. total sample size)
= Raw Index Score

Step 4:
Raw Index Score × 100 = **Index Score** (bound between 0-100%)

Responses will be indexed to create a single comparable Public Safety Awareness Score

In some cases, a respondent will have no intention of undertaking a project that requires digging. In this case, the index is based on only the 5 relevant sections of scorecard. This question (B5) will be removed from the calculation.

Niagara Peninsula Energy

Public Safety Awareness Index Score

84%

B5. Likelihood to *"call before you dig"*

If you were to undertake a household project that required digging – such as planting a tree or building a deck – how likely are you to call to locate electrical or other underground lines?

Response	Score	% of respondents
Definitely	1.00 pts	56.6%
Very likely	0.75 pts	22.2%
Somewhat likely	0.50 pts	7.9%
Not very likely	0.00 pts	3.8%
Not at all likely	0.00 pts	5.7%
I would not undertake a project that required digging	omitted[1]	2.6%
Don't know	0.00 pts	1.2%

[1]Note: In some cases, a respondent will have no intention of undertaking a project that requires digging. In this case, the index is based on only the five relevant sections of the scorecard. This question will be removed from the calculation of the Individual Respondent's cumulative score.

86.7%

13.3%

Correct: Any response which scored above 0 pts
Incorrect: Any response which scored 0 pts including Don't know

ON1CALL
CALL BEFORE YOU DIG

*Planting a tree, building a deck or a fence? Contact **ON1Call** first to get a locate so you can dig safely.*

B5. Likelihood to *"call before you dig"*

If you were to undertake a household project that required digging – such as planting a tree or building a deck – how likely are you to call to locate electrical or other underground lines?

Response	Gender Male	Gender Female	Age 18-24	Age 25-34	Age 35-44	Age 45-54	Age 55-64	Age 65+
Definitely	54.5%	58.5%	28.6%	68.2%	53.2%	66.7%	62.0%	51.3%
Very likely	19.8%	24.4%	42.9%	15.5%	27.8%	13.1%	17.8%	24.6%
Somewhat likely	9.6%	6.3%	7.3%	10.9%	7.0%	8.2%	9.1%	5.1%
Not very likely	5.4%	2.3%	14.3%	0.0%	3.3%	3.6%	1.8%	3.0%
Not at all likely	7.0%	4.6%	7.0%	5.4%	1.7%	4.8%	4.6%	10.3%
I would not undertake a project that required digging[1]	2.9%	2.3%	0.0%	0.0%	1.7%	2.4%	4.8%	5.0%
Don't know	0.8%	1.6%	0.0%	0.0%	5.3%	1.2%	0.0%	0.7%

[1]Note: In some cases, a respondent will have no intention of undertaking a project that requires digging. In this case, the index is based on only the five relevant sections of the scorecard. This question will be removed from the calculation of the Individual Respondent's cumulative score.

ON1CALL
CALL BEFORE YOU DIG

*Planting a tree, building a deck or a fence? Contact **ON1Call** first to get a locate so you can dig safely.*

B6. Impact of touching a power line

How dangerous do you believe it is to touch – with your body or any object – an overhead power line?

Response	Score	% of respondents
Very dangerous	1.00 pts	95.9%
Somewhat dangerous	0.50 pts	2.3%
Not very dangerous	0.00 pts	1.0%
Not at all dangerous	0.00 pts	0.3%
Don't know	0.00 pts	0.4%

98.2%

1.8%

Correct: Any response which scored above 0 pts
Incorrect: Any response which scored 0 pts including Don't know

B6. Impact of touching a power line

How dangerous do you believe it is to touch – with your body or any object – an overhead power line?

Response	Gender Male	Gender Female	Age 18-24	Age 25-34	Age 35-44	Age 45-54	Age 55-64	Age 65+
Very dangerous	95.6%	96.2%	92.7%	100.0%	98.2%	97.5%	92.2%	94.5%
Somewhat dangerous	3.2%	1.5%	7.3%	0.0%	0.0%	1.2%	4.8%	1.9%
Not very dangerous	0.0%	2.0%	0.0%	0.0%	1.8%	0.0%	2.1%	1.9%
Not at all dangerous	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%	0.7%
Don't know	0.5%	0.4%	0.0%	0.0%	0.0%	1.2%	0.0%	1.0%

B7. Proximity to overhead power line

When undertaking outdoor activities – such as, standing on a ladder, cleaning windows or eaves, climbing or trimming trees – how close do you believe you can safely come to an overhead power line with your body or an object? Would you say …

Response	Score	% of respondents
You can safely touch an overhead power line	0.00 pts	0.5%
Less than 1 metre (i.e. less than 3 feet)	0.00 pts	2.2%
1 to less than 3 metres (i.e. 3 to less than 10 feet)	0.00 pts	16.6%
3 metres to less than 6 metres (i.e. 10 feet to less than 20 feet)	1.00 pts	20.7%
You should maintain a distance of 6 metres or more (i.e. 20 feet or more)	0.75 pts	54.3%
Don't know	0.00 pts	5.8%

75.0%

25.0%

Correct: Any response which scored above 0 pts
Incorrect: Any response which scored 0 pts including Don't know

B7. Proximity to overhead power line

When undertaking outdoor activities – such as, standing on a ladder, cleaning windows or eaves, climbing or trimming trees – how close do you believe you can safely come to an overhead power line with your body or an object? Would you say …

Response	Gender Male	Gender Female	Age 18-24	Age 25-34	Age 35-44	Age 45-54	Age 55-64	Age 65+
You can safely touch an overhead power line	0.6%	0.4%	0.0%	0.0%	0.0%	0.0%	1.1%	1.4%
Less than 1 metre (i.e. less than 3 feet)	2.7%	1.7%	0.0%	0.0%	5.1%	3.6%	2.0%	1.7%
1 to less than 3 metres (i.e. 3 to less than 10 feet)	18.9%	14.5%	14.3%	24.8%	12.1%	14.5%	15.2%	18.3%
3 metres to less than 6 metres (i.e. 10 feet to less than 20 feet)	22.3%	19.3%	42.6%	25.6%	23.9%	12.1%	16.5%	14.5%
You should maintain a distance of 6 metres or more (i.e. 20 feet or more)	53.7%	54.8%	43.1%	45.0%	55.3%	64.0%	60.5%	51.8%
Don't know	1.8%	9.4%	0.0%	4.6%	3.6%	5.9%	4.8%	12.3%

B8. Danger of tampering with electrical equipment

Some electrical utility equipment is located on the ground, such as locked steel cabinets that contain transformers.

How dangerous do you believe it is to try to open, remove contents, or touch the equipment inside? Would you say …

Response	Score	% of respondents
Very dangerous	1.00 pts	90.7%
Somewhat dangerous	0.50 pts	7.3%
Not very dangerous	0.00 pts	0.6%
Not dangerous at all	0.00 pts	0.6%
Don't know	0.00 pts	0.8%

98.1%

1.9%

Correct: Any response which scored above 0 pts
Incorrect: Any response which scored 0 pts including Don't know

B8. Danger of tampering with electrical equipment

Some electrical utility equipment is located on the ground, such as locked steel cabinets that contain transformers.

How dangerous do you believe it is to try to open, remove contents, or touch the equipment inside? Would you say …

Response	Gender Male	Gender Female	Age 18-24	Age 25-34	Age 35-44	Age 45-54	Age 55-64	Age 65+
Very dangerous	92.5%	89.2%	100.0%	84.5%	87.8%	94.1%	93.9%	86.6%
Somewhat dangerous	6.6%	8.0%	0.0%	15.5%	10.4%	4.8%	4.1%	8.2%
Not very dangerous	0.0%	1.1%	0.0%	0.0%	0.0%	0.0%	0.0%	2.9%
Not dangerous at all	0.6%	0.5%	0.0%	0.0%	1.8%	0.0%	0.9%	0.7%
Don’t know	0.3%	1.2%	0.0%	0.0%	0.0%	1.2%	1.1%	1.7%

B9. Proximity to downed power line

How close do you believe you can safely come to a downed overhead power line, such as a downed line caused by a storm or accident? Would you say …

Response	Score	% of respondents
You can safely touch a downed overhead power line	0.00 pts	0.7%
Less than 1 metre (i.e. less than 3 feet)	0.00 pts	1.2%
1 to less than 5 metres (i.e. 3 to less than 16 feet)	0.00 pts	5.7%
5 metres to less than 10 metres (i.e. 16 feet to less than 33 feet)	0.00 pts	11.3%
You should maintain a distance of 10 metres or more (i.e. 33 feet or more)	1.00 pts	78.8%
Don’t know	0.00 pts	2.4%

78.8%

21.2%

Correct: Any response which scored above 0 pts
Incorrect: Any response which scored 0 pts including Don’t know

B9. Proximity to downed power line

How close do you believe you can safely come to a downed overhead power line, such as a downed line caused by a storm or accident? Would you say …

Response	Gender Male	Gender Female	Age 18-24	Age 25-34	Age 35-44	Age 45-54	Age 55-64	Age 65+
You can safely touch a downed overhead power line	0.5%	0.7%	0.0%	0.0%	1.7%	0.0%	0.0%	1.9%
Less than 1 metre (i.e. less than 3 feet)	0.5%	1.7%	0.0%	4.6%	1.7%	0.0%	0.0%	1.0%
1 to less than 5 metres (i.e. 3 to less than 16 feet)	5.5%	5.8%	7.0%	5.4%	5.1%	3.5%	6.9%	6.6%
5 metres to less than 10 metres (i.e. 16 feet to less than 33 feet)	11.3%	11.2%	0.0%	15.5%	13.8%	9.5%	10.4%	14.8%
You should maintain a distance of 10 metres or more (i.e. 33 feet or more)	80.7%	77.1%	93.0%	74.4%	74.2%	82.2%	81.6%	72.1%
Don't know	1.3%	3.4%	0.0%	0.0%	3.6%	4.8%	1.1%	3.6%

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B10. Actions taken in vehicle in contact with wires

If you were in a vehicle – such as a car, bus, or truck – and an overhead power line came down on top of it, which of the following options do you believe is generally safer?

Response	Score	% of respondents
Get out quickly and seek help	0.00 pts	7.7%
Stay in the vehicle until power has been disconnected from the line	1.00 pts	90.0%
Don't know	0.00 pts	2.2%

90.0%

10.0%

Correct: Any response which scored above 0 pts
Incorrect: Any response which scored 0 pts including Don't know

B10. Actions taken in vehicle in contact with wires

If you were in a vehicle – such as a car, bus, or truck – and an overhead power line came down on top of it, which of the following options do you believe is generally safer?

Response	Gender Male	Gender Female	Age 18-24	Age 25-34	Age 35-44	Age 45-54	Age 55-64	Age 65+
Get out quickly and seek help	3.8%	11.3%	14.0%	4.6%	19.2%	6.0%	2.8%	3.9%
Stay in the vehicle until power has been disconnected from the line	95.5%	85.1%	86.0%	90.7%	80.8%	92.8%	95.2%	91.5%
Don't know	0.6%	3.7%	0.0%	4.6%	0.0%	1.2%	2.0%	4.6%

Niagara Peninsula Energy Public Awareness of Electrical Safety Report Demographics

In what age category do you fall into?

Response	% of respondents Based on Census data
18 to 24	11.3%
25 to 34	15.5%
35 to 44	15.4%
45 to 54	19.9%
55 to 64	17.7%
65 or older	20.2%

Gender

Response	% of respondents Based on Census data
Male	47.4%
Female	52.6%

Niagara Peninsula Energy Public Awareness of Electrical Safety Report

Demographics

Does your job regularly cause you to come close to energized power lines?

Response	% of respondents
Yes	6.0%
No	93.3%
Don’t know	0.7%

Proceed to the following question only If Respondent answers ‘Yes’ ...

Do you work in any of the following fields?

Response	% of respondents
Transportation	25.5%
General labour	4.0%
Construction or outdoor trades	23.6%
Electrician	20.2%
Other	26.7%
Don’t know/Prefer not to say	0.0%

Niagara Peninsula Energy Public Awareness of Electrical Safety Report Demographics

How would you describe your primary residence? Would you say…

Response	% of respondents
A fully-detached home	68.5%
A semi-detached home	9.4%
A townhome or row house	6.0%
An apartment or condo building less than 5 storeys	11.2%
An apartment or condo building 5 storeys or higher	3.9%
A farm	0.3%
Other	0.9%

Does your primary residence receive electricity through overhead wires or underground cables?

Response	% of respondents
Overhead wires	41.6%
Underground cables	49.4%
Don't know	9.0%

UtilityPULSE, through polls and surveys, provides executives and managers with feedback that assists in making both strategic and operational decisions. You know lots of companies that can gather data and provide a report. We believe that by specializing in the utility sector with our polls and surveys, you get stronger analysis of data and answers to key questions that help you formulate key strategies to assist your leaders in creating a better place to work and a better place to do business with.

UtilityPULSE is uniquely positioned to help your utility get feedback from Customers, through its Annual Electric Utility Customer Satisfaction Survey or customized research designed for you. In addition, we understand what it takes to create an organization where employees are engaged and enthusiastic about customers and the work that they do. Knowing what is going on with your customers and employees is one thing, doing something about it is another. We get paid for, and earn our clients' loyalty by, delivering objective insights with actionable recommendations; accomplished when every step of the process is completed with professionalism and pride. Our mission is to help you and your leadership team move from knowing to doing while improving performance and creating value to your customers, employees, stakeholders and the public at large.

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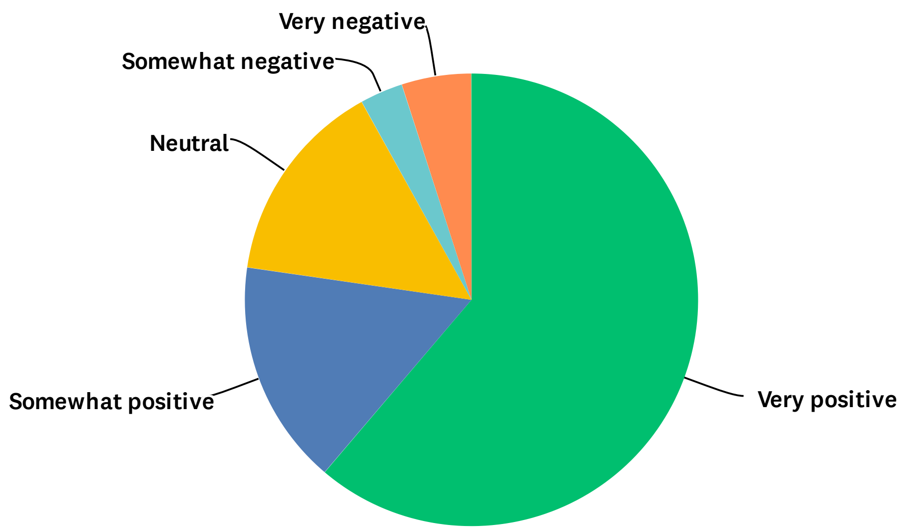
Appendix 1-20

2018 and 2019 Customer Service Transactional Survey Results

Q1 Overall, how would you rate the quality of your customer service experience?

Answered: 423 Skipped: 7



ANSWER CHOICES	RESPONSES	
Very positive	61.23%	259
Somewhat positive	16.08%	68
Neutral	14.66%	62
Somewhat negative	3.07%	13
Very negative	4.96%	21
TOTAL		423

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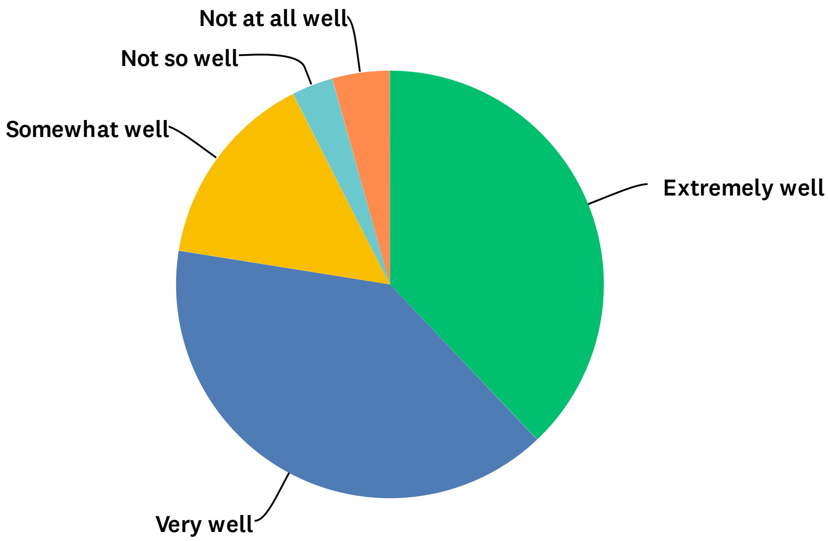
Q2 How well did we understand your questions and concerns?

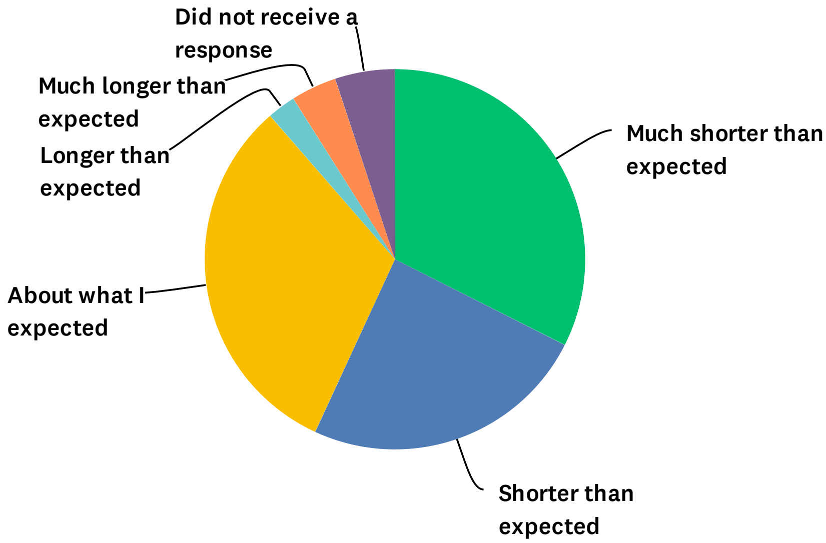
Answered: 414 Skipped: 16



ANSWER CHOICES	RESPONSES	
Extremely well	37.92%	157
Very well	39.61%	164
Somewhat well	14.98%	62
Not so well	3.14%	13
Not at all well	4.35%	18
TOTAL		414

Q3 How much time did it take us to address your questions and concerns?

Answered: 413 Skipped: 17



ANSWER CHOICES	RESPONSES	
Much shorter than expected	32.45%	134
Shorter than expected	24.46%	101
About what I expected	31.72%	131
Longer than expected	2.42%	10
Much longer than expected	3.87%	16
Did not receive a response	5.08%	21
TOTAL		413

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Q4 Do you have any other comments, questions, or concerns? Please provide a reference so that we can contact you to follow up on your concerns.

Answered: 139 Skipped: 291

2018 Transactional Survey Responses

Customer Service-Positive I am a new user and I found Melissa very courteous and efficient. I was able to settle my account within minutes.	12/28/2018 4:18 PM
Feedback - Positive My interaction was brief and information seeking and was perfectly acceptable to me. The above questions don't seem that relevant to my interaction.	12/27/2018 2:57 PM
Reliability - Positive I am very happy to report that we have a very few power interruptions in the 13 years at this location. Only 1 transformer replaced due to animal activity. Good Job.	12/20/2018 8:45 PM
Customer Service-Positive Always good support and service from our key contact, Sean Perry.	12/20/2018 1:09 PM
My Account- Negative Website - Negative NPE customer website is pathetic, outdated and in NO way user friendly. It needs a serious update to the 21st century!	12/19/2018 10:21 AM
Bill Issues Negative to Positive It has been somewhat frustrating dealing with NPEI some nice we may bed into the area. We have not received a bill in the mail and therefore we are late in saying it. I have not received any email notifications about my bill. I believe the postal strike delayed the receiving of the bill. I hope that service will improve now that we are caught up with our billing and signed up for electronic billing. Rosalie	12/6/2018 2:06 PM
Customer Service-Positive Thank you so much. I'm a relatively new customer (June 2018) and because of the new meter system I've had a couple hiccups in billing - but both times i've had to check in, my problems were solved very quickly and everyone I've spoken with has been so pleasant. Awesome service, thanks again!	12/5/2018 4:37 PM
My Account- Negative I have never had to call or ask questions, so I cannot truthfully answer any of these questions. However, your website is not very user friendly, and I am continually seeing an old account. I can navigate most websites without an issue, but yours is not, as I said, user friendly.	10/22/2018 4:26 PM
Customer Service-Positive Service was so good I wish you worked for Bell too	10/18/2018 10:51 AM
Customer Service-Positive Great Experience	10/14/2018 8:30 AM
Feedback - Positive I have had no issues.	10/14/2018 8:30 AM
Customer Service-Positive The linemen working are always friendly and willing to answer any questions I may have.	10/12/2018 10:53 AM
Customer Service-Positive I was struggling to pay my bill and the staff immediately set up a plan to help me and I have not had any issues. Thank you!	10/10/2018 6:49 PM
My Account- Negative It would be greatly appreciated, if, on your registration page examples were given for the way you want the meter number and Postal code...Thanks	10/9/2018 1:50 PM
Customer Service-Positive Extremely professional and very helpful.	10/9/2018 2:03 AM
Customer Service-Positive keep going what you do. Good job	10/3/2018 11:28 AM
Customer Service-Positive Service was great! never caught Jaime last name! Excellent job!	9/29/2018 12:34 PM
EBill View- Negative I haven't ever needed to speak to your customer service dept???? why the survey? one thing you need to change is your e-billing! I just signed up for it and am not impressed! when you send the e-bill why don't you have a quick link to your website so we can just tap it and go there instead of having to find your website then loading it etc!	9/28/2018 10:30 PM
EBill View- Negative It would be nice if our bills were attached to the emails instead of having to go into your site.	9/27/2018 2:14 PM
Customer Service-Positive Great LDC. Great Service.	9/13/2018 8:52 AM
Customer Service-Positive execellet	9/9/2018 9:18 PM
EBill - Positive I love getting online bills it keeps me up to date on my account.	8/21/2018 8:18 PM

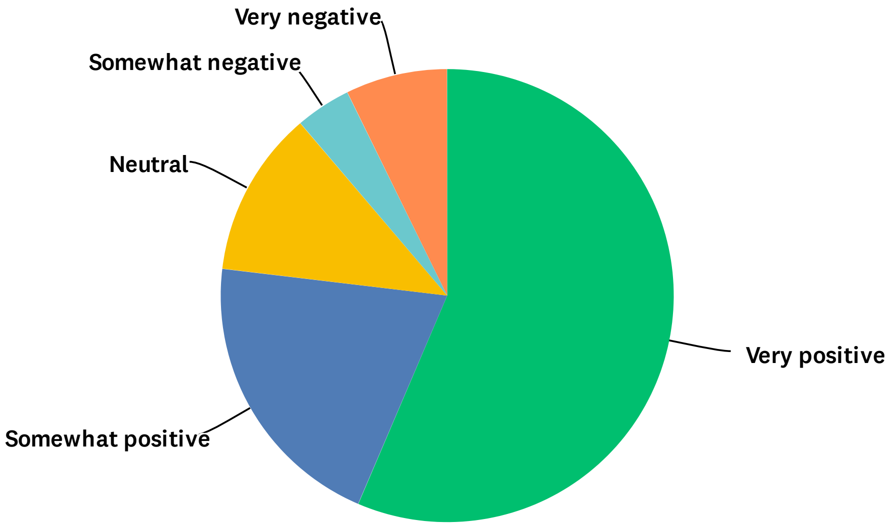
Customer Service-Positive As an electrical contractor of 35 years, I interact with many utilities in the Niagara Region. I wish a great number of them were as contractor friendly as yours is. I have been waiting 6 weeks (and several frustrating phone calls) for a similar request to another Niagara utility.	7/9/2018 10:32 AM
Customer Service-Positive I was concerned about late charges on my account as an ex roommate had abused his power consumption privileges and my bill exploded. I'm on a disability allowance and the bill was over what my budget could afford. The customer service representative was very kind and sympathetic to my situation and told me that late charges were not billed to people on a disability pension. I had no idea that NPEI was so compassionate and understanding. I am extremely grateful for this consideration. Thank you	7/9/2018 8:37 AM
Payment Options-Negative make your bill paying easier, by direct on line banking, instead of credit card run around, with a charge	6/29/2018 5:46 AM
EBill View- Negative I am curios why the link in the email doesn't simply take you to the site to download your bill?	6/28/2018 6:26 PM
Feedback - Positive Nice that I did not get transferred a lot of times	6/14/2018 12:46 PM
Feedback - General Thank you for at least putting the login where it can be found. PLEASE get rid of the inf@npe and title it Hydro bill or something and get rid of the question mark	6/2/2018 4:33 PM
EBill View- Negative My Account- Negative Your web site and the viewing of different accounts (I have several) is NOT user friendly. Each month is a new learning curve. Should be an easier way to navigate the system. Try again anew.	5/31/2018 6:13 PM
Feedback - Negative Your service to reconnect is unreasonable. Time windows?	5/31/2018 3:07 PM
Customer Service-Positive Outage - Momentary Happy overall with the service, except for several times a year it goes off for a couple of minutes.	5/30/2018 10:50 AM
Customer Service-Positive No not really I'm extremely happy with how I'm treated each time I have an issue with npei!!!	5/25/2018 12:31 PM
Customer Service-Positive Special thanks to Heather. She was extremely helpful, personable and very professional.	4/17/2018 12:03 PM
Payment Options-Negative NPEI website to pay bills online is a nightmare. It is not user friendly and it is extremely difficult to access my bills and statements and I am unable to pay my invoice.	4/12/2018 4:47 PM
Customer Service-Positive I was helped by Heather both times I called, she was pleasant ,prompt and addressed my concerns for me	4/12/2018 11:31 AM
Customer Service-Positive The service and assistance provided one of the most pleasant experiences in quite a while! Thank you Heather.	4/11/2018 1:19 PM
My Account- Negative Your website is difficult to navigate - the sign-in spot is not in a logical place, there are no instruction re. how to switch from one account to the other, and I have to type in the URL because the email you send doesn't have a hyperlink.	4/6/2018 12:19 PM
Feedback - Negative it has to be better	4/4/2018 11:02 AM
EBill View- Negative My Account- Negative You are pushing your customers to do everything online. But you do not take into account the customer experience on your web site. I receive and monthly email. There is no link on that email to get to my account easily. But there is a link to this .. to funny. When you submit a question you get back a cut and paste answer. No real info. The response should be .. Good suggestion .. we plan to have your suggestion in place my May 2018 email cycle.	4/2/2018 8:54 AM

My Account- Negative Website - Negative Your website is difficult to navigate and the invoices are not easy to access and print out for my records.	3/20/2018 11:06 AM
Feedback - Positive No all is well	3/19/2018 3:14 PM
Customer Service-Positive My Account- Negative Website - Negative I have no problems with your Customer Service. My experience has been always positive. My suggestion is for improvement of your website. I am on eBill and i find your website not user friendly. I am a big user of ebilling system for all my utility bills, phones, etc. Your website needs improvement for Log in, Log off in particular. Not easy to find the Log off button. I always go to npei.ca website to Log in and mistakenly sign in using "Members log in". Npei.ca does not allow customer log in. I have to 'google' "my account.npei.ca" in order to log in.	3/9/2018 7:47 PM
Customer Service-Positive please just keep up the good Service	3/9/2018 11:50 AM
Feedback - General I will forward the pre-authorized form and void cheque under separate cover.	3/9/2018 10:27 AM
Feedback - General Is there any website that I can apply for reduced hydro?	3/8/2018 8:28 PM
Customer Service-Positive Feedback - Negative A very good telephone assistant....I know it's not her issue but had to sit and listen to my frustration. I was asked to send a letter stating the tenant no longer lives there (you can tell they no longer live there because they stopped paying their bill 10 months ago). Np I send the letter...then I'm told we have to wait 10 days before a response is given...we need to move on demolishing the property why are you trying to stall? What's the issue here....send us the forms to the email we gave so we can complete and send back. Why are we waiting 10 days???	3/8/2018 9:25 AM
High Bill My rates are to the point now i cant afford the hike , last 3 months the cost has gone up 30 to 40 dollars more a month . Im using less hydro , but its costing me more. You need to get a handle on that Wynnebag of a preimier, dont vote for her .	3/6/2018 3:27 PM
Customer Service-Positive Very pleased to this point	2/27/2018 8:43 AM
Customer Service-Positive I appreciate the proper letter writing practice in all of your communications. My water bill emails leave so much to be desired in the field of business communication. Thank you for your excellent customer service.	2/26/2018 11:46 PM
Customer Service-Positive The person who provided the service was extremely polite and nice. Good customer contact. Keep up the Good works.	2/23/2018 10:51 AM
Negative to Positive Thx for your prompt attention. I did not receive my paperless bill and rely on it to keep my affairs in order.	2/21/2018 9:52 AM
Feedback - Positive Thank you for your help .	2/10/2018 6:20 PM
EBill View- Negative No paper less billing please	2/5/2018 1:13 PM
Customer Service-Positive Anytime in the past when I've needed to speak with the office, customer service has been excellent, very understanding and helpful in assisting with what I was requesting of them.	2/5/2018 11:30 AM
EBill View- Negative I did sign up for paperless bills. I now get an email but I also still get a paper bill	2/5/2018 8:22 AM
Feedback - General I don't see any information about how the way I receive my bill is changing.	2/4/2018 5:51 PM
EBill View- Negative If you're going paperless I want to see my bill with one click and no login requirement	2/3/2018 8:13 AM
Feedback - Positive All Good	2/3/2018 6:34 AM
Customer Service-Positive Excellent experience when the linemen crew showed up to repair the downed hydro line. Courteous, respectful and kind. The linemen that work in the West Lincoln area are always quick to respond and a pleasure to interact with.	2/2/2018 6:44 PM
Customer Service-Positive Exemplary customer service - great organization!	2/2/2018 6:17 PM

Negative to Positive Took two different service guys to find the problem. But once found everything was taken care of quickly!	2/2/2018 5:02 PM
Feedback - General You sent me to this survey after informing me you are changing how I get my bill. This is a survey for service issues. PS I like my paper bill to keep track of payments, ref number of payment and for taxes. Thanks	2/2/2018 4:38 PM
Feedback - Positive all good	2/2/2018 4:12 PM
Feedback - Positive We have had no issues dealing with any of your staff. Thanks	1/30/2018 7:17 PM
Payment Options-Negative make it easier to pay your bill	1/30/2018 11:23 AM
Feedback - General High Bill Lower rates :)	1/24/2018 3:59 PM

Q1 Overall, how would you rate the quality of your customer service experience?

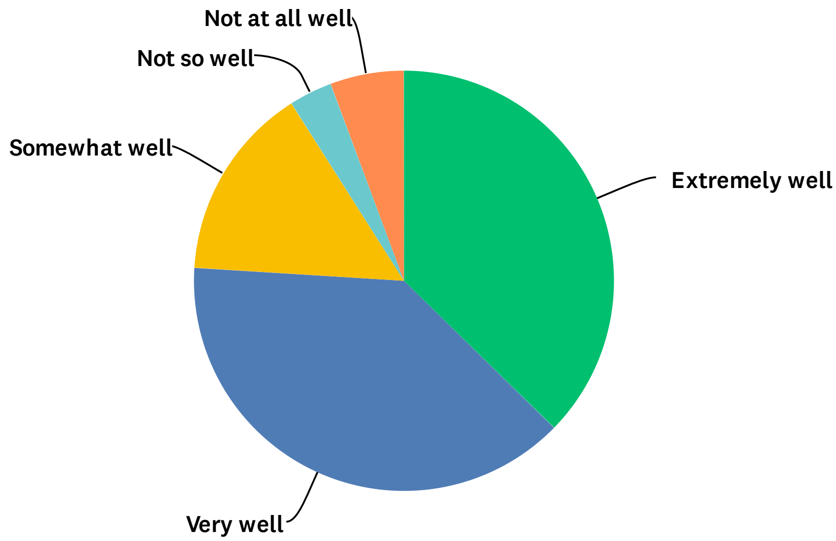
Answered: 303 Skipped: 6



ANSWER CHOICES	RESPONSES	
Very positive	56.44%	171
Somewhat positive	20.46%	62
Neutral	11.88%	36
Somewhat negative	3.96%	12
Very negative	7.26%	22
TOTAL		303

Q2 How well did we understand your questions and concerns?

Answered: 300 Skipped: 9



ANSWER CHOICES	RESPONSES	
Extremely well	37.33%	112
Very well	38.67%	116
Somewhat well	15.00%	45
Not so well	3.33%	10
Not at all well	5.67%	17
TOTAL		300

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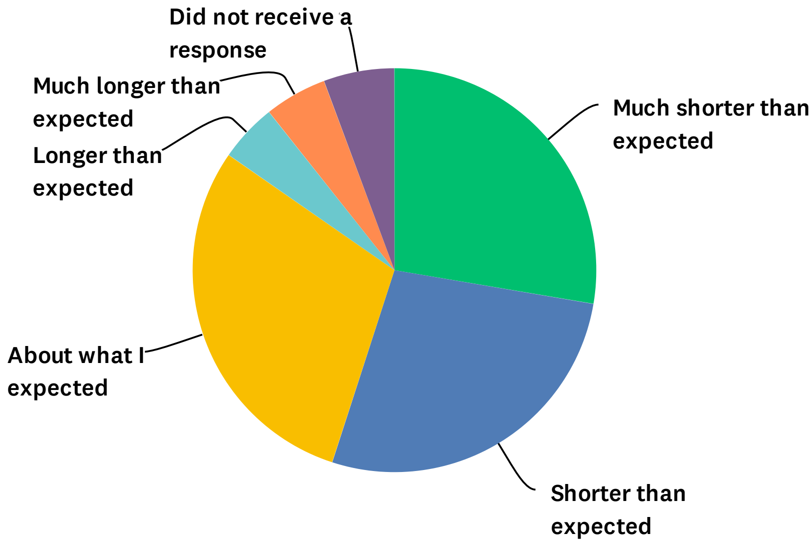
Q3 How much time did it take us to address your questions and concerns?

Answered: 300   Skipped: 9



ANSWER CHOICES	RESPONSES	
Much shorter than expected	27.67%	83
Shorter than expected	27.33%	82
About what I expected	29.67%	89
Longer than expected	4.67%	14
Much longer than expected	5.00%	15
Did not receive a response	5.67%	17
TOTAL		300

Q4 Do you have any other comments, questions, or concerns? Please provide a reference so that we can contact you to follow up on your concerns.

Answered: 111 Skipped: 198

2019 Transactional Survey Responses

Customer Service-Positive Good service	12/10/2019 6:55 PM
Customer Service-Positive Happy with my service so far!	12/9/2019 9:36 PM
Ebill - Negative The level of detail and accuracy in entering personal information in order to login to get my bill leaves more places for error messages and ultimately leaves the end user giving up on trying to actually use online services. Also to receive a message that says you'll get back to me within 10 days is in my opinion far too long	11/28/2019 6:48 AM
Rates - Negative When the prices are going down? Delivery charges etc.	11/26/2019 11:20 AM
Rates - Negative Rates are little bit higher	11/10/2019 8:59 AM
Feedback - Negative As a contractor, trying to organize a disconnection, there should be a short cut through the phone directory, straight to the meter department/ disconnections should be able to be arranged online	11/5/2019 3:37 PM
Customer Service-Positive I spoke with a very pleasant and accommodating customer service rep!	10/15/2019 5:21 PM
My Account- Negative It is a very difficult system to work with.	10/15/2019 8:56 AM
Customer Service-Positive Thank you for your excellent service. Super person on the phone. She was great.	9/28/2019 10:18 AM
EBill View- Negative ebill account details should be shown, not just what is owing, shouldn't have to look it up separately, might go back to regular mail billing	9/24/2019 2:17 PM
No Response We have not had any real problems with our hydro. Keep up the good work.	9/20/2019 3:12 PM
Customer Service-Positive Thank you for your help!	9/14/2019 1:15 PM
Feedback - Positive Not I'm good, thank you!	9/10/2019 9:37 AM
PAP inquiry - positive just want to know how to set up automatic payment from my bank account to ensure no payments are not missed. please help me make that happen	8/29/2019 8:29 PM
Feedback - Positive No issues here!	8/29/2019 4:24 PM
EBill View- Negative My Account- Negative Why do I need a user name and password? That I cant remember. Is someone else going to look at my bill and pay it for me? That would be ok with me.	8/28/2019 1:22 PM
Customer Service-Positive Thank You for a quick reply!!!	8/26/2019 9:48 PM
My Account- Negative Website - Negative Your website and access to actually see our bill is horrible. Every time it wants me to go back to paper bills You did fix your log in access but you need a decent web designer for the rest of it.	8/2/2019 8:41 AM
Feedback - Positive I feel Ok about Niagara Peninsula Services, Thank You	7/24/2019 1:11 PM
Customer Service-Positive Greatly appreciated Laura's assistance in getting our new account set up	7/2/2019 10:42 AM
Customer Service-Positive Great service	7/2/2019 8:42 AM
Customer Service-Positive I`ve never had any problems that you want answers to so as far as I am concerned the service has been good	6/28/2019 5:23 PM
Customer Service-Positive Always been pleased with the service and courteous staff.	6/17/2019 11:32 AM

Customer Service-Positive Extremely helpful Customer Service Staff!	6/10/2019 1:47 PM
Customer Service-Positive very pleased with the service offered on the phone. We are moving from Vancouver to Niagara and the professionalism,ease and consideration that my requests were answered and completed with have made this part of our move very easy. thank you for great service.	5/14/2019 3:24 PM
Customer Service-Positive I like to thank you for great servive	5/7/2019 1:02 PM
High Bill Bill was high and you didn't select my name to draw	4/9/2019 8:39 PM
Customer Service-Positive Negative to Positive I sent an email on March 14 2019 and have not received a reply. I gave a call today and am having the bills emailed as I cannot login. The customer service rep was very helpful.	4/5/2019 2:12 PM
Customer Service-Positive No concerns Larry did a great job	3/14/2019 6:36 PM
Customer Service-Positive Thank you for your service.	3/12/2019 1:33 PM
Customer Service-Positive Excellent representative! She dealt with my request efficiently and pleasantly.	3/8/2019 1:39 PM
EBill View- Negative I think it would be good to have a link in your email that would take us directly to view our current bill. I find theres too many steps to get to it. Thanks, dave	2/28/2019 7:14 AM
Feedback - Positive I will following up with my new account as soon as possible thanks	2/25/2019 9:26 AM
Customer Service-Positive I am very happy with the way the staff handle my Queries and prompt and efficiency of explaining my account. Thanks.	2/22/2019 1:58 PM
Feedback - Positive OESP-Positive Thanks for giving me my OESP credit. It's very much appreciated	2/22/2019 9:44 AM
My Account- Negative Website - Negative Use of NPE website for accounts is very difficult. The site is poorly organized, not user friendly and the technology is outdated by about 20 years.	2/21/2019 3:15 PM
Feedback - Positive Well Done!	2/19/2019 11:09 AM
Customer Service-Positive This request was very easy to accomplish and the staff was very friendly and addressed my request quickly and very polite.	2/13/2019 9:57 AM
High Bill when are you going to lower our inflated costs	1/26/2019 4:39 PM
Feedback - Positive super job	1/26/2019 9:40 AM
Customer Service-Positive Thank you to your customer service representatives Renee and Christine for all their help. They both are very personable and helped clarify my questions and concerns. I look forward to working with NPEI moving forward. Take care.	1/24/2019 2:01 PM
Customer Service-Positive Melissa who helped me was great. Efficient and a great sense of humour which is a lovely mix.	1/17/2019 11:27 AM

Appendix 1-21

Customer Engagement Activities for 2018 and 2019 Report

Customer Engagement Activities 2018 & 2019

February 5,2020

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Customer Engagement: Telecommunications, Email, Online Forms, Billing in person Customer Engagement

Purpose

This document will provide an overview of the activities that can be recorded via Phone IVR (telecommunications); email, online customer facing forms, and annual scheduled billing in person customer engagement.

Outline

The following information can be found within the document.

- Number of e-mails received through info@npei.ca in 2018 and in 2019
- Number of telephone calls into the billing and customer service queue in 2018 and 2019
- Number of online forms filled out in 2018 and 2019
- 2018 and 2019 My Account registrations and usage
- Summary of Customer Connect and the enhanced tools/features it will offer.
- Summary of Contact Manager
- Summary of Class A engagement activities

Emails

An increasing method of communication which is quickly becoming a customer preference is email. Emails are received via a general inbox – info@npei.ca daily. The inbox is monitored throughout the day and the requests are forwarded to the appropriate department, individual or process. Both automated, scheduled processes, direct from customer and customer forms input to info@npei.ca. The number of emails reported represents those that have been processed by customer service and billing; and is not representative of the total number of emails received due to spam, internal process (email is generated from our domain), and internal communication.

Reasons for email include:

- General inquiry from website
- Printable fill in forms from website

- Request for information
- Communication of a move via a lawyer's letter
- Update of account information – i.e. change of name
- Pre-authorization form received
- Declaration form received
- ESA approval
- Connection Agreement received
- Proof of payment
- Request of payment arrangement

The following table outlines the volumes of Email from 2009 to 2018.

Customer Service Emails																
	J	**F**	**M**	**A**	**M**	**J**	**J**	**A**	**S**	**O**	**N**	**D**	**Total**	**Avg per month**	**Annual Increase**	**Annual increase %**
2009	66	73	93	78	76	78	84	69	79	99	145	123	**1063**	164		
2010	179	260	279	223	148	252	222	188	321	332	336	172	**2912**	448	1849	174%
2011	105	187	197	261	242	265	192	237	266	270	228	157	**2607**	401	-305	-10%
2012	218	214	182	232	212	203	199	263	306	268	261	183	**2741**	422	134	5%
2013	251	240	261	285	332	321	401	421	518	502	483	345	**4360**	671	1619	59%
2014	482	433	469	444	421	436	484	388	445	500	540	347	**5389**	829	1029	24%
2015	516	531	648	507	454	504	552	716	666	842	808	547	**7291**	608	1902	35%
2016	618	711	683	713	745	692	650	799	806	909	980	604	**8910**	743	1619	22%
2017	767	710	667	615	620	685	795	752	820	928	944	631	**8934**	745	24	0%
2018	580	535	638	588	712	668	804	812	711	665	667	580	**7960**	663	-974	-11%
2019	660	578	541	900	900	900	900	900	968	989	829	1011	**10076**	840	2116	27%

Telephone Calls into Customer Service and Billing

Communication via Phone IVR is reported by queue. Queues are defined by type of call received and the representatives are assigned based on functional area. The following queues are used:

- All queues: This queue represents all calls that are received by the utility. Reporting of calls answered and abandoned is recorded in reference to all queues.
- All inquiries: This queue is assigned to customer service and billing, meaning that the call goes to the next available representative, regardless of functional department. Inquiries can include balance look up, general information about an account or policy.
- Collections: This queue is assigned to customer service. Calls pertain to active collections, payment arrangements, inquiry on collection policy.
- Customer Service: This queue is assigned to customer service. Calls reported to customer service are consolidated from the individual queues of inquiries, moving, outage, and new service.
- Billing: This is a consolidation of all queues assigned to billing including general queries into billing, payment method, high bill, meter read and the overflow outage calls.
- High Bill: This queue is assigned to customer service and billing, meaning that the call goes to the next available representative, regardless of functional department. A high bill inquiry may relate to increase in consumption or increase in the amount of the bill. The representative will relay trends in usage, as well as, amount of the bill comparing bills from previous periods – same time, last month, last year, etc. If balance is the concern, review of bill and payment history are reviewed with the customer.

  The customer service indices are derived by using the reporting of answered versus abandoned calls within these queues. Niagara Peninsula Energy Inc. exceeds the customer service quality indices of <10% of calls are abandoned within 30 seconds; the average percentage of calls abandoned within 30 seconds is less than 1% in 2018-2019. Further, the customer service quality indices of >65% of calls are answered within 30 seconds is exceeded with an average of greater than 87% in 2018-2019. Overall, between 6-7% of active customers call the utility annually.

Calls into Customer Service and Billing for 2018 are found in table below.

2018 Calls into Utility

Month	Customer Service Calls Handled	Collection Calls Handled	Billing Calls Handled	High Bills handled by phone	Total Active Customers	Total of all queues handled (customers calling into the utility)	% of Active Customers calling into utility
Jan	2,224	864	147	46	54,936	3,235	6%
February	1,754	601	160	60	54,926	2,515	5%
Mar	2,232	842	178	66	55,043	3,252	6%
April	2,471	805	121	49	55,133	3,397	6%
May	2,865	800	112	49	55,117	3,777	7%
June	2,111	929	159	50	55,105	3,199	6%
July	2739	1,754	153	58	55,086	4,646	8%
August	3,252	1,383	258	97	55,278	4,893	9%
Sept	2,392	1,037	325	154	55,304	3,754	7%
Oct	2,563	1,248	299	135	55,321	4,110	7%
Nov	2,605	783	207	74	55,430	3,595	6%
Dec	1,571	453	143	76	55,470	2,167	4%
Grand Totals	28,779	11,499	2,262	914		42,540	
Average per month	2398	958	189	76	55179	3545	6%

Calls into Customer Service and Billing for 2019 are found in table below.

2019 Calls into Utility

Month	Customer Service Calls Handled	Collection Calls Handled	Billing Calls Handled	High Bills handled by phone	Total Active Customers	Total of all queues handled (customers calling into the utility)	% of Active Customers calling into utility
Jan	2,100	847	179	49	55,403	3,126	6%
February	2,598	564	142	53	55,418	3,304	6%
Mar	1,867	697	167	66	55,422	2,731	5%
April	1,963	724	154	43	55,435	2,841	5%
May	1,939	1,402	138	43	55,476	3,479	6%
June	2,125	1,595	130	33	55,482	3,850	7%
July	2395	1,502	174	47	55,540	4,071	7%
August	2,522	1,302	268	68	55,551	4,092	7%
Sept	2,395	1,377	235	82	55,627	4,007	7%
Oct	2,472	1,535	166	45	55,747	4,173	7%
Nov	2,473	696	152	50	56,014	3,310	6%
Dec	3,829	600	350	173	56,019	4,779	9%
Grand Totals	28,678	12,841	2,255	752		43,763	
Average per month	2390	1070	188	63	55595	3647	7%

Customer Forms

To provide customers with more self- service options, several online customer facing forms have been made available via the website. Without log into the customer portal new and existing customers can access the following forms:

- Account access
- Bill Issue
- Connection Agreement
- Request for deposit waive
- Move Out

- Owner Memo
- Pre-authorized Payment Application
- Declaration of farm or multi-residence

Both interactive forms that directly interface to utility workflows, as well as, printable fillable forms are made available to the customer.

Forms are recorded based on the processing of the direct interface form workflow. Printable forms are treated as written paper requests that are emailed or mailed to our office.

Customer Forms processed in 2018

In 2018, a total of 399 forms were processed, with Pre-authorized Payment applications being the most received form.

Online Form Usage

Month 2018	Account Access	Bill Issue	Connection Agreement	Deposit Waive	Move Out	Owner Memo	Pre-authorized Payment	Declaration
January	3		4				20	
February	1		2				16	
March	2		3				29	
April	1		8				28	
May	3		1			1	12	2
June	1		9		2	1	41	
July			11		2		18	
August	3	1	5				31	
September	1		4	1	2		35	
October	1		3		1		35	
November			5		1		20	
December	1		4				24	
Grand Totals	**17**	**1**	**59**	**1**	**8**	**2**	**309**	**2**

Customer Forms processed in 2019

In 2019, a total of 705 forms were processed, with Pre-authorized Payment applications being the most received form. Both connection agreement and pre-authorized payment applications continue to increase.

Online Form Usage

Month 2019	Account Access	Bill Issue	Connection Agreement	Deposit Waive	Move Out	Owner Memo	Pre-authorized Payment	Declaration
January	3		3				35	1
February			4				15	
March			5				10	
April	3		11				28	
May			13				30	
June	1		23			3	22	
July	6		17			3	47	
August	5		18		5	1	40	
September	5		34		2		46	
October	5		33		2	1	36	
November	3	1	36	3	1	1	55	
December	3		48				38	
Grand Totals	**34**	**1**	**245**	**3**	**10**	**9**	**402**	**1**

My Account Customer Portal

Since the inception of the My Account customer portal, customer usage of the portal continues to increase by 1% per month. Currently, 38% of active customers access the customer portal. The customer portal provides 24x7 access to a customer's account where a customer can view consumption, bill history, transaction history, hourly usage by time of use, and unbilled consumption.

In 2018, My Account users defined was 17,218 customer views, representing 31% of the active customers. In 2018, 5,659 accounts requested an e-bill notification. The remaining users had view of their e-bill within the portal, just did not receive a notification at time of generation. In 2019, the number of users of My Account grew to 21,247 users, representing 38% of the active customers. In 2019, 6,720 accounts requested an e-bill notification. The remaining users had view of their e-bill within the portal, just did not receive notification at time of generation.

The customer portal has a dated user interface dating back to its inception in 2011. Customer feedback and surveys presented to Niagara Peninsula Energy Inc. that a refreshed and more secure view of customer information was needed.

The natural product upgrade that replaced the eCare v2 view is Customer Connect. Customer Connect presents a refreshed, view of customer information, with the value of a user friendly interface with the potential of building communication to our customers. Customers will be able to take more control of their utility costs and consumption. The web portal allows customers to manage bills, reduce usage, reduce the number of calls to the utility, and help the environment. The web portal's interface is simple to use with responsive forms, making it easy to use on both mobile devices and desktop browsers.

Features of the new portal that build upon the existing features of the customer portal include:

- New Service Connection set up
- Move/Transfer Premises
- Pay Now
- Request Service Call: Request of payment arrangement, move inquiry
- Display Billed Demand and Kwh Usage in View Bills for Residential and Commercial Customers
- Enhancements on existing functions including: display of bill history, transaction history, making a payment now, view of deposit

Future roadmap features of Customer Connect that align to the technology roadmap of the Customer Information System include customer notification preferences, customer direct notifications on usage, bill amounts, outage notifications, export of data to excel. The roadmap of Customer Connect in 2020 includes customer notification preferences, hourly interval usage for industrial customers and export of data to excel.

Contact Manager

One of the success factors in providing excellence in customer service is to provide communication to the customer. In a traditional customer information system, a wealth of customer information is stored. When servicing a customer, we record and are able to view customer documents, from cradle to grave of an account. New Service connection through to request to finalize a service with all of the usage and needs of the customer captured. However, as customers are aware of electricity costs and the need to control those costs continues, it becomes necessary to engage with our customers and to have information readily available in a manner and vehicle pleasing to the customer. Every customer has a different need and choice of communication. In understanding the customer need, Niagara Peninsula Energy Inc. began a multi-year development partnership with its Customer Information System to embed a customer relationship manager interface directly within the customer information system. The ability to create a customer, transact with a customer, bill and finalize a customer recording to finance system is traditional functions of the customer information system. However, an interactive manner to communicate with the customer regarding these functions is a need.

The Contact Manager component of the customer information system addresses the question of who is our customer, and to what services are they connected to. For each relation, it is defined how does that customer wants to communicate with and by whom.

For an account, dependent on function or access, a customer can define what information they want and what individual to provide information to. Further how communication is provided is defined: printed, mailed, emailed, phone (mobile, primary, secondary, etc.) The contact manager is configurable and will define to workflows within the primary functions of the customer information system. The full extent of capability of the Contact Manager includes:

- Automated workflow efficiency for new service, letter generation, billing, and collections
- Definition of Primary and Secondary Contacts
- Definition of Additional contacts
- Method of communication for each contact: email, phone, mobile, mail, sms text, social media, etc.
- Notification preferences dependent on type of communication: outage, account activity, bill, overdue notice, due date notification through to link to pay now.

Class-A Customers

In 2017, within the Billing department, a role specific to a billing representative was procedurally defined as a Class A representative. The Class A representative was an cross training initiative to work directly with the large commercial customers from identification of eligibility for the program, education of the Class A program to customers and peers, monitoring of demand and consumption, monitoring of peak periods, and working with customers to understand the costs of Global Adjustment and how to mitigate those customers in being a Class A customer. Specific customer engagement activities are planned annually at time of start of program in April. One session is held in April and another in June. Industry stakeholders, Engineering and Conservation peers are included within the session. This engagement begins as an in person session offered to all eligible customers. The session reviews the Class A program, education on how an industrial commercial customer is billed, how usage and demand can be monitored, and how peak periods are tracked. The connection with Class A representatives are made and follow up one on one session(s) either by phone, email, or in person meetings with the customer is scheduled. At times in 2018 and 2019, Niagara Peninsula Energy Inc. was invited to the commercial customers place of business to conduct staff training and education of the Class A program. This session was conducted by Billing Representatives. For each session, conservation was included to expand on what information and programs that the customer could take advantage. Serving the class A customer has become a specialty within Billing that customers have come to look for and appreciate as monthly reviews and touch points are opportunities for outreach to customers.

Conclusion

Within the technology roadmap, as well as, review of the role of the Billing Representative, customer engagement and the ability and functionality to meet the needs of the customer is functionality that will be inherent in the applications and processes that we put into place.

Appendix 1-22

List of Customer engagement events from 2017 to 2019

EVENT NAME	DATE/ TIME	CITY/ LOCATION	# OF PEOPLE AT EVENT	# OF PEOPLE ENGAGED	TYPE OF EVENT/ OUR PARTICIPATION	GENERAL FEEL i.e. concerned, friendly	FOCUS OF BOOTH	BOOTH ITEMS	IMPROVEMENT IDEAS/ GENERAL COMMENTS
Deal Days Retailer Event	Oct. 13, 2017 12p.m. - 6p.m.	Niagara Falls/Canadian Tire	200-300	150+	Booth set up during coupon event to promote energy efficient items on sale	Positive, people appreciative of sales, good questions asked about efficiency, home upgrades discussed	Energy efficiency, home upgrades, LED technology, how to lower your energy bill, e-bill contest	Flashlights, pencils, cards, e-bill flyers, conservation handbooks	Confirm limits on products as there was confusion, pack lots of promo items as they went quick
Deal Days Retailer Event	Oct. 14, 2017 10a.m. - 4p.m.	Niagara Falls/Lowes	300-400	200+	Booth set up during coupon event to promote energy efficient items on sale	Positive, people appreciative of sales, good questions asked about efficiency, home upgrades discussed	Energy efficiency, home upgrades, LED technology, how to lower your energy bill, e-bill contest	Flashlights, pencils, cards, e-bill flyers, conservation handbooks	Ask to be near the door to get the most traffic, confirm limits on products as there was confusion, pack lots of promo items as they went quick
Deal Days Retailer Event	Oct. 21, 2017 10a.m. - 4p.m.	Niagara Falls/Home Depot	300-400	150+	Booth set up during coupon event to promote energy efficient items on sale	Positive, people appreciative of sales, good questions asked about efficiency, home upgrades discussed	Energy efficiency, home upgrades, LED technology, how to lower your energy bill, e-bill contest	Flashlights, pencils, cards, e-bill flyers, conservation handbooks	Ask to be near the door to get the most traffic instead of down the aisle like we were
Wellspring Winter Walk	Feb. 17, 2018 9a.m. - 12p.m.	Pelham/Penn Financial	50	50+	Community walk to raise funds for Wellspring Niagara/we were sponsor and gave opening speech	Friendly event, people receptive of our speech, people glad that we sponsored event	N/A	N/A	NPEI wasn't the main focus of event, some conversations had with individuals, there to show us getting out in community and giving back
Agripump Program Launch Event	March 23, 2018 9a.m. - 12p.m.	Lincoln/Hendriks Greenhouse	40	40+	Launch event for new program by NPEI and H1, media, utilities and farm owners in attendance	Gernerally friendly and receptive crowd, people wanted to hear about program and details	N/A	N/A	Launch went well, representatives from NPEI and H1 spoke
Deal Days Retailer Event	April 7, 2018 10a.m. - 4p.m.	Niagara Falls/Canadian Tire	200-300	150+	Booth set up during coupon event to promote energy efficient items on sale	Positive, people appreciative of sales, good questions asked about efficiency, home upgrades discussed	Energy efficiency, home upgrades, LED technology, how to lower your energy bill	Flashlights, pencils, cards, conservation handbooks	Confirm limits on products as there was confusion, pack lots of promo items as they went quick
Deal Days Retailer Event	April 14, 2018 10a.m. - 4p.m.	Niagara Falls/Home Depot	300-400	150+	Booth set up during coupon event to promote energy efficient items on sale	Positive, people appreciative of sales, good questions asked about efficiency, home upgrades discussed	Energy efficiency, home upgrades, LED technology, how to lower your energy bill	Flashlights, pencils, cards, conservation handbooks	Ask to be near the door to get the most traffic, confirm limits on products as there was confusion, pack lots of promo items as they went quick
Chippawa Home and Garden Show	May 4 - 6, 2018 10a.m. - 6p.m.	Chippawa/Chippawa Arena	600-800	300+	Booth set up during home show to promote NPEI conservation programs, services, answer questions from customers	People were nice, lots stopped at the booth, interested in learning about some of the programs, enjoyed the free swag	Conservation programs for businesses, energy efficiency for homes, Save on Energy rebates	Flashlights, water bottles, pencils, cards, conservation handbooks, conservation program flyers,	
West Lincoln Touch A Truck	May 23, 2018 10a.m. - 1p.m.	West Licoln/West Lincoln Town Hall	100-200	150+ (Kids)	Booth set up, mainly kids on a field trip, we teach them about what linemen do and about the trucks	Kids were interested and excited to see the truck, most were happy to learn about everything we told them, excited for free stuff, everyone in good mood	Electrical safety, what linemen do, how the trucks work, home conservation tactics	Conservation handbooks, flashlights, pencils, cards, colouring sheets	Good event, as it's mostly kids there isn't a lot of meaningful conversations happening, but its fun to watch the kids and the linemen interact and to teach them stuff

EVENT NAME	DATE/ TIME	CITY/ LOCATION	# OF PEOPLE AT EVENT	# OF PEOPLE ENGAGED	TYPE OF EVENT/ OUR PARTICIPATION	GENERAL FEEL i.e. concerned, friendly	FOCUS OF BOOTH	BOOTH ITEMS	IMPROVEMENT IDEAS/ GENERAL COMMENTS
Niagara Falls Touch A Truck	May 26, 2018 10a.m. - 2p.m.	Niagara Falls/Gale Centre	200-250	150+	Booth set up, kids and parents would come and talk about the trucks, what linemen do, electrical safety	Kids were interested and excited to see the truck, most were happy to learn about everything we told them, excited for free stuff, everyone in good mood	Electrical safety, what linemen do, how the trucks work, home conservation tactics	Conservation handbooks, flashlights, pencils, cards, colouring sheets	Good event, people aren't super interested in talking about conservation programs or energy efficiency though, more about the linemen today and electrical safety, how the trucks work
Lincoln Touch A Truck	June 2, 2018 10a.m. - 2p.m.	Lincoln/Fleming Centre	200-300	150	Booth set up, kids and parents would come and talk about the trucks, what linemen do, electrical safety	Kids were interested and excited to see the truck, most were happy to learn about everything we told them, excited for free stuff, everyone in good mood	Electrical safety, what linemen do, how the trucks work, home conservation tactics	Conservation handbooks, flashlights, pencils, cards, colouring sheets	Good event, people aren't super interested in talking about conservation programs or energy efficiency though, more about the linemen today and electrical safety, how the trucks work
GNCC Business Achievement Awards	June 13, 2018 5p.m. - 9p.m.	St. Catharines/Holiday Inn Conference Centre	250	250	Gala Dinner to celebrate small business achievements, we sponsored an award that we presented on stage	Very positive event	N/A	N/A	We are not the main focus of this event and no connections or meaningful conversations were had, just a quick award presentation that shows that we support local businesses
West Niagara Fair	September 7-9, 2018 5p.m.-9p.m. 11a.m.-6p.m.	West Lincoln/West Niagara Agricultural Centre and Fairgrounds	400-600	250	Booth set up at fair to disucss energy efficiency, conservation programs, do general outreach	Pretty positive event, some negative because of unreliability of system in West Lincoln, good engagement with customers	Conservation programs for businesses, energy efficiency for homes, Save on Energy rebates	Conservation handbooks, flashlights, pencils, cards, colouring sheets, business conservation program flyers	A lot of manhours required for event, good to get out in that service territory though, some negative comments about billing concerns that could have been communicated better
Deal Days Retailer Event	Oct. 6, 2018 10a.m. - 4p.m.	Niagara Falls/Home Depot	300-400	150+	Booth set up during coupon event to promote energy efficient items on sale	Positive, people appreciative of sales, good questions asked about efficiency, home upgrades discussed	Energy efficiency, home upgrades, LED technology, how to lower your energy bill, e-bill contest	Flashlights, pencils, cards, e-bill flyers, conservation handbooks	Ask to be near the door to get the most traffic instead of down the aisle like we were
Deal Days Retailer Event	Oct. 27, 2018 10a.m. - 4p.m.	Niagara Falls/Canadian Tire	200-300	100+	Booth set up during coupon event to promote energy efficient items on sale	Positive, people appreciative of sales, good questions asked about efficiency, home upgrades discussed	Energy efficiency, home upgrades, LED technology, how to lower your energy bill, e-bill contest	Flashlights, pencils, cards, e-bill flyers, conservation handbooks, e-bill flyers	Confirm limits on products as there was confusion, pack lots of promo items as they went quick
Deal Days Retailer Event	Nov. 3 2018 10a.m. - 4p.m.	Niagara Falls/Lowes	300-400	150+	Booth set up during coupon event to promote energy efficient items on sale	Positive, people appreciative of sales, good questions asked about efficiency, home upgrades discussed	Energy efficiency, home upgrades, LED technology, how to lower your energy bill, e-bill contest	Flashlights, pencils, cards, e-bill flyers, conservation handbooks, e-bill flyers	Confirm limits on products as there was confusion, pack lots of promo items as they went quick
Wellspring Winter Walk	Feb. 16, 2018 9a.m. - 12p.m.	Pelham/Wellspring Niagara	50	50+	Community walk to raise funds for Wellspring Niagara/we were sponsor and gave opening speech	Friendly event, people receptive of our speech, people glad that we sponsored event	N/A	N/A	NPEI wasn't the main focus of event, some conversations had with individuals, there to show us getting out in community and giving back

EVENT NAME	DATE/ TIME	CITY/ LOCATION	# OF PEOPLE AT EVENT	# OF PEOPLE ENGAGED	TYPE OF EVENT/ OUR PARTICIPATION	GENERAL FEEL i.e. concerned, friendly	FOCUS OF BOOTH	BOOTH ITEMS	IMPROVEMENT IDEAS/ GENERAL COMMENTS
West Lincoln Touch A Truck	May 16, 2019 9a.m. - 2p.m.	West Lincoln/West Niagara Agricultural Centre and Fairgrounds	100-200	150+ (Kids)	Booth set up, mainly kids on a field trip, we teach them about what linemen do and about the trucks	Kids were interested and excited to see the truck, most were happy to learn about everything we told them, excited for free stuff, everyone in good mood	Electrical safety, what linemen do, how the trucks work, home conservation tactics	Conservation handbooks, flashlights, pencils, cards, colouring sheets	Good event, as it's mostly kids there isn't a lot of meaningful conversations happening, but its fun to watch the kids and the linemen interact and to teach them stuff
Lincoln Touch A Truck	May 25, 2019 9a.m. - 2p.m.	Lincoln/Fleming Centre	200-300	150+	Booth set up, kids and parents would come and talk about the trucks, what linemen do, electrical safety	Kids were interested and excited to see the truck, most were happy to learn about everything we told them, excited for free stuff, everyone in good mood	Electrical safety, what linemen do, how the trucks work, home conservation tactics	Conservation handbooks, flashlights, pencils, cards, colouring sheets	Good event, people aren't super interested in talking about conservation programs or energy efficiency though, more about the linemen today and electrical safety, how the trucks work
Club Italia Picnic	July 14 ,2019 12p.m. - 5p.m.	Niagara Falls/Club Italia	400	75+	Booth set up during community picnic,				

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Social Media posting example

Social Media

Niagara Peninsula Energy Inc.
Published by Ethan Fahey

We want to hear from you! Have your input and help us shape our five-year plan. You could even win a $500 bill-creditat NPEI. Take the survey at www.npei.ca/feedback

Niagara Peninsula Energy Inc.
Published by Ethan Fahey

Your opinion could be worth $500! We need your input on plans that will affect your electricity service and the price you pay. Fill out the survey at www.npei.ca/feedback

Niagara Peninsula Energy Inc.
Published by Ethan Fahey

We're planning for our future and we want your help! This is your opportunity to provide input for our 5-year plan. Complete the survey at www.npei.ca/feedback

E-Blast Emails

NPEI is currently preparing our Distribution System Plan and we want our customers' help to shape our plan for the next five years! This is your opportunity to provide valuable input and ensure our decisions are aligned with your priorities. By completing our survey, you'll help us make positive changes in our community and keep you in the now. You could even win a $500 bill-credit at NPEI! Fill out the survey now at www.npei.ca/feedback

Appendix 1-24

Social Media Report December 2019

Social Media Report

" We Want your Feedback"

Prepared by

JEFF GALLUCCI

POSTMEDIA SOLUTIONS

Social Media Creative

POSTMEDIA

Niagara Peninsula Energy Inc. Digital Advertising Report

Dec 2, 2019 - Dec 2, 2019

Social Media Advertising Results

Results Last Refreshed: Jan 5, 2020, 11:57 PM

Showing Results from: Dec 2, 2019 **to** Dec 21, 2019

68,165
Impressions
Number of times your ad has been shown.

1,592
Social Media Clicks
Number of times your social media ads have been clicked.

2.34%
Click & Engagement Rate
from 68,165 impressions

Appendix 1-25

NPEI's Customer Engagement Final Report

INNOVATIVE
RESEARCH GROUP

Customer Engagement

2021-2025 Rate Application

January 2020

Prepared for:

Niagara Peninsula Energy Inc.
7447 Pin Oak Drive
Niagara Falls, ON
L2E 6S9

Customer Engagement Overview

January 2020

Confidentiality

Acknowledgement

This Overview has been prepared by Innovative Research Group Inc. ("INNOVATIVE") for Niagara Peninsula Energy Inc. The conclusions drawn, and opinions expressed are those of the authors.

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INNOVATIVE
RESEARCH GROUP

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Introduction

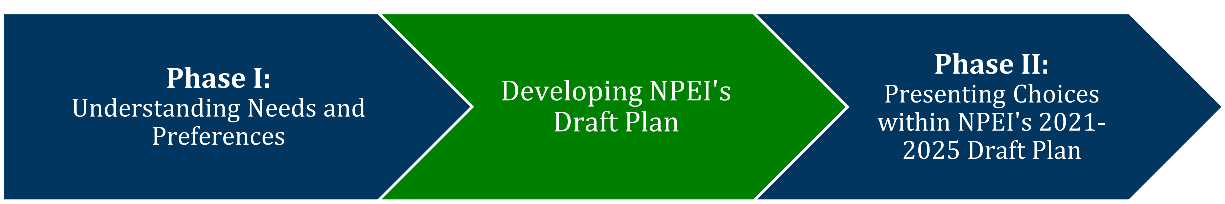
In May 2019, Innovative Research Group Inc. (INNOVATIVE) was engaged by Niagara Peninsula Energy to assist in meeting the utility's customer engagement commitments under the Renewed Regulatory Framework for Electricity Distributors (RRFE).

Niagara Peninsula Energy is in the process of developing its 2021-2025 rate application and set out to gather meaningful feedback from its customers, specifically when it comes to their needs, the outcomes important to them, and their preferences regarding the pacing and prioritization of specific investments.

Between June and December 2019, Niagara Peninsula Energy gathered feedback from more than 3,000 residential, small business and commercial customers through its customer engagement efforts - in context, Niagara Peninsula Energy, through INNOVATIVE, engaged with nearly 6% of its entire customer base.

Throughout this customer engagement, a concerted effort was made to ensure that all customers – regardless of where they live or operate, or how much electricity they use - had an equal opportunity to participate, whether through voluntary or random sampling. In order to facilitate the collection of this robust feedback, INNOVATIVE and NPEI developed a two-phased approach which was both iterative and responsive at each stage of feedback.

Undertaking a two-phased approach also enabled NPEI a clear opportunity to demonstrate how customer feedback collected in Phase I was incorporated into the utility's draft plans, and will enable them to clearly respond to actionable feedback gathered in Phase II. Incorporating customer feedback into NPEI's plans was a key objective of this customer engagement, and this two-phased approach helped facilitate its achievement.



This document contains the results of both phases of customer engagement, with a focus on the generalizable results of the representative sample from Phase II.

Customer Engagement Key Findings

Phase I: Understanding Needs and Preferences

The first phase of NPEI's 2019 customer engagement look place between **June and July 2019** with a series of focus groups, and telephone and online surveys.

The purpose of this initial phase of engagement was to provide NPEI planners with input on customers' needs and preferences as they relate to the outcomes and goals that the utility should focus on over the 2021-2025 period; as well as develop a detailed understanding of the differences between customers with known email addresses (email sample) and the broader customer base (telephone sample).

This initial phase of engagement was conducted at the beginning of NPEI's planning cycle in order to ensure that the draft plan distinctly took into consideration the views of customers.

In June 2019, an initial round of four exploratory focus groups were conducted amongst residential and small business customers in both Niagara Falls and West Lincoln. One primary objective of these groups was to obtain insights into what customers expect of NPEI, what are their priorities, both in context of valued outcomes, and the investment choices impacting customers that the utility will need to make.

NPEI's customer engagement was an iterative process, wherein each phase and activity informed the next. The results of these exploratory focus groups (see **Appendix 1.0** for summary), played an important role in informing the questions that were asked in a subsequent series of telephone and online surveys.

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 needs, preferences and expectations learned through the utility's customer engagement activities*."[1] This section provides an overview of customer needs, preferences and expectations as gathered through parallel online and telephone surveys. Full results can be found in **Appendix 2.0**.

Customer Needs

Needs questions focus on understanding the gap between the services and experience customers want and the services and experience customers are receiving.

In the initial exploratory focus groups, participants noted that they were satisfied with the services they receive from NPEI, including both customer service and, the level of reliability they experience.

[1] Handbook for Utility Rate Applications, p. 12 (October 13, 2016)

Overall Satisfaction with Niagara Peninsula Energy

The Phase I surveys confirmed that most residential and small business customers are satisfied with the level of service that NPEI provides.

Phase I Telephone Reference Survey	Residential	Small Business
Satisfied	89%	87%
Dissatisfied	6%	3%

What can NPEI do to improve services?

Looking beyond topline customer satisfaction, to uncover whether there is a gap between the services and experience customers want and what they are receiving, we asked what NPEI could do, if anything, to improve services.

In the exploratory focus groups, many customers felt that the price of electricity was the central area where NPEI could improve service. That said, very few had an initial understanding of NPEI's role in the electricity system, including the portion of their bill that is remitted to the utility. Additionally, some customers felt that there was a lack of customer education regarding the system as a whole, with particular emphasis on helping customers reduce their electricity bills.

In the Phase I telephone survey, the majority of residential and small business customers noted that they either didn't know how services could improved or expressed that there was nothing in particular that the utility could do to improve service. Similar to the focus groups, about 1-in-5 customers noted that the NPEI could improve services by reducing rates.

Phase I Telephone Reference Survey	Residential	Small Business
1st	*Don't know* (30%)	*Don't know* (35%)
2nd	*None* (24%)	*Lower/Reduce rates* (21%)
3rd	*Lower/Reduce rates* (22%)	*None* (15%)

The combination of high levels of satisfaction, as well as a majority of customers not indicating how NPEI can improve services, leads to conclusion that the utility is meeting current customer needs.

Customer Preferences

Preference questions focus on customer views on the outcomes the utility should focus on, priorities among those outcomes, and trade-offs as illustrated by choices on specific programs or the pacing and prioritization of investments.

One of the objectives of the exploratory focus groups was to develop a list of outcomes/goals that NPEI should focus on in its upcoming rate application. Upon building this list with qualitative customer feedback, the Phase I surveys focused on confirming whether this list was exhaustive, in addition to quantifying customer preferences to the broader customer base.

This list featured seven outcomes /goals:

- *Ensuring reliable electrical service*

- *Delivering electricity at reasonable distribution rates*
- *Providing quality customer service and enhanced communications*
- *Proactively replacing aging infrastructure that is beyond its useful life*
- *Finding internal efficiencies and ways to find cost savings*
- *Upgrading the electrical system to better respond to and withstand the impact of adverse weather and climate change*
- *Providing tools and services that allow customers to better manage their electricity usage*

Based on the generalizable feedback from the Phase I telephone surveys, customers don't expect NPEI to just focus on one outcome. In fact, the majority of both residential and small business customers feel that almost all of the identified outcomes are *extremely important* (with the exception of providing tools to better manage electricity).

What outcomes do customers prioritize?

Among competing outcomes, *price*, *reliability*, and *finding internal cost efficiencies* are the top three priorities for both residential and small business customers. When ranked relative to other priorities, NPEI customers see price as the top outcome that the utility should focus on.

Telephone Survey	Phase I Telephone Reference Survey	
	Residential	Small Business
Top Priority	*Delivering electricity at reasonable distribution rates*	*Delivering electricity at reasonable distribution rates*
2nd Priority	*Ensuring reliable electrical service*	*Ensuring reliable electrical service*
3rd Priority	*Finding internal efficiencies and ways to find cost savings*	*Finding internal efficiencies and ways to find cost savings*

What reliability outcomes do customers prioritize?

Beyond the priority of ensuring reliability electrical service, customers were asked which aspect of the reliability outcome NPEI should focus on. *Reducing the overall number of outages*, the *overall length of outages*, and *improving restoration times* are the top three priorities for both rate classes.

Telephone Survey	Phase I Telephone Reference Survey	
	Residential	Small Business
Top Priority	*Reducing the overall <u>number</u> of outages*	*Reducing the overall <u>number</u> of outages*
2nd Priority	*Reducing the overall <u>length</u> of outages*	*Reducing the overall <u>length</u> of outages*
3rd Priority	*Reducing the length of time to restore power during extreme weather events*	*Reducing the length of time to restore power during extreme weather events*

What investment trade-offs do customers value most?

Beyond developing an understanding of the needs and outcomes that customers prioritize, the Phase I surveys also explored general trade-offs between several types of investments and cost.

These questions were intended to provide preliminary input for NPEI in putting together their initial draft plan.

In fact, the results from these surveys were summarized in the *"Customer Engagement: Needs and Preferences Planning Placemat"* (see **Appendix 3.0**) The *Planning Placemat* provided a high-level summary of the findings from the Phase I surveys, including both needs and preferences. It was shared with NPEI planners and helped ensure that customer feedback was brought into the planning process in the early stages.

Replacing Aging Infrastructure (System Renewal)

While keeping prices at a reasonable and affordable level is an important priority for customers, the majority feel that investing in the grid to maintain reliability, is preferable to deferring investments to keep bills low.

Phase I Telephone Reference Survey	Residential	Small Business
Invest what it takes to maintain reliability	62%	64%
Defer investments to lessen bill impacts	26%	19%

Proactive Investments in Grid Modernization (New Technology)

The majority of residential and small business customers are willing to consider paying more to invest in maintaining reliability, equipping staff with equipment and IT systems. Knowing that it could eventually save money, they supported proactively investing in system capacity, and modernizing the grid.

Further, the majority of customers support proactive investment in both system capacity and grid modernization. Relative to other trade-offs, support for investment in system capacity is least intense.

Phase I Telephone Reference Survey	Residential	Small Business
Make proactive investments	62%	55%
Make investment prioritizing lowest cost	25%	21%

Using the input from the Phase I customer engagement, NPEI planners developed a draft plan that included an estimated baseline cost and identified a number of investment areas where pacing could be accelerated, or slowed down, in order to align with customer needs and expectations.

The Phase II customer engagement focused on presenting these investment trade-offs to customers and gathering feedback on NPEI's draft plan. The next section will summarize the findings from these activities.

Phase II: Introduction

The second phase of NPEI's customer engagement focused on customer preferences on pacing and balancing outcomes. In order to obtain this feedback, an online "workbook" was deployed to all customers with an email address on file, as well as promoted through a generic link on NPEI's website and social media platforms.

This workbook was designed to both educate customers on NPEI's role in the electricity system and its draft business plans, as well as to gather feedback on trade-offs between seven specific investments.

Prior to developing this customer engagement workbook, NPEI staff used customer feedback, collected throughout the Phase I engagement, to help align its 2021 to 2025 investment plan with customer expectations.

Phase II of the engagement focused on two core objectives:

1. Confirming customers' needs, preferences and priorities identified in Phase I; and,
2. Soliciting customer feedback on the content of NPEI's draft plan, including customer preferences towards particular capital investments where trade-offs on pacing exist.

The seven specific investments were presented in the form of trade-off questions. In most cases, these investments were presented as a choice between several approaches – the pace of investment included in NPEI's draft plan; an *accelerated pace*; or a *reduced pace*. The individual bill impact (customized by rate class) of each approach was presented alongside the choice.

Beyond presenting bill impacts for individual approaches to pacing investments, the workbook – which can be found in its entirety in **Appendix 7.0** – allowed customers to review the cumulative impact of their choices and adjust their responses using a dynamic "bill calculator". Customers were able to change their responses until they felt they had found the right pace of investments and estimated rate impact.

The following section summarizes customer feedback from the online workbook which was sent to all residential, small business and GS >50 kW customers with an email on file.

Phase II: Key Findings

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 pace of investment.

In fact, when it comes to *underground cable replacement, overhead pole replacement*, and *overhead transformer replacement*, many customers from each rate class, support an accelerated investment approach. These three investments consistently received the strongest levels of support.

The results below demonstrate that regarding *underground cable replacement, overhead pole replacement*, and *overhead transformer replacement,* most customers support an approach that falls somewhere between what is included in the draft plan and a more accelerated pace of investment.

Underground Cable Replacement

Relative to other investment options presented to customers, underground cable replacements received some of the highest levels of support for an accelerated approach. Almost equal proportions of residential and small business customers support an accelerated approach, while GS >50 kW customers are more divided between what is currently included in the draft plan and a more proactive investment approach.

Underground Cable Replacement *n-size for sample sizes <50*	**Representative Workbook**			**Voluntary**
	Residential	Small Bus.	GS >50 kW	Low Volume
Further Accelerated Pace	29%	31%	2/32	25%
Accelerated Pace	36%	37%	14/32	36%
Included in Draft Plan	35%	32%	16/32	38%

Despite a correlation between whether your electricity bill has a significant impact on household finances and the likelihood of supporting a move accelerated approach to underground cable replacement, a majority of all respondents either support the approach in the draft plan or an accelerated pace. In fact, a majority of residential customers who say their bill has a *significant* impact on their households' finances support either the current or an accelerated approach.

Underground Cable Replacement *Residential Customers*	**Bill Impact on Finances**		
	Significant Impact	Impact	No Impact
Accelerated Pace	27%	24%	34%
Included in Draft Plan	31%	39%	37%
Slower Pace	43%	37%	29%

Overhead Pole Replacement

Overhead Pole Replacement *n-size for sample sizes <50*	**Representative Workbook**			**Voluntary**
	Residential	Small Bus.	GS >50 kW	Low Volume
Accelerated Pace	47%	56%	10/32	45%
Included in Draft Plan	35%	31%	15/32	33%
Slower Pace	18%	13%	7/32	22%

Overhead Transformer Replacement

Overhead Transformer Replacement *n-size for sample sizes <50*	Representative Workbook			Voluntary
	Residential	Small Bus.	GS >50 kW	Low Volume
Accelerated Pace	47%	53%	14/32	45%
Included in Draft Plan	36%	28%	12/32	33%
Slower Pace	17%	19%	6/32	23%

Grid Modernization

With regards to investments in Supervisory Control and Data Acquisition (SCADA) systems, NPEI customers are almost evenly divided. Nearly equal proportions of residential, small business and GS >50 kW customers support either the approach included in the draft plan, or an accelerated one that would see the number of devices installed doubled over the next five-year period.

Grid Modernization *n-size for sample sizes <50*	Representative Workbook			Voluntary
	Residential	Small Bus.	GS >50 kW	Low Volume
Accelerated Pace	41%	41%	12/32	33%
Included in Draft Plan	44%	41%	14/32	46%
Slower Pace	14%	18%	6/32	20%

Despite strong overall support for an accelerated approach to installing SCADA systems, there is a high degree of correlation between bill impact on finances and one's likelihood to support higher levels of spending. In fact, more "vulnerable" residential customers are more likely to support a slower pace than an accelerated pace of investment.

Grid Modernization *Residential Customers*	Bill Impact on Finances		
	Significant Impact	Impact	No Impact
Accelerated Pace	26%	38%	50%
Included in Draft Plan	38%	47%	44%
Slower Pace	36%	15%	6%

The investments which received the lowest levels of support relative to the other options presented included: *Converting outdated underground kiosk transformers*, *subdivision underground rehabilitation*, and *overhead rebuilds*.

Converting Outdated Underground Kiosk Transformers

Converting underground kiosk transformers was the one investment option that was presented without an accelerated approach. The pace included in the draft plan, which was in line with historic rates of replacement, was supported by the majority of customers in each rate class.

That said, nearly 4-in-10 residential and small business customers expressed their support for an investment pace below what is included in the draft plan. This propensity to support a slower investment pace was the lowest amongst the seven investment options presented to customers.

Kiosk Transformers *n-size for sample sizes <50*	**Representative Workbook**			**Voluntary**
	Residential	Small Bus.	GS >50 kW	Low Volume
Included in Draft Plan	56%	60%	21/32	45%
Reduced Pace	30%	23%	4/32	39%
Slower Pace	14%	17%	7/32	17%

When it comes to replacing kiosk transformers, customers who's bill significantly impacts their finances hold much different views than other customers. In fact, a strong majority of these customers say that NPEI should take a slower approach to replacing this equipment compared to what it currently being proposed.

Kiosk Transformers *Residential Customers*	**Bill Impact on Finances**		
	Significant Impact	Impact	No Impact
Included in Draft Plan	27%	53%	69%
Reduced Pace	37%	33%	25%
Slower Pace	36%	14%	6%

Relative to the other investments presented to customers, *subdivision underground rehabilitation*, and *overhead rebuilds* saw the weakest support for an accelerated investment approach. About 3-in-10 residential and small business customers supported an accelerated pace, while a plurality would prefer what is currently included in the draft plan.

Subdivision Underground Rehabilitation

In fact, a plurality (14 of 32) GS >50 kW customers supported a slower pace of subdivision underground rehabilitation, provided that they would not be directly impacted by such investments.

Subdivision Underground Rehabilitation *n-size for sample sizes <50*	**Representative Workbook**			**Voluntary**
	Residential	Small Bus.	GS >50 kW	Low Volume
Accelerated Pace	33%	34%	6/32	31%
Included in Draft Plan	45%	52%	12/32	45%
Slower Pace	22%	14%	14/32	24%

Overhead Rebuilds

Similarly, almost equal proportions of customers in all rate classes offer the same levels of support for *overhead rebuilds*.

Overhead Rebuilds *n-size for sample sizes <50*	**Representative Workbook**			**Voluntary**
	Residential	Small Bus.	GS >50 kW	Low Volume
Accelerated Pace	32%	35%	5/32	26%
Included in Draft Plan	50%	45%	19/32	52%
Slower Pace	19%	20%	8/32	23%

In its upcoming application, NPEI is considering a rate design change for GS > 50 kW customers. These customers were presented three options and asked to provide feedback – the status quo fixed-variable split, and two options with a higher fixed rate, including what they are proposing in the draft plan.

Potential changes to fixed versus variable distribution rates

In total, 20 of 32 GS > 50 kW customers support the rate design included in the draft plan, with 11 of 32 supporting the status quo. Based on this feedback, there does not appear to be a propensity for customers to support a higher fixed distribution charge than what is currently being proposed.

Online Workbook	GS >50 kW
Status Quo (15% fixed; 85% variable)	11/32
Included in Draft Plan (21% fixed; 79% variable)	20/32
Higher Fixed Distribution Charge (33% fixed; 66% variable)	1/32

Cumulative Bill Impacts

After providing their preferences on the seven investments presented in the workbook, customers had the opportunity to review the cumulative impact of their choices and adjust their responses using a dynamic "bill calculator".

It was made clear to participants that these impacts were *in addition to* what is included in the draft plan, for residential customers, this was a 2.5% increase over 5-years. If customers selected the *"Included in the Draft Plan"* option for each investment, the rate impact was zero. For residential customers, the range of potential impacts was +$0.23 if they selected all of the most accelerated approaches, and -$0.10 is they consistently selected the slowest approaches.

On average, customers did not make significant changes to their initial responses. In fact, for both residential and small business customers, the average rate increase rose by $0.01 after customers had the opportunity to adjust their responses. Customers on average were more likely to select the accelerated pace of investment once given the opportunity to see the cumulative impact of their choices. It should be noted, however, that these changes cannot be deemed statistically significant, essentially meaning that there was no change from initial to final responses.

Cumulative Bill Impacts	Residential	Small Bus.
Average Initial ($)	$0.08	$0.16
Average Final ($)	$0.09	$0.17

Assessing NPEI's Draft 2021-2025 plan

Overall, customers in all rate classes are prepared to pay for the level of investment included in NPEI's draft plan. In fact, customers are between two and three times as likely to support a more accelerated investment approach compared to a slower approach that keeps rates below what it currently proposed.

Again, when it comes to *overhead pole replacement*, *overhead transformer replacement*, and *underground cable replacement,* most customers support an approach that falls somewhere between what is included in the draft plan and a more accelerated pace of investment.

Assessing NPEI's Draft Plan *n-size for sample sizes <50*	Representative Workbook			Voluntary
	Residential	Small Bus.	GS >50 kW	Low Volume
Improve service, even if it exceeds proposed increase	33%	26%	4/32	27%
Maintain proposed increase	49%	57%	20/32	45%
Keep increases below proposed	11%	13%	6/32	18%
Other	2%	1%	1/32	2%
Don't know	5%	2%	1/32	9%

Specific attention has been paid to how those whose electricity bill has a significant impact on their households' (or business') finances opinions vary from the broader customer base. Reflecting their financial capacity, those who agree that their electricity bill has a *significant impact* on their household's finances are less supportive of investments than the average customer but still generally support NPEI's draft plan and the associated impacts. Still, it is important to note that about 3-in-10 of these more "vulnerable" customers believe that NPEI should keep increases below what is currently proposed.

Assessing NPEI's Draft Plan *Residential Customers*	Bill Impact on Finances		
	Significant impact	Some Impact	No Impact
Improve service	17%	27%	43%
Maintain increase	36%	55%	50%
Keep increases below	29%	13%	3%

Across NPEI's service territory, there is limited regional variance regarding support for the utility's draft plan and associated impacts. As shown below, customers located in Niagara Falls/Pelham are more likely to support a more accelerated approach to investment, even if it could result in higher rate impacts.

Assessing NPEI's Draft Plan *Residential Customers*	Regional Segmentation		
	Niagara Falls/Pelham	Lincoln	West Lincoln
Improve service	43%	38%	38%
Maintain increase	41%	52%	50%
Keep increases below	16%	10%	12%

Phase II: Workbook Diagnostics

A principle element of utility rate applications, as outlined by the OEB, is the ongoing nature of customer engagement. The OEB states: *"Planning is an ongoing utility activity, not just something that is done in preparation for a rate application. Likewise, customer engagement to inform utility planning must also be an ongoing activity."*[2]

Considering the ongoing nature of customer engagement, it is important to understand whether customers had a favourable impression of the utility's efforts to gather feedback on its plans, and if there are areas that could be improved upon for future engagements.

Overall Impression of Workbook and Volume of Information

Overall, the vast majority of customers who completed the online workbook had a favourable impression. When asked whether there was anything that was left unanswered after completing the workbook, almost all customers said there were "none".

Online Workbook *n-size for sample sizes <50*	Representative Workbook			Voluntary
	Residential	Small Bus.	GS >50 kW	Low Volume
Favourable	88%	96%	28/32	84%
Unfavourable	7%	1%	3/32	9%

Likewise, an almost equal proportion of customers felt that the online workbook provided *"just the right amount of information"*, with only 9% of low-volume customers saying, *"too little"*.

Online Workbook *n-size for sample sizes <50*	Representative Workbook			Voluntary
	Residential	Small Bus.	GS >50 kW	Low Volume
Too little	5%	5%	5/32	10%
Just the right amount	86%	87%	23/32	80%
Too much	9%	9%	4/32	10%

[2] Handbook for Utility Rate Applications, p. 12 (October 13, 2016)

Customer Engagement Approach

As mentioned earlier, NPEI and INNOVATIVE developed and executed a two-phased customer engagement approach. This approach created multiple opportunities for customers to provide feedback, and provided NPEI with multiple opportunities to consider and incorporate customer feedback as part of the planning process.

While detailed methodologies are contained within each individual report as appendices, this section will highlight some of the key methodological elements of NPEI's 2021-2025 customer engagement approach.

Summary of NPEI's Customer Engagement Results – Phase I and Phase II

Customer Group	Methodology	Unweighted Sample Size	Field Dates
Residential	Telephone	n=505	July 9 – 26, 2019
Small Business	Telephone	n=87	July 9 – 26, 2019
Residential	Online	n=939	July 12 – 29, 2019
Small Business	Online	n=71	July 12 – 29, 2019
Phase 1 Total Customers Engaged: n=1,602			
Residential	Online Voluntary	n=224	December 2 – 17, 2019
Small Business	Online Voluntary	n=9	December 2 – 17, 2019
Residential	Online Representative	n=1,264	November 21 – December 17, 2019
Small Business	Online Representative	n=56	November 21 – December 17, 2019
Commercial (GS > 50 kW)	Online Representative	n=32	December 3 – 18, 2019
Phase 2 Total Customers Engaged: n=1,585			
Total Customers Engaged as Part of NPEI's 2019 Customer Engagement: 3,187			

Phase I Approach

In Phase I, Niagara Peninsula Energy and INNOVATIVE set out to understand two core elements about its customers.

First, as discussed in detail throughout this report, a key objective of Phase I was to develop an understanding of NPEI customers' needs and preferences. Feedback from this phase helped NPEI planners and engineers inform the design of the utility's draft investment plan, which was shared in draft, with customers in Phase II.

Second, in order to move to a more online-centric approach to engagement, INNOVATIVE needed to develop a detailed understanding of the differences between customers with known email addresses (email sample) and the broader customer base (telephone sample).

INNOVATIVE was able to confidently ascertain the potential differences between these two sample groups by first fielding two parallel online and telephone surveys (see **Appendix 2.0** for details) and then undertaking a rigorous "sample validation" process.

This sample validation process included comparing known variables (i.e. region and electricity consumption) across the overall population to the sample of that of the population with email addresses. Through this process, INNOVATIVE was able to conclude that no "group" is substantially underrepresented in the email sample.

Email Sample versus Broader Sample

Coverage is lower among residential customers among whom 27% of the full population have email addresses on file, while among GS<50 customers 44% have email addresses on file.

Rate Class	Full Population	Email Coverage	
Residential	48,421 records	13,154 records	**27%**
Small Business	4,496 records	1,928 records	44%

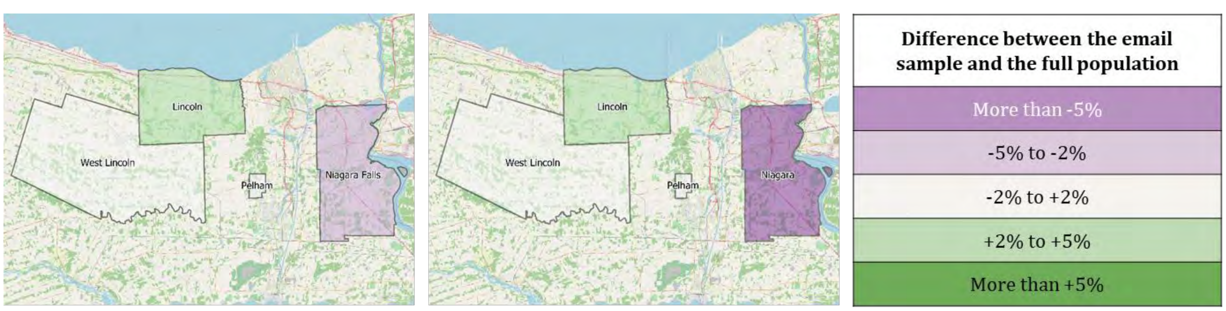
Average consumption is higher for customers in the email sample than it is among the full population for all rate classes. The largest differences exist among both groups of business customers. The final data is weighted on consumption to account for this difference.

Rate Class	Full Population	Those with email addresses	Difference
Residential	700 kWh	727 kWh	+4%
Small Business	2,154 kWh	2,413 kWh	+12%

Comparing the overall population to that of those with population with email addresses across known variables, we can see that no group is substantially underrepresented in the email sample. Therefore, no additional weighting "correction" is needed to account for the differences in sample groups.

Regional Segmentation

Customers are grouped into regions based on the service area listed on their account: Niagara Falls, Lincoln, West Lincoln, and Pelham.



Residential **GS<50**

Among residential customers, Niagara Falls as a region makes up 70% of the full population, but only 66% of the email sample. Lincoln makes up only 18% of the full population, but 21% of the email sample.

Among small business customers, the difference between the full population and the email sample is slightly larger for Niagara Falls and Lincoln. Niagara Falls is 65% of the full population and only 60% of the email sample, while Lincoln is 20% of the full population and 23% of the email sample.

The sample is stratified by region to ensure that the final email results reflect the actual regional composition of the population.

Based on the comparative results of the first phase of the customer engagement, INNOVATIVE is confident that the residential and small business online workbooks from Phase II are representative of NPEI's actual customer base.

Phase II Approach

In the **second phase**, NPEI and INNOVATIVE collectively developed an online "workbook" which was subsequently sent to all customers with an email address on record.

The residential and small business online workbooks featured two input streams:

1. The **representative stream** ensures a representative sample of customers are engaged, allowing for the generalizability of findings. This is a report of those responses.
2. The **voluntary stream** created an open process that allowed anyone who wants to be heard an opportunity to express themselves, including those who have not provided the utility with an email address.

The GS>50kW workbook was only accessible through a unique URL sent to customers. There was no voluntary stream for this version of the workbook.

In the **representative stream**, each customer received a unique URL that could be linked back to their annual consumption, region and rate class. In total, the workbook was sent to 13,855 customers through an e-blast from INNOVATIVE.

- 11,962 residential customers;
- 1,446 small business customers, and
- 447 GS > 50 kW customers

Beyond the initial e-blast, customers in all rate classes were sent multiple reminder emails to encourage participation. Additionally, to encourage participation amongst GS > 50 kW customers, NPEI staff placed follow-up telephone calls.

For residential and small business rate classes, responses from the representative stream were weighted by region and usage to ensure the responses were representative of the broader customer base. Due to sample size amongst GS > 50 kW customers, a decision was made to not weight data and present results in terms of n-size rather than percentages.

The **voluntary workbook** was promoted through NPEI's website, and social media.

Because INNOVATIVE cannot definitively link those who completed the online workbook through the voluntary stream, this portion of the sample cannot be deemed representative of the broader NPEI customer base.

While not representative of the broader customer base, the voluntary workbook is intended to ensure that customers who have not provided NPEI with an email address have an opportunity to participate.

An initial overview of the residential and small business workbook, based on 1,154 completed workbooks was shared with NPEI on December 12, 2019.

- The draft representative workbook results were shared on January 15, 2020.
- The draft voluntary workbook results were shared on January 15, 2020.

Throughout both Phase I and Phase II, INNOVATIVE regularly provided NPEI staff with progress updates by way of telephone, including preliminary results.

Appendix 1.0

CUSTOMER ENGAGEMENT

Exploratory Low-Volume Customer Focus Group Report

July 2019

Prepared for:

Niagara Peninsula Energy Inc.
7447 Pin Oak Drive
Niagara Falls, ON L2E 6S9

Customer Engagement:

Exploratory Low-Volume Customer Focus Group Report

July 2019

Confidentiality

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Niagara Peninsula Energy Inc. (NPEI). The conclusions drawn and opinions expressed are those of the authors.

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1. Executive Summary

In general, focus group participants were aware of the role Niagara Peninsula Energy Inc. (NPEI) plays in terms of their direct relationship as a customer (e.g. billing and maintaining reliability). Very few participants knew of NPEI's role in the larger electricity system in Ontario, including their limited decision-making power in regards to sourcing electricity and determining the price customers pay.

Participants were extremely satisfied with the customer service provided by NPEI. Generally, focus groups participants were also satisfied with their level of reliability; some participants noted that they had never experienced a single outage with NPEI. The biggest pain points for most participants was the price of delivery and lack of information that connects their electricity usage to the final amount charged on their bill.

Five key topics were discussed as emerging issues that will affect NPEI's ability to deliver electricity in the coming years. These included preparing the system for climate change, greening the grid and microgeneration, accommodating the increasing adoption of electric vehicles and devices, system maintenance, and a need for education among customers and the local community.

Following the discussion about emerging issues, participants were asked to rank the top three priorities that they want NPEI to focus on in their upcoming plan. The table below outlines the results of this exercise, which are discussed in greater detail on page 12. Price and cost efficiency were most often listed as the first priority, twice more than any other priority discussed.

Priorities	1st Priority	2nd Priority	3rd Priority	Total
Price/Cost Efficiency	15	7	8	30
System Maintenance/Reliability	3	8	3	14
Greening the Grid/Microgeneration	3	5	6	14
Need for Education	2	2	6	10
Customer Service/Tools	2	3	3	8
Supporting Local Community/Small Business	2	4	2	8
Planning for Growth/Increased Demand	2	1	3	6
Preparing System for Climate Change	2	0	0	2

2. Low-Volume Customer Focus Groups

2.1 Methodology

Objective: Using an exploratory research methodology, our objective was first to understand the customer journey, from initial contact (typically account initiation or transfer) through to the various other touchpoints customers typically encounter.

Our second objective was to obtain insights into what customers expect of Niagara Peninsula Energy Inc. (NPEI) particularly in terms of what represents value to customers and what customer priorities for NPEI are, both in context of valued outcomes and choices impacting customers.

Four low-volume customer focus groups were conducted in total across June 25th and 26th, 2019.

June 25th in Niagara Falls

1. Small Business Customers (9 participants) – 5:30pm to 7:30pm
2. Residential Customers (9 participants) – 8:00pm to 10:00pm

June 26th in West Lincoln

3. Small Business Customers (7 participants) – 5:30pm to 7:30pm
4. Residential Customers (8 participants) – 8:00pm to 10:00pm

Small Business participants received a $125 cash incentive as compensation for their time, while residential customers received $100. Participants were recruited from across Niagara Falls (June 25th) and Lincoln (June 26th) and qualified if they either paid their organization's electricity bill or had oversight on electricity management decisions.

We used a detailed *Discussion Guide* to moderate both focus groups. In both focus groups, a printed primer was shared with participants in the early part of the session to provide consistent contextual information on Niagara Peninsula Energy and the role it plays within Ontario's electricity system, and bill impact.

This report summarizes key findings, and offers observations and potential strategic avenues based on these groups and past research. *Respondent verbatim responses are in italics.* Regional differences or differences between residential and small business customers will be noted in the report where and if they exist. In general, our approach in reporting is to allow the respondents to be heard as much as possible, utilizing representative verbatim comments, offering interpretation and comment where necessary.

Please Note: Qualitative research does not hold the statistical reliability or representativeness of quantitative research. It is an exploratory research technique that should be used for strategic direction only.

A note on interpreting focus groups findings: In focus group research, the value of the findings lies in the *depth* and *range* of information provided by the participants, rather than in the *number* of individuals holding each view. References in this report such as "most" or "some" participants cannot be projected to the full population. Only a large sample, quantitative survey would be accurately projectable to the full population.

2.2 Customer Knowledge

Focus group participants varied widely in their knowledge about the role of NPEI in Ontario's electricity system. In each group, there was at least one customer who was able to explain NPEI's role with some detail.

> *"Admin. [NPEI] does all of our billing, sends out crews, [delivers electricity to] new subdivisions, and they do what you're doing, which is anticipating the future."*
>
> *"They make sure the lines are all up to date. [They manage] all the infrastructure in the Niagara Falls region."*

In most cases, participants were able to explain what NPEI does within the context of their experience as customers. This included mentions of billing, reliability, previous experience with conservation programs, and customer service.

> *"They have excellent twitter service. I can go online and or go on twitter and see exactly when my power if going to come up."*
>
> *"Take care of billing."*
>
> *"I think they have some education programs, do they not? For the public to stay away from power lines and what not? To teach children."*
>
> *"Conservation programs."*
>
> *"New services. Programs for getting fluorescent lighting."*

In most groups, general dissatisfaction with pricing came up in discussion early on. Often, this was expressed as a perceived unfairness about the cost of the delivery charge. Despite this, participants who had contacted NPEI to discuss their dissatisfaction with their bill were very satisfied with the level of customer service they received over the phone.

> *"Take our money"*
>
> *"We have a natural energy source in our backyard and yet my delivery charge is $40 a month."*
>
> *"I understood why [my bill] went up [when I called]. She was really good at looking into it and making a payment plan for me."*

After participants had an opportunity to share their knowledge about NPEI's role in the electricity system, they were given a one-page (double-sided) primer on the electricity system in Ontario and NPEI's role within it. The residential version of this handout is in the appendix of this report, for reference.

Participants were asked if anything in the handout was surprising or new information. Across all groups, participants stated previous unawareness to how the cost of their electricity service was divided. The majority of those who stated this was new information said they believed that the entirety of their bill went to NPEI.

> *"I thought they got at least a third of the bill."*
>
> *"I guess it's just a little bit of ignorance in not knowing how it was split up."*
>
> *"I had no idea they split it."*

Other surprising information included the degree to which NPEI controls aspects of participants' electricity service. Decisions surrounding generation and pricing were most commonly cited as things that participants initially thought NPEI had more control over. Some participants perceived inefficiencies that arise from having too many stakeholders in Ontario's electricity sector.

> *"I don't know if I was surprised, I kind of thought that they bought and distributed the power."*
>
> *"It's kind of confusing where all our money is going."*
>
> *"This was very educational for me. I didn't know who made these kind of decisions."*
>
> *"A lot of the issues we have are out of NPEI's control."*
>
> *"I didn't know that the cities themselves were stakeholders in this."*
>
> *"We could be a country that is totally self-sufficient, but we are not. We may take way too much time and research because there are so many hands in the pot. We have four levels of government and by the time that all these parties come together it's going to go beyond the scope of what was originally planned. What's going to happen when we putting everything off so far and then we will have nothing left?"*

Although most participants agreed that they were previously unaware as to how the bill was split among stakeholders, there was still some discussion as to whether or not the portion of delivery was too high or low.

> *"24% for delivery sounds high to me…3% line loss is too much"*
>
> *"To me, that seems low."*
>
> *"Seeing what the bottom line of their financial statements would be a different story. Sure they are taking 24% of all the bills, but how much is that?"*

After reviewing the handout, some respondents wanted more information about how decisions are made in Ontario's electricity system and NPEI's role within that process. Some participants wanted to know how comparable their service with NPEI is to other local distribution companies.

> *"Is it the energy board that makes sure that the utility is following the laws and policies that are in effect?"*
>
> *"One of the things that is missing here on this circle is the debt repayment charge."*
>
> *"Is there a legislature that municipalities have to own the utility?"*
>
> *"Do you have anything to compare NPEI's service to other utilities that serve similar customers?"*

A couple participants in the small business group in Lincoln said they had difficulty trusting the numbers presented on the handout and whether NPEI will really make changes based on customer feedback.

> *"I don't know if I trust these numbers."*
>
> *"We can hope, [but] whether they listen is the issue."*

2.3 Customer Journey

Customer experience varied more across region than customer type. In general, customers in the Niagara Falls group expressed satisfaction with interactions with NPEI more frequently and with more enthusiasm than those in the Lincoln groups.

Among participants who had previous experience with another utility (e.g. Toronto Hydro), comparisons between interactions and reliability were expressed and discussed. NPEI was nearly always perceived to have better customer service reliability than other utilities, more so among those with previous experience with Toronto Hydro than utilities in Hamilton and surrounding areas.

2.3.1 Points of Contact

Contact with NPEI varies across residential and small business customers. For most residential participants, most contact with NPEI occurs over the phone.

> *"I have phoned them a couple times. First time it was to get connected…It was a frustrating process to tell them that I didn't need to go through a lawyer to get connected. The other time was to tell them I was turning 65 and I needed a lower rate."*

> *"I called them to discuss a $900 bill. I live in a small house, no dishwasher, no furnace, no washer/dryer. The girl on the phone was really nice and calming, but I said the energy company should have a service where they can send somebody to your house. They said no and that they didn't have anything they could do for me."*

> *"I have called them to complain about the rebate."*

For small business customers across Niagara Falls and Lincoln, points of contact were more varied, with many Niagara Falls participants citing in-person experience with the LED lighting conservation programs.

> *"They called me to redo all my lighting to LED a while ago, for free. That was nice and quick and efficient."*

> *"I think they phoned first and then they came out. And then I wanted more and then I had to pay. But I got the fifteen hundred dollars' worth."*

Other points of contact for small business customers included visiting the head office to set up an account, going online, or calling customer service.

> *"When I have to go into the head office to get [a new account]."*

> *"Online, that's it. They are literally next door to us in their building. But online it's so easy and they are so nice if you have to call. Sometimes they ask me to go paperless, but I need the paper for my accounts payable."*

> *"Whenever there is an issue, we call them. Customer service has always been nice as opposed to talking to customer service from Bell Canada…"*

In Lincoln, one small business customer noted disappointment in the lack of communication from NPEI to small business customers. Citing previous conservation programs, small business customers in Lincoln noted a desire for more services that would help decrease energy use.

> *"I just feel like I'm not cared about. Call me and tell me what you can offer. I'm not in this industry, I am not a power guy. Help me, come in here and tell me what to do. Let me see them as somebody trying to help me."*

> *"An energy conservation audit [would be helpful], where they come in and see how much electricity is being used and where. I think some utilities still offer that service, but I don't know if they target it to larger commercial users."*

Across all groups, customers were very satisfied with the level of customer service they received from NPEI. While one customer expressed dissatisfaction with the automated telephone menu, customers who connected with a customer service representative had mostly, if not exclusively, positive things to say.

> *"I had to press 2 like 5 times before I actually got a person."*

> *"Turnaround time was extremely quick, everything we had done was really, really timely. Everything was done in about 6 hours, I would say."*

> *"We wanted to put decorative lights on our poles in the Fallsview area so we had some meetings with Hydro to figure out what we could put up there, they had to figure out what the actual cost was going to be so they could meter them. That was quite an easy process with them."*

> *"They kept in touch with me until the project was done. I felt like I won the lottery."*

> *"I have been here just under a year and I've never had to contact Niagara Peninsula Energy. I haven't ever had an outage."*

2.3.2 **Customer Expectations: Price and Reliability**

When the conversation was directed towards customers' expectations of NPEI rather than their experiences, participants in Niagara Falls were quick to express concerns over price.

> *"We try to deprive ourselves [of using electricity] but our bill doesn't change much."*

> *"You save but your bill never goes down."*

Some participants shared an expectation that prices in Niagara Falls should be lower because of the power generation provided by the Falls.

> *"We live in the city where it's produced. When they brought in the casinos they said that it would reduce what we pay and it hasn't."*

> *"We have a natural energy source in our backyard and yet my delivery charge is $40 a month."*

However, even among those that are frustrated with the cost of electricity, participants express appreciation for the customer service that NPEI provides.

> *"It often seems that they put in methods for you to save money and then they raise the rates. It's like you never really catch up on it. It feels like the onus is on the user to spend less money but they you never really bring the bill down. I have not had bad customer service ever, not even residentially. It is what it is. You're going to need electricity."*

Participants in the Niagara Falls residential group noted a distrust in how their bill amounts are calculated. They wanted an avenue to better monitor their energy use so that they can see the relationship between their usage and their bills. Most participants in this group were unfamiliar with the current service offering of NPEI through the online 'My Account' functions. This offering was something that participants said they would value and would be willing to pay more for.

> *"How do we know that the amount their charging us is the right amount? I don't see numbers."*
>
> *"That would be awesome to have. Data on how much energy we are using by the minute."*
>
> *"It would be great if a smaller company like Niagara Peninsula to be an innovator to have an app on your phone that you could check to see your usage."*
>
> *"Even if it's $5 more on your bill, most people won't even notice that. Some people might, but I think that I would be open to exploring that."*

In Lincoln, expectations of participants were more centred on reliability. Participants in the small business group mentioned improvements in the reliability of their service over the past years.

> *"When I have no power, I can't operate my business. But in the three years that I have had [my business] that has never been the case."*
>
> *"They used to have a lot of outages and it would be hours and hours and hours. It's better now."*

For many participants and across all groups, their relationship with NPEI is seen as little more than a bill to pay. Electricity is recognised as a necessary service and one with little-to-no choice involved throughout the customer journey.

> *"Expensive, but necessary. Not much you can do it. Excellent customer service. Both business and [residential]"*
>
> *"Essential, can't do anything about it."*
>
> *"I pay my bill that's it. I pay, I don't have another option. I pay my bill and that's the end of it."*

2.4 Emerging Issues

Frequently identified issues and associated priorities were consistent across all groups, and can be described as:

- **Preparing the System for Climate Change**
- **Greening the Grid and Microgeneration**
- **Changing Consumer Behaviour: Electric Vehicles and Devices**
- **System Maintenance**
- **Need for Education**

2.4.1 Preparing the System for Climate Change

Respondents understand the connection between reliability and weather through first-hand experience. Participants in Lincoln were especially understanding about the challenges of maintaining reliability though changing weather and during colder months.

Across all groups, participants were concerned that as weather continues to get more severe, the effects on reliability and the system in general will be a challenge.

> *"Weather is going to be more erratic. They have built the system to follow certain patterns, but we are going to start seeing more erratic patterns of weather. We are getting more peaks and valleys, especially in winter, which can cause a lot of issues with infrastructure."*

> *"How are they going to handle those big waves? Downed power lines, the trees?"*

Most participants agreed that addressing climate change should be an issue addressed proactively, rather than reactively.

> *"Don't wait for something catastrophic to happen to throw resources at it."*

There was a minority of participants who disagreed about whether climate change is a serious concern or not.

> *"I don't buy into this environment stuff. I don't drink the Kool-Aid. I think it's a way for government to have control."*

2.4.2 Greening the Grid and Microgeneration

Beyond preparing the system for more severe weather, participants noted a desire for NPEI to be a leader in green initiatives and reducing the impact of energy generation and consumption on the environment. Even without having much knowledge about specifics, participants were quick to name the environment as an important stakeholder in NPEI's decision-making.

> *"Sustainability. I think of it as renewable energy. Like lowering our impact when it comes to emissions."*

> *"What about their equipment? Is it needed to be replaced with electric vehicles? Is there office green? Are their vehicles green? Are they showing an example?"*

> *"Is burying the lines good for the environment? Or is it better for the environment if the lines are up in the air? Is it just better for us or better for the environment?"*

> *"Environment. I am just throwing that word out there, I don't know what it means, but I know that they should be environmentally responsible."*

Power storage and microgeneration through solar panels were most often mentioned by participants as ways to lessen the environmental impact of the grid. Cogeneration was also mentioned as a technology to support and encourage.

> *"There will be an increase in need for power. Oh the system we have enough now? And we are giving that away to the US? That's fine for now, but don't count on that to last. They need to seek out situations where we can make our own power."*

> *"Can they look at buying back power from their customers, do they have any control over that? Is that something they could look into?"*

> *"Technology and developing new sources of generations. Cogeneration technology like greenhouses and number of businesses that use a lot of heat can find efficiencies by working together through microgeneration."*

These were seen as attainable technologies to invest in given their broader adoption in Europe and potential economies of scale that could be captured through partnership with local developers.

> *"Why does it seem like Canada and the US is so far behind Europe in terms of putting solar panels on peoples' houses?"*

> *"The costs [to set up a solar panel] are probably half of what they were 5 to 6 years ago. If you put that in to a new subdivision, I bet you could get it down to $3,000 per house."*

2.4.3 **Changing Consumer Behaviour: Electric Vehicles and Devices**

Beyond making changes to the system, participating customers also 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.

> *"Smart cars are getting even more popular. Electric vehicles, they are definitely collecting more than the house and small business hydro now."*

> *"What about appliances that draw so much power?"*

> *"Now, we are using more things, more devices. More devices that use energy even when it's turned off."*

The potential issue of an increased reliance on electric-powered vehicles and devices is increased demand. Beyond this, participants also noted potential challenges of delivering power to charging stations that will need to accommodate the shorter range of electric vehicles in rural areas.

> *"Everybody is pushing electric cars. Some countries are mandating electric cars. If that happens, will our system be able to handle that? And what about in rural areas? Sure, you can drive for 100km, but if there is no station for 200km what are you going to do?"*

2.4.4 **System Maintenance**

Similar to the proactive approach to addressing climate change, participants want NPEI to take a proactive approach to managing infrastructure to maintain reliability. Despite there being very few participants who mentioned experiencing outages, many participants understood that it will cost to maintain their current level of reliability.

> *"Maintaining reliability of the distribution network."*
>
> *"Just ageing infrastructure."*
>
> *"I am not mad about the little bit of profit, because it allows them to be able to [deal with] the ageing infrastructure."*
>
> *"If you don't replace this stuff it's not going to be reliable."*

Participating customers wanted to know that there is a plan to replace infrastructure proactively.

> *"Is there a plan to replace infrastructure for the next 20 years?"*

2.4.5 Need for Education

Participants wanted NPEI to play a larger role in educating their customer base and community members. Once participants learned of the many other organizations represented on their electricity bill besides NPEI, they wanted to see NPEI as a community player and a voice for the customer during interactions with other electricity organizations.

> *"Of the three levels, the local level seems to be the most trustworthy. From that standpoint I would trust [NPEI] a lot more than [generation or transmission]."*
>
> *"Shouldn't there be more involvement in the community? Why do we not have more involvement in what's going on beyond a focus group? Where we go to City Hall and … I just don't think we have enough say in what goes on. Not just with Niagara hydro but with everybody."*
>
> *"The people in my building don't get a hydro bill and they don't get that information. So how do we get that information to all the people? About how much it costs to run businesses' electricity? I think that education is not just for the [customer] but for all the consumers using the utility. How can [NPEI] keep those people educated?"*

Participants expressed a desired to want to be more involved in the decision-making process of NPEI, but admitted that they aren't equipped with the knowledge or expertise to really get involved.

> *"If they have an annual report that we have access to. But can we understand it? Is it in laymen's terms?"*
>
> *"There's not an understanding of how much is involved in the coordination of burying lines. You have to tear up the road and the sidewalks. We don't have the knowledge on how to accomplish what we say we want to accomplish."*
>
> *"I don't think they are educating people about conservation in a basic way like they used to. They should talk to people about phantom power."*

On more than one occasion, town hall meetings were suggested by participants as a way to get involved in the community and educate customers on how the electricity system works.

> *"What about a town hall meeting. Help people to understand how the grid works."*

Participants across multiple groups said that greater transparency about how prices are made should be an important priority. Other participants said that they would be willing to pay more to learn more about how they are using their energy and how they might be able to reduce their consumption and therefore, their bill.

"They are a business and they have to operate to make money. That is what they are here for. There is nothing wrong with that. But they need to educate people as to why they are charging what they are paying."

"I would be willing to pay $50 bucks to have a guy come write up a two-page report about where I am at."

2.4.6 **Other Emerging Issues**

Some participants outlined other issues that, while not a main concern of most participants, may be underrepresented in the groups relative to the entire customer base.

These concerns included increased demand due to an increase in big business. With an increase in big businesses, some participants wanted to see NPEI play a role in protecting small businesses through targeted programs.

"Niagara is now getting some big businesses – it's growing."

"I would be willing to pay a little bit more to keep businesses operational. And I am not talking about multi-million dollar businesses but [small, local businesses]"

"Our tourism is what generates most of the income in Niagara Falls. That'll keep growing and there will be more hotels and more attractions and I think that will grow more then they expect."

"This area is going to boom in the next 10 years. As soon as the Go train starts operating back and forth from here to Toronto."

In addition to small businesses, participants noted that NPEI should make an effort to ensure that electricity remains affordable for low-income households.

"Electricity is a necessity, not a luxury. People need to be able to afford it."

"A lot of seniors are living on pension, and their bills are getting higher. Their houses could be paid off but now gas, water, hydro is as much as a mortgage payment."

Safety was also mentioned as an issue, and involved protecting employees and ensuring that the technologies employed are safe.

"Safety for their workers, they have to climb and it's always in the worst weather. What about their safety? It's a dangerous job."

"The effect of hydroelectric waves on our bodies. We have a very high cancer rate here and we have a lot of electricity here. And I think a lot more is known about it than is talked about. Even on how the electromagnetic fields with Wi-Fi affect us. It's a very hush hush thing, it's not an everyday conversation people have. Is there a way to make it safer? Does burying make is safer? Or does it make it worse?"

Some participants also mentioned a desire for NPEI to investigate potential opportunities for income that do not come directly from the ratepayer.

"Alternative sources of income that they can generate for ratepayers. Use the poles to create a mesh network for internet."

2.5 Identified Priorities

Participants were given the opportunity to rank the outcome priorities they identified. In the table below, we have outlined the number of respondents that listed each priority as either first, second, or third, from written feedback collected during the focus groups.

As an example, 15 participants listed price/cost efficiency as their first priority, while 7 and 8 participants listed it as their second and third priorities, respectively.

Priorities	1st Priority	2nd Priority	3rd Priority	Total
Price/Cost Efficiency	15	7	8	30
System Maintenance/Reliability	3	8	3	14
Greening the Grid/Microgeneration	3	5	6	14
Need for Education	2	2	6	10
Customer Service/Tools	2	3	3	8
Supporting Local Community/Small Business	2	4	2	8
Planning for Growth/Increased Demand	2	1	3	6
Preparing System for Climate Change	2	0	0	2

2.5.1 Emerging Issues as Priorities

When asked to give their top three priorities for NPEI based on the emerging issues discussed, the priority of issues did not reflect the amount of discussion around each topic. While participants tended to take a wide perspective when considering emerging issues, the responses for identified priorities seemed to be more personal and directly related to what participants expect from their direct relationship with NPEI. For instance, price, customer service, and supporting the local community were introduced as priorities. The discussed emerging issues appear in the following rank order:

- System Maintenance
- Greening the Grid and Microgeneration
- Need for Education
- Preparing the System for Climate Change

While 'Changing Consumer Behaviour: Electric Vehicles and Devices' does not appear on the list, it is represented in a broader category of preparing the system for growth and increased demand.

2.5.2 Price/Cost Efficiency

While price didn't come up as an emerging issue for NPEI, it is certainly the top priority participants want NPEI to focus on. Concerns over price were often brought up with concerns that they don't know enough about how their costs are calculated. Participants want to be able to trust that the amount on their bill is reflective of efficient management and based on their actual usage.

> *"I trust them but I don't think they are honest. They are taking advantage of us, we are desensitized to prices going up. They are definitely making more money than they are charging us."*

> *"Demonstrating efficiency to me and education the consumer on what they are doing. I want to trust that what I am paying for is the least amount that I have to pay."*

In the Lincoln small business group, there were few participants who expressed an interest in NPEI helping low-income households by being less strict on collections.

> *"It would be great if they could build up a greater reserve so that they could loosen up on collections."*

2.5.3 Customer Service/Tools

Across multiple groups, customers noted the importance of customer service and the tools that make interacting with NPEI easier. Customers' current experiences with customer service were noted to be excellent, but there was fear that changes in the future might affect the level of service they receive.

> *"Doug Ford is proposing to combine our cities. I am concerned that with us merging with St. Catherine's, we are going to not get the same customer service with Alectra that I am used to [with NPEI]."*

Customers also noted that they wanted to be better able to monitor their energy usage through online tools or an app on their phone. Many customers were unaware of the current service offering on NPEI's My Account portal. When asked about the types of communication tools they want NPEI to offer, texting tools were the top mention. Participants want to be able to receive outage updates for their account (or the account of a loved one) on their phone. Further, it was suggested that text updates could be used to monitor and manage usage.

> *"It would be nice to go online and like Cogeco, see what you use today."*

> *"Or like Telus. I want to see what my usage is and then text me if I am going over."*

> *"There are risk factors involved if you are responsible for a parent or child and you need to make sure the power is on."*

> *"Is it not possible to have at a local level to have text messaging to your cell-phones like [Amber Alerts]? That would be a terrific service."*

2.5.4 Supporting Local Community/Small Business

Supporting the local community and small businesses seemed to stem primarily from a discussion in the small business group in Niagara Falls. Following a discussion about the large box-stores that are soon opening in Niagara Falls, participants expressed concern that the smaller businesses won't be able to compete. Participants felt that NPEI could play a role in supporting small businesses through small business incentive programs.

> *"Incentives for small business because as large business comes and people are very excited that Costco is coming there is a price to pay for big box stores, they sell products cheaper, they get other types of incentives. Small businesses are the largest employer in Ontario and there aren't support for them. Those big box stores take a lot of business eat away at the ability with small-businesses to survive. That's part of all of our social responsibility."*

2.6 Turning Priorities into Themes

For the reference surveys, INNOVATIVE developed the priorities mentioned and discussed by NPEI customers in the focus groups into themes for testing in the reference surveys. The table below highlights how initiatives were captured and organized into themes:

Priorities from Focus Groups	Themes for Reference Surveys
• **Price/Cost Efficiency**	• Delivering electricity at reasonable distribution rates • Finding internal efficiencies and ways to find cost savings
• **System Maintenance/Reliability** • **Planning for Growth/Increased Demand**	• Ensuring reliable electrical service • Proactively replacing aging infrastructure that is beyond its useful life
• **Customer Service/Tools** • **Greening the Grid/Microgeneration**	• Providing tools and services that allow customers to better manage their electricity usage • Providing quality customer service and enhanced communications
• **Need for Education** • **Supporting Local Community/Small Business**	• Support the local economy and community groups through new incentives programs
• **Preparing System for Climate Change**	• Upgrading the electrical system to better respond to and withstand the impact of adverse weather

3. Appendices

The following two-page background primer was used in the residential customer focus groups.

Niagara Peninsula Energy's Role in Ontario's Electricity System

Ontario's electricity system is owned and operated by public, private and municipal corporations across the province. It is made up of three key components: **generation**, **transmission** and **distribution**.

1 Generation

Where electricity comes from.

Ontario's electricity is generated by nuclear, natural gas, hydroelectric and renewable technologies such as wind and solar. In Ontario, 70% of electricity is generated by *Ontario Power Generation*, which has generation stations across the province.

2 Transmission

Electricity travels across Ontario.

Once electricity is generated, it must be transported to urban and rural areas across the province. This happens by way of high voltage transmission lines that serve as highways for electricity. The province has more than 30,000 kilometres of transmission lines, most of which is owned and operated by *Hydro One*.

npe niagara peninsula energy inc. Your Local Utility

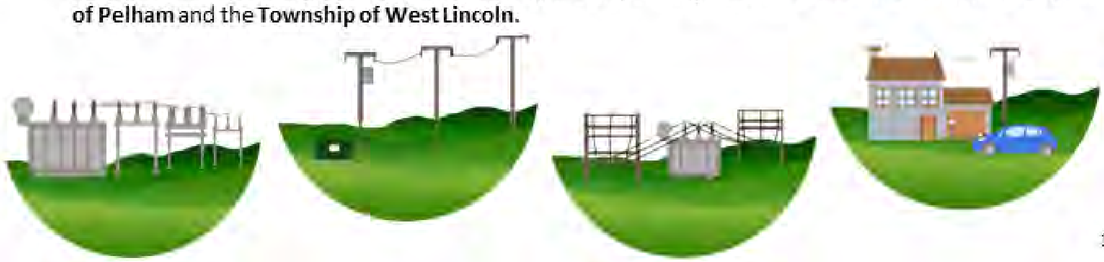
3 Local Distribution

Delivering power to homes and businesses in your community.

Niagara Peninsula Energy (NPEI) is responsible for the last step of the journey: distributing electricity to customers through its distribution system. This local distribution system includes transformer stations that decrease the voltage of the electricity so it can be used safely in your home or business.

There are approximately 1,451 km of overhead power lines and 573 km of underground cable. Through this distribution network, Niagara Peninsula Energy delivers electricity to more than 55,300 homes and businesses.

Niagara Peninsula Energy Inc. is jointly owned by the **City of Niagara Falls**, the **Town of Lincoln**, the **Town of Pelham** and the **Township of West Lincoln**.



1

Residential Electricity Bills:
Understanding where your money goes

Every item and charge on your bill is either mandated by the provincial government or approved by the Ontario Energy Board (OEB). The OEB sets electricity rates in Ontario.

For the typical residential customer, about **28%** of the electricity bill pays for **NPEI's** distribution system. The rest of the bill goes to power generation companies, transmission companies, regulatory agencies, and government taxes.

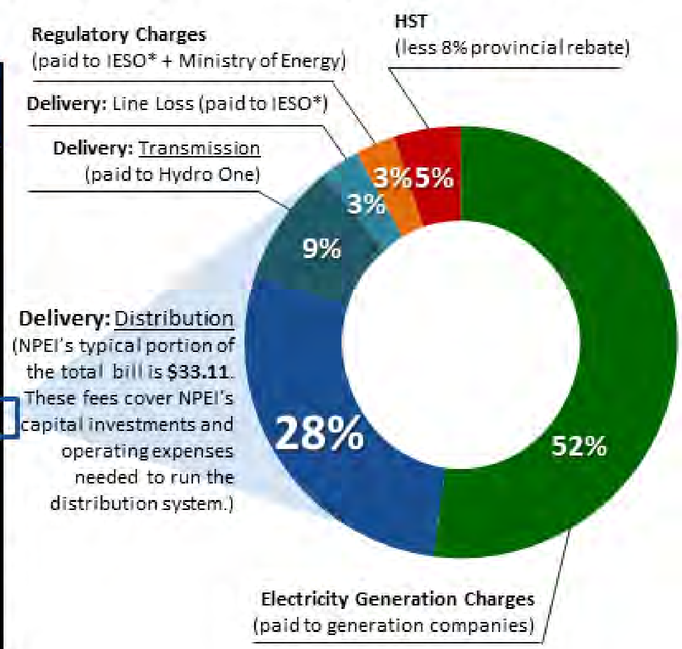
Niagara Peninsula Energy is responsible for billing customers for all of these costs, including any applicable taxes. The "Delivery" charge pays for both the cost of transmission and the cost of distribution. **Only the distribution portion is retained by NPEI to pay for operating and maintaining its part of the system.**

Sample Residential Bill

NPEI Monthly Bill
(Based on consumption of 750 kWh)

NPEI's portion: **$33.11**

Your Electricity Charges	
Electricity	
Off-Peak @ 6.5 ¢/kWh	31.69
Mid-Peak @ 9.4 ¢/kWh	11.99
On-Peak @ 13.4 ¢/kWh	18.09
Delivery	45.15
Regulatory Charges	3.32
Total Electricity Charges	$116.70
HST	14.46
8% Provincial Rebate*	(-$8.90)
Total Amount	$116.79



* IESO = Independent Electricity System Operator.

How are electricity rates determined in Ontario?

The Ontario electricity sector is regulated by the **Ontario Energy Board** (OEB). One of the OEB's roles is to review the distribution plans of all electricity distributors and set the rates that they can charge customers.

Niagara Peninsula Energy (NPEI) is funded by the distribution rates paid by its customers. Periodically, NPEI is required to file an application with the OEB to determine the funding available to operate and maintain the distribution system. NPEI must submit evidence to justify the amount of funding it needs to safely and reliably distribute electricity to its customers.

INNOVATIVE RESEARCH GROUP

Reference Survey Report

Customer Engagement

niagara peninsula energy inc.

This report and all of the information and data contained within it may not be released, shared or otherwise disclosed to any other party, without the prior, written consent of Niagara Peninsula Energy Inc.

August 2019

STRICTLY PRIVILEGED AND CONFIDENTIAL

Niagara Peninsula Energy Inc.
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Overview

Research Objective

As part of its Phase I Customer Engagement, Niagara Peninsula Energy Inc. (NPEI) commissioned Innovative Research Group (INNOVATIVE) to survey its residential and small business customers. Among each customer type, INNOVATIVE conducted parallel telephone and online surveys.

Conducting parallel bi-modal surveys serves two primary purposes:

1. **To gather feedback and insights on the *priorities*, *preferences* and *needs* important to low-volume customers**.
   Feedback from these surveys will help NPEI planners and engineers inform the design of the utility's DSP and Business Plan, which will be shared in draft, with customers in Phase II of this engagement.

2. **To establish baselines and develop weights that will allow NPEI to move to an online methodology for future phases of its low-volume customer engagement program**.
   Determining the baseline and understanding the difference between customers with known email addresses (email sample), and the broader customer base (telephone sample), is a critical step for utilities that wish to migrate to representative online survey methodologies in the second phase of their customer engagement. Where significant differences exist between the email sample and the broader customer base (e.g. demographics, firmographics, attitudes, and opinions), the insights gained from these parallel surveys can be used to develop weights, which will account for the differences and ensure generalizable findings.

Benefits of Moving to an Online Methodology

With known emails for approximately 27% of residential customers, and 45% of its small business customers, NPEI could consider migrating from a generalizable pure-telephone methodology to a generalizable pure-online methodology in Phase II of its customer engagement.

The mode of Phase II – the presentation NPEI's draft DSP and Business Plan in interactive workbook form – is well structured to support and demonstrate the benefits of a pure-online methodology. These benefits include:

- Ability to explain concepts using clear, concise, multi-media visuals (e.g. diagrams, pictures, videos).
- Increased potential survey length; it has been documented that respondents are more likely to spend more time participating in online surveys versus telephone surveys.
- Reduced costs as online surveys are less costly than telephone surveys.
- Removing the human element of a telephone survey ensures, that the information NPEI intends to delivery remains invariably consistent.

This report documents the results of four surveys conducted by INNOVATIVE among NPEI's low-volume customers (small business and residential) and provides recommendations on appropriate weighting for future NPEI online survey methodologies.

Comparing known sample variables

Coverage and Consumption Analysis

Comparing the overall population to the sample of that population with email addresses across known variables, we can see that the email sample is largely representative of the overall population of customers.

Overall Coverage

Coverage is lower among residential customers among whom only 27% of the full population have email addresses on file, while among GS<50 customers 44% have email addresses on file. A total of 4710 residential and 88 GS<50 customers did not have either an email address or a telephone number on file.

Rate Class	Full Population	Telephone Coverage	Email Coverage	
Residential	48,421 records	42,958 records	13,154 records	**27% of the full population**
GS<50	4,496 records	4,382 records	1,928 records	**44% of the full population**

Average Consumption

Average consumption is higher for customers in the email sample than it is among the full population for all rate classes. The largest differences exist among both groups of business customers. The final data is weighted on consumption to account for this difference.

Rate Class	Full Population	Telephone Sample	Email Sample	Diff. between email and full
Residential	700 kWh	726 kWh	727 kWh	**+4%**
GS<50	2,154 kWh	2,158 kWh	2,413 kWh	**+12%**

Sector Comparison (GS<50)

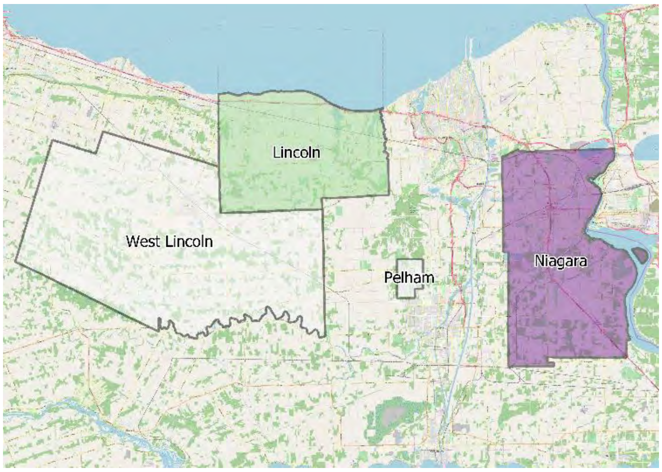
The largest differences in sector of operation come in the GS<50 rate class where Business/Commerce businesses are slightly under-represented and Resource/Construction/Manufacturing businesses are slightly over-represented.

Rate Class	Full Pop.	Telephone Sample	Email Sample	Diff. Between email and full
Business/Commerce	43%	43%	39%	-4%
Public/Cultural	29%	30%	30%	+1%
Resources/Construction/ Manufacturing	26%	26%	30%	+3%

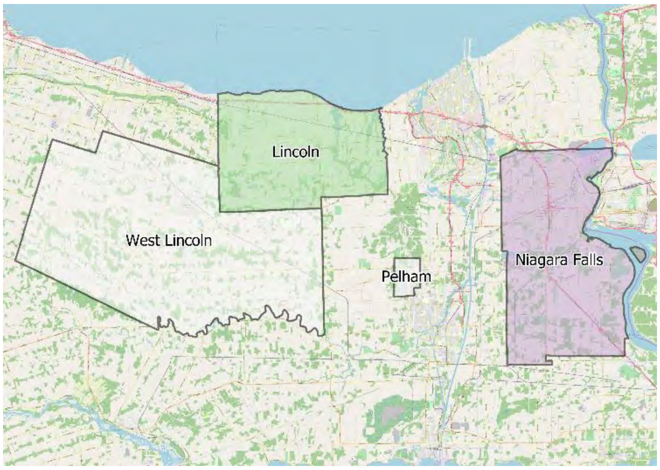
Comparing known sample variables

Regional Analysis

GS<50



Residential



Comparing the overall population to the sample of that population with email addresses across known variables, we can see that no group is substantially underrepresented in the email sample.

Customers are grouped into regions based on the service area listed on their account: Niagara Falls, Lincoln, West Lincoln, and Pelham.

Among residential customers, Niagara Falls as a region makes up 70% of the full population, but only 66% of the email sample. Lincoln makes up only 18% of the full population, but 21% of the email sample.

Among small business customers, the difference between the full population and the email sample is slightly larger for Niagara Falls and Lincoln. Niagara Falls is 65% of the full population and only 60% of the email sample, while Lincoln is 20% of the full population and 23% of the email sample.

The sample is stratified by region to ensure final email results reflect the real regional composition of the population

Difference between the email sample and the full population
More than -5%
-5% to -2%
-2% to +2%
+2% to +5%
More than +5%

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Sample Validation

Email Sample vs. Telephone Sample

For the most part, responses from the telephone and online surveys are very similar within both customers types. However, there are a few distinct difference that are worth noting. The table below documents the differences between the *email* and *telephone* samples.

Residential	GS < 50 kW
Age: Telephone respondents are slightly older than online respondents (age 55+: 67% vs. 62% respectively). **Education:** Telephone respondents are less likely to have continued with education beyond high school than online respondents (69% vs. 80%, respectively). **Household size:** Telephone respondents are more likely to live in single person households than online respondents (26% vs. 14%, respectively).	**Sector:** Telephone respondents are more likely than online respondents to be represented in the commercial sector (33% vs. 24%). **Hours of Operation:** Telephone business respondents are more likely than online respondents to operate during regular business hours (76% vs. 54%).
Familiarity and Satisfaction with NPEI: Telephone respondents are, in general, less familiar (67% vs. 80%) but more satisfied (89% vs. 82%) than online respondents.	**Familiarity and Satisfaction with NPEI:** Telephone respondents are, in general, less familiar (68% vs. 86%) but more satisfied (87% vs. 79%) than online respondents.

Weighting Convention

Given the coverage of email addresses (27% of the customer base among residential and 45% of small business customers) and similarities in known account characteristics (average consumption, language, and region), NPEI's email sample is a good representation of the broader customer base.

While the telephone and online surveys returned similar results, there were some differences on key demographics and firmographics (business characteristics), as well as customer knowledge, attitudes and beliefs that merit a weighting convention, which will be applied in Phase II of the engagement process.

Key Findings

Phase I Customer Engagement

Based on a review of the OEB handbook and previous rate application decisions, NPEI's customer engagement focuses on two types of questions: ***needs*** and ***preferences*.**

- **Needs questions** focus on understanding the gap between the services and experience customers want and the services and experience customers are receiving.
- **Preference questions** focus on customer views about the outcomes the utility should focus on, priorities among those outcomes, and trade-offs illustrated by choices on specific programs or the pacing and prioritization of investments.

The following key findings are the results of NPEI's random digit dialling telephone survey among residential and small business customers (GS<50kW). Given the similarity between telephone and online results, only the former are reported in the key findings. The full report contains all results.

What are customers' needs?

The clear majority of NPEI residential and small business customers are satisfied with the current service they receive. When asked how NPEI can improve service, top responses for residential customers were "nothing", followed by "lower or reduce rates". Small business customers, however, placed greater emphasis on the lowering or reduction of rates.

	Residential	Small Business
Overall Satisfaction	89% satisfied	82% satisfied
Improving services to customers		
1st	Nothing	*Lower or reduced rates*
2nd	*Lower or reduced rates*	Nothing

Key Findings

Phase I Customer Engagement

What outcomes do customers prioritize?

Customers don't expect NPEI to just focus on one outcome. In fact, the majority of both residential and small business customers feel that the following outcomes are *extremely important*.

- Ensuring reliable electrical service
- Delivering electricity at reasonable distribution rates
- Providing quality customer service and enhanced communications
- Proactively replacing aging infrastructure that is beyond its useful life
- Finding internal efficiencies and ways to find cost savings
- Upgrading the electrical system to better respond to and withstand the impact of adverse weather and climate change

Among competing outcomes, *price*, *reliability*, and *finding internal cost efficiencies* are the top three priorities for both residential and small business customers. When ranked relative to other priorities, NPEI customers see price as the top outcome that the utility should focus on.

Ranking Priorities	Residential	Small Business
Top Priority	Delivering electricity at reasonable distribution rates	Delivering electricity at reasonable distribution rates
2nd Priority	Ensuring reliable electrical service	Ensuring reliable electrical service
3rd Priority	Finding internal efficiencies and ways to find cost savings	Finding internal efficiencies and ways to find cost savings

What reliability outcomes do customers prioritize?

Residential and small business customers have consistent priorities when it comes to reliability. Reducing the *overall number of outages, the overall length of outages,* and improving *restoration time* are the top three priorities for both rate classes.

Ranking Priorities	Residential	Small Business
Top Priority	Reducing the overall number of outages	Reducing the overall number of outages
2nd Priority	Reducing the overall length of outages	Reducing the overall length of outages
3rd Priority	Reducing the length of time to restore power during extreme weather events	Reducing the length of time to restore power during extreme weather events

Key Findings

Phase I Customer Engagement

What investment trade offs do customers value most?

While keeping price at a reasonable and affordable level is an important priority for customers, the majority feel that investing in the grid to maintain reliability, is preferable to deferring investments to keep bills low.

The majority of residential and small business customers are willing to consider paying more to invest in maintaining reliability, equipping staff with equipment and IT systems, proactively investing in system capacity, and modernizing the grid knowing that it could eventually save money.

Further, the majority of customers support proactive investment in both system capacity and grid modernization. Relative to other trade offs support for investment in system capacity is least intense.

Replacing Aging Infrastructure (System Renewal)

The majority of residential and small business customers are supportive of NPEI making investments in aging infrastructure in order to maintain reliability, even if that results in small rate increases. This option is most strongly supported by small business customers, when compared to other trade offs.

System Renewal (% of customers who selected option)	Residential	Small Business
Invest what it takes to maintain reliability	**62%**	**64%**
Defer investments to lessen bill impacts	**26%**	**19%**

Keeping the Business Running (General Plant)

The majority of residential and small business customers support NPEI making the necessary investments to ensure its staff have the equipment and IT systems that are needed to manage the system efficiently and reliably. This option is most strongly supported by residential customers, when compared to other trade offs.

General Plant (% of customers who selected option)	Residential	Small Business
Make investments necessary	**64%**	**55%**
Find ways to make do with equipment	**23%**	**28%**

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Key Findings

Phase I Customer Engagement

Proactive Investments in System Capacity (System Service)

A slim majority of residential and small business customers are more inclined to say that NPEI should proactively invest in system capacity infrastructure to ensure customers in high growth areas do not experience a decrease in reliability.

Relative to other trade offs, this option has the weakest level of support.

System Service (% of customers who selected option)	Residential	Small Business
Proactively invest in system capacity	**56%**	**52%**
Delay investments in system capacity	**27%**	**28%**

Proactive Investments in Grid Modernization (New Technology)

The majority of residential and small business customers are supportive of NPEI proactively investing in modernizing the grid now, knowing it will cost more now, but could eventually save customers money down the road.

Grid Modernization (% of customers who selected option)	Residential	Small Business
Make proactive investments	**62%**	**55%**
Make investment prioritizing lowest cost	**25%**	**21%**

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Methodology & Respondent Profiles

Reference Survey Methodology

Survey Design

This report documents the results of four surveys conducted by INNOVATIVE among NPEI's low-volume customers (small business and residential).

The **telephone surveys** were fielded from **July 9th to 26th, 2019** amongst a random sample of **n=500** (unweighted n=505) residential and **n=87** (unweighted n=87) small business customers.

Both telephone surveys were weighted by region and consumption quartiles within their respective rate classes to produce a representative sample of NPEI's customer base.

The final sample includes both landline and cell phone respondents, so that individuals who don't have a landline are represented. The margin of error is approximately ±4.5%, 19 times out of 20 for the residential survey and approximately ±10.4%, 19 times out of 20 for the small business survey.

The **online surveys** were fielded from **July 12th to 29th, 2019** amongst **n=939** (unweighted n=939) residential and **n=71** (unweighted n=71) small business customers.

Both online surveys were weighted by region and consumption quartiles within their respective rate classes to report on a representative sample of NPEI 's customer base.

The margin of error is approximately ±3.2%, 19 times out of 20 for the residential survey and approximately ±11.4%, 19 times out of 20 for the small business survey.

Sample Design

NPEI provided INNOVATIVE with confidential access to its customer lists in order to conduct this research. The customer list included information on region, electricity consumption, and preferred language for communications, as well as all available telephone numbers and email addresses.

Since only a subset of the customers on the lists have email addresses on file, INNOVATIVE has conducted a baseline analysis to see how customers with email addresses differ from the broader customer base, followed by a detailed comparison between online and telephone survey results. The following pages detail the sampling methodology used for this research.

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Residential Sample

The residential telephone survey followed a stratified random sampling methodology. This is a method of sampling that involves the division of a population into smaller groups known as strata. In stratified random sampling, the strata are formed based on a group's shared attributes or characteristics (in this case, customer service area and electricity usage). A random sample from each stratum is taken in a number proportional to the stratum's size when compared to the customer population. These subsets of the strata are then pooled to form a random sample.

In the telephone survey, residential customers were divided into strata based on service area populations. Within service area populations, residential customers were then divided into quartiles based on annual electricity usage to ensure the sample has a proportionate mix of customers from *low*, *medium-low*, *medium-high*, and *high* electricity usage households. Weights were applied to adjust the *observed strata* to ensure a representative customer base.

Telephone Residential Sample

Region	Unweighted N					Weighted N				
	Consumption Quartiles					Consumption Quartiles				
	Low	Medium-Low	Medium-High	High	Total	Low	Medium-Low	Medium-High	High	Total
Niagara Falls	84	84	80	87	**335**	83	83	83	83	**332**
Pelham	4	4	4	4	**16**	4	4	4	4	**16**
Lincoln	24	24	27	20	**95**	24	24	24	24	**96**
West Lincoln	15	13	15	16	**59**	14	14	14	14	**56**
Total	127	125	126	127	**505**	125	125	125	125	**500**

The online survey data has been weighted by region and consumption to ensure a representative customer base.

Online Residential Sample

Region	Unweighted N					Weighted N				
	Consumption Quartiles					Consumption Quartiles				
	Low	Medium-Low	Medium-High	High	Total	Low	Medium-Low	Medium-High	High	Total
Niagara Falls	137	164	112	132	**545**	156	156	156	156	**625**
Pelham	8	8	5	8	**29**	7	7	7	7	**27**
Lincoln	74	71	61	27	**233**	44	44	44	44	**178**
West Lincoln	44	32	36	20	**132**	27	27	27	27	**109**
Total	263	275	214	187	**939**	235	235	235	235	**939**

Small Business Sample

Like the residential telephone survey, the **small business telephone** survey followed stratified random sampling methodology. Weights were applied to adjust the *observed strata* to ensure a representative customer base.

Telephone Small Business Sample

Region	Unweighted N					Weighted N				
	Consumption Quartiles					Consumption Quartiles				
	Low	Medium-Low	Medium-High	High	Total	Low	Medium-Low	Medium-High	High	Total
Niagara Falls / Pelham	13	12	14	10	**49**	14	14	14	14	**58**
Lincoln / West Lincoln	6	8	10	14	**38**	7	7	7	7	**29**
Total	19	20	24	24	**87**	22	22	22	22	**87**

The online survey data has been weighted by region and consumption to ensure a representative customer base.

Online Small Business Sample

Region	Unweighted N					Weighted N				
	Consumption Quartiles					Consumption Quartiles				
	Low	Medium-Low	Medium-High	High	Total	Low	Medium-Low	Medium-High	High	Total
Niagara Falls / Pelham	13	3	13	10	**39**	12	12	12	12	**47**
Lincoln / West Lincoln	4	8	12	8	**32**	6	6	6	6	**24**
Total	17	11	25	18	**71**	18	18	18	18	**71**

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Demographics

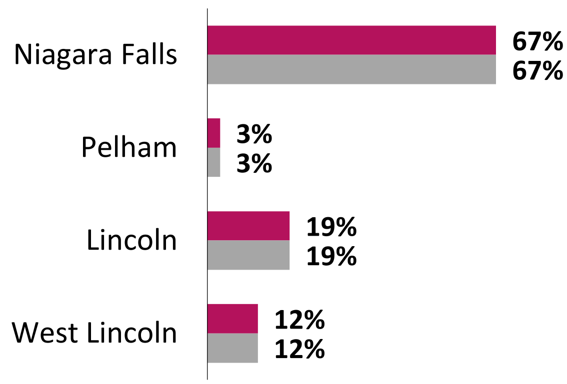
Residential Respondent Profile

Residential

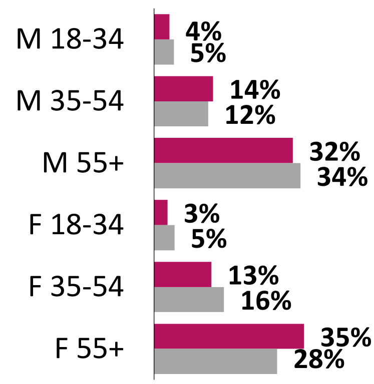
Telephone

Online

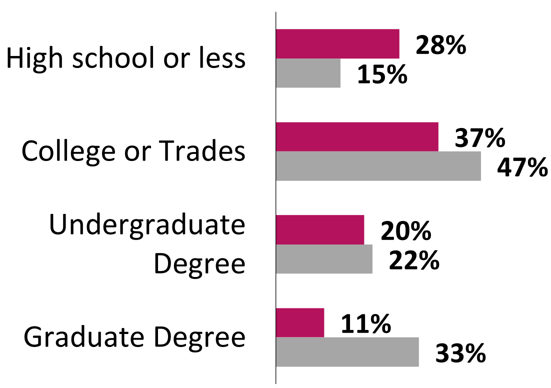
Region



Age-Gender

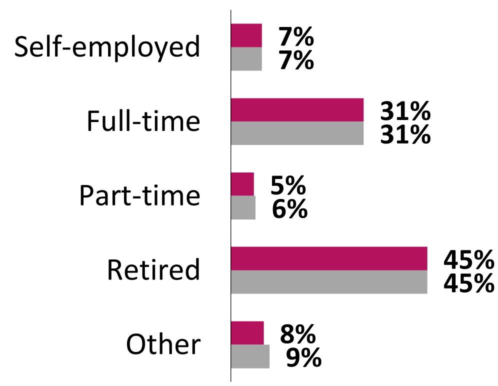


Education



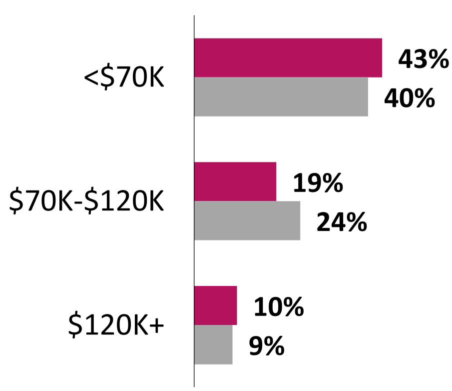
Note: 'Prefer not say' (T: 3%; O: 5%) not shown

Employment



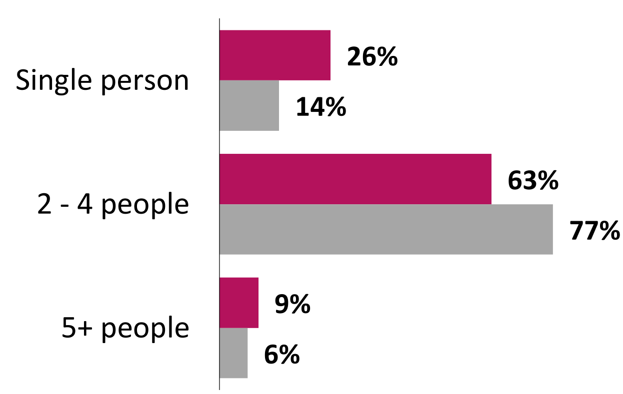
Note: 'Prefer not say' (T: 2%; O: 4%) not shown

Household Income (After Tax)



Note: 'Prefer not say' (T: 28%; O: 27%) not shown

Household Size



Note: 'Prefer not to say' (T: 3%; O: 1%) not shown

Firmographics

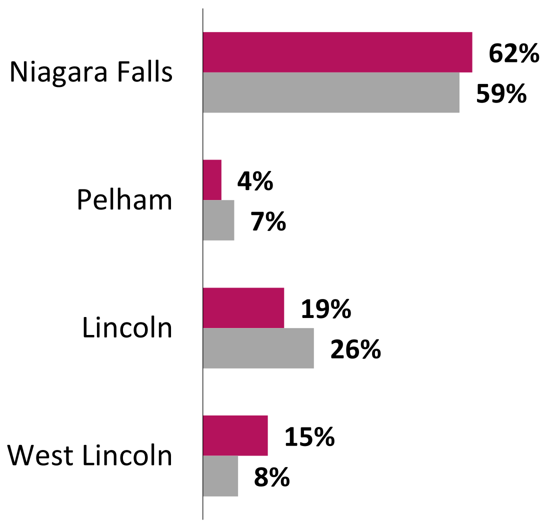
Small Business Respondent Profile

Small Business

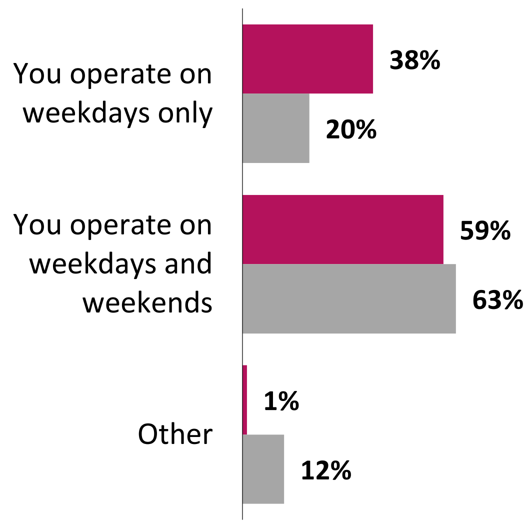
Telephone

Online

Region

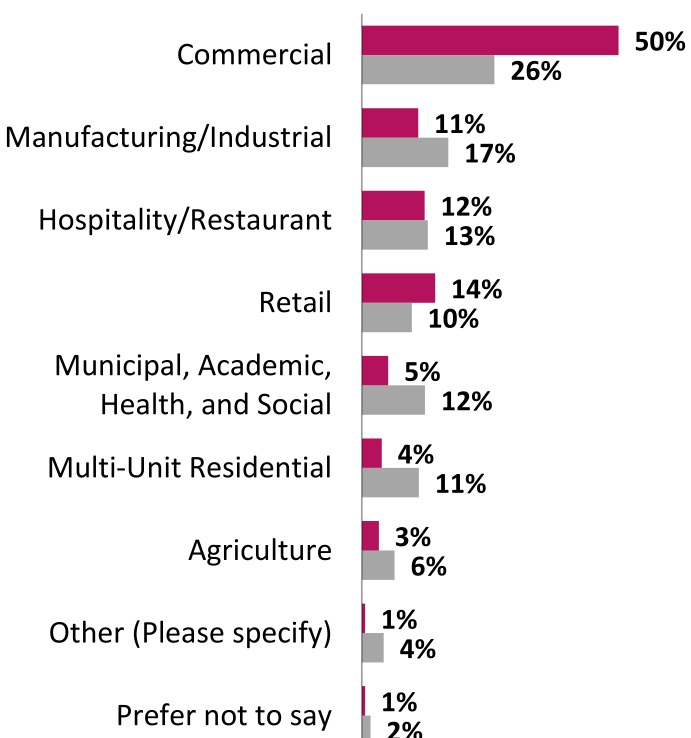


Days of operation



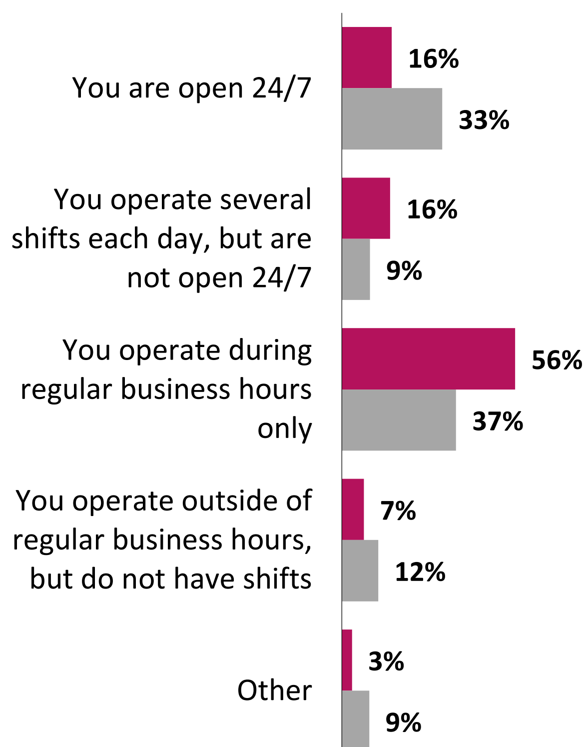
Note: 'Prefer not to say' (T: 0%; O: 6%) not shown

Sector



Note: 'Prefer not to say' (T: 1%; O: 2%) not shown

Hours of operation



Note: 'Prefer not to say' (T: 0%; O: 1%) not shown

Environmental Controls

It is important to distinguish between what is within, and what is outside of NPEI's influence or control when it comes to drivers of customer opinion.

Perceptions of distributors often tend to move with general perceptions of ***provincial government management in the sector*** rather than in response to the local utility.

In addition, perceptions of utilities are also strongly correlated with **financial circumstances**. In tough times perception and preference can change because customers are struggling with their bills, not because of anything the company has, or has not, done.

Control questions help distributors distinguish between:

a) utility driven programs that impact customer opinion; and

b) uncontrollable external drivers that impact customer opinion.

When conducting research in the energy sector, INNOVATIVE often tests multiple environmental control to assess what role predispositions (customer values and beliefs – which can be difficult and costly to change) play in the formation of opinion towards a utility.

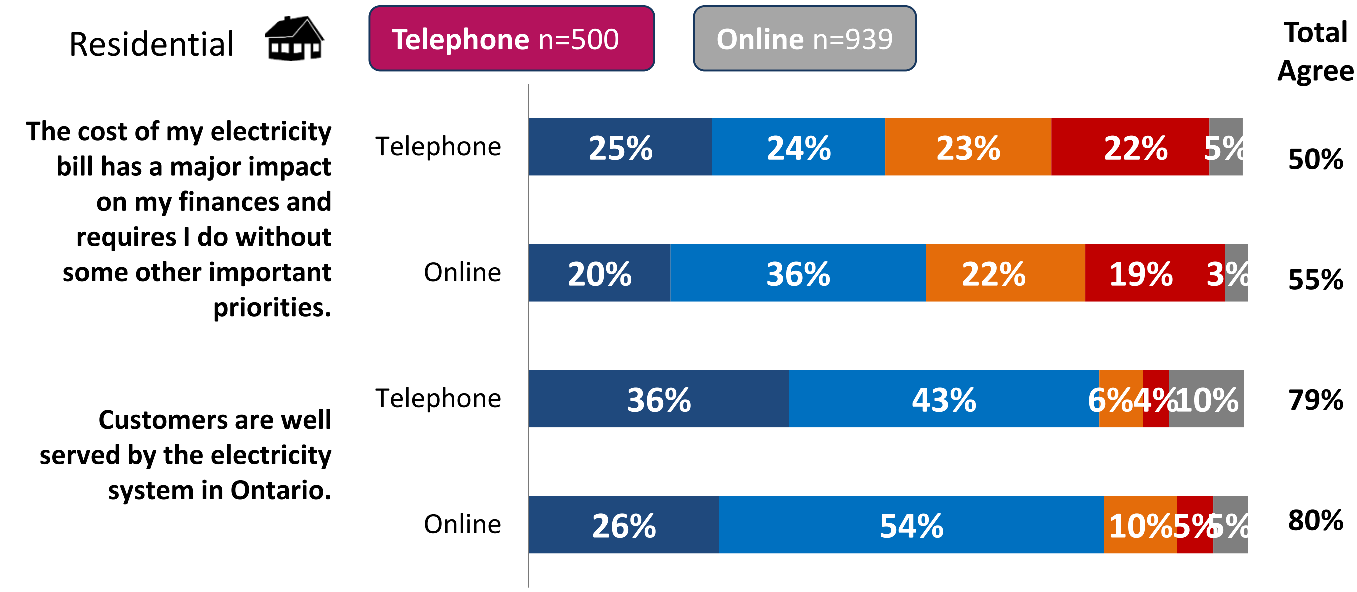
In this study, our environmental controls focus on two key questions to help capture external phenomena:

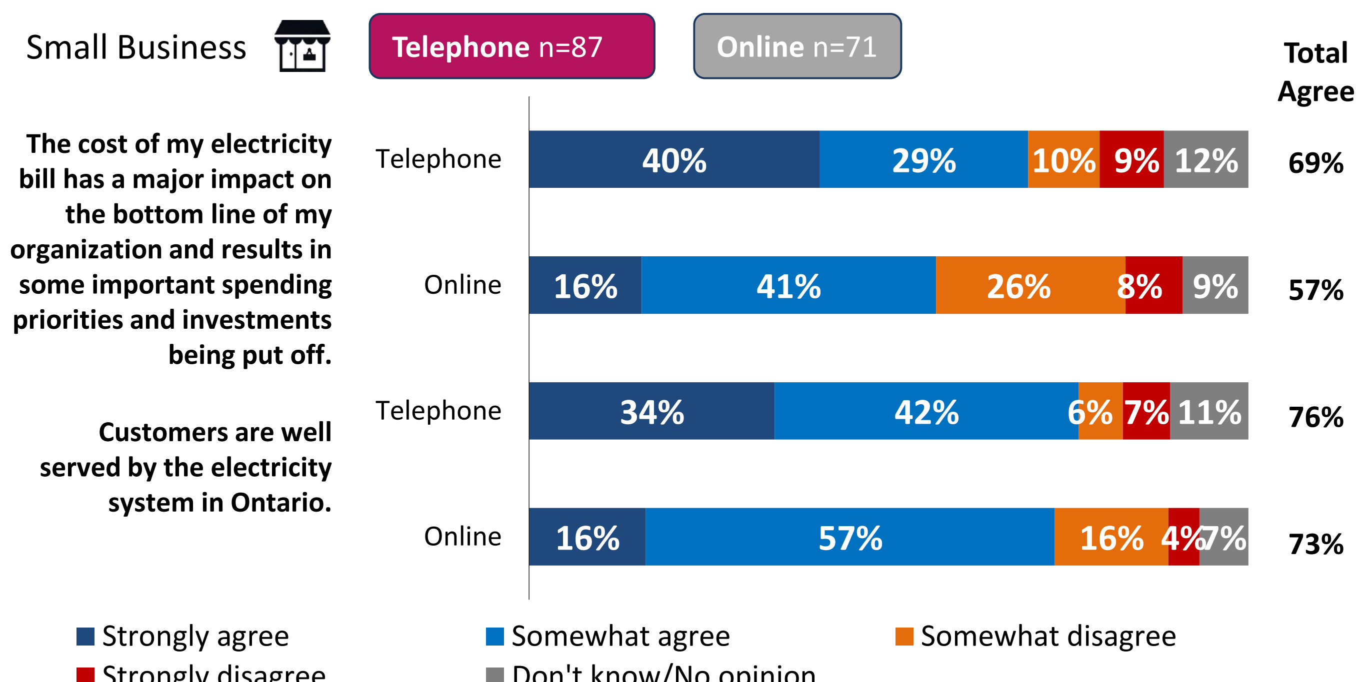
Government Management of the Electricity System: *Consumers are well served by the electricity system in Ontario.*

Financial Circumstances: *The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.*

Environmental Controls
Customer Feedback

Q For each statement please tell me if you would strongly agree, somewhat agree, somewhat disagree or strongly disagree. If you don't know enough to say or don't have an opinion just let me know.





Note: Sums added before rounding. 'Refused' not shown.

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Customer Perceptions

Knowledge, CSAT, Needs

Introduction & Core Measure

Preamble

"

*The survey questions are about **Niagara Peninsula Energy** and the local electricity system in your community.*

Today we'd like to talk to you about three things:

- *We will talk about your experience with **Niagara Peninsula Energy**;*
- *We will talk about the outcomes that matter most to you; and*
- *We will talk about some trade-offs in planning future investments.*

First, let's talk about your experience.

*While you might have multiple accounts with **Niagara Peninsula Energy**, for this survey, we want you to think about your overall experience as a [residential/small business] customer.*

*The following questions are about **Niagara Peninsula Energy's** distribution system. This is the system that takes the electricity from high-voltage transmission towers and brings it to your home through a network of wires, poles and other equipment that is owned and operated by **Niagara Peninsula Energy**.*

"

Familiarity with Niagara Peninsula Energy

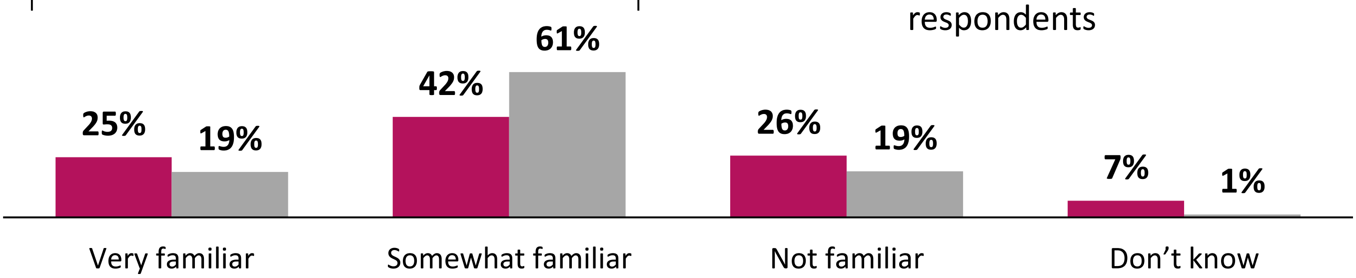
Q How familiar are you with Niagara Peninsula Energy, which operates the electricity distribution system in your community?

Telephone | Online

Residential

Familiar
Telephone: 67%
Online: 80%

n=500 | n=939

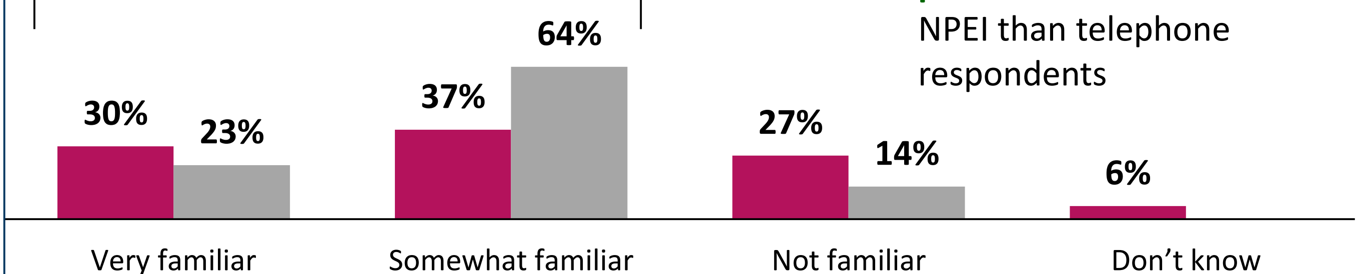


Difference:
Online are **+12 percentage points** more familiar with NPEI than telephone respondents

Small Business

Familiar
Telephone: 68%
Online: 86%

n=87 | n=71



Difference:
Online are **+18 percentage points** more familiar with NPEI than telephone respondents

Note: Sums added before rounding.

Satisfaction with Niagara Peninsula Energy

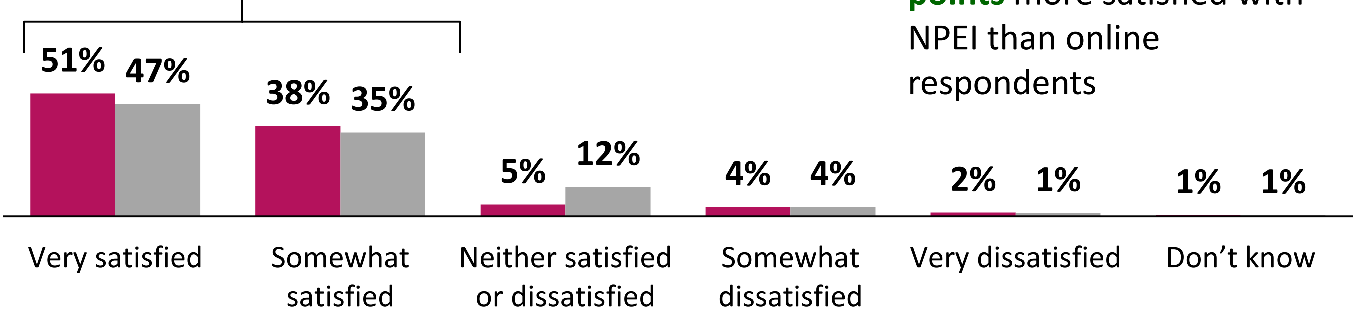
Q Thinking specifically about the services provided to you and your community by **Niagara Peninsula Energy**, overall, how satisfied or dissatisfied are you with the services that you/your organization receive? Would you say you are very satisfied, somewhat satisfied, neither satisfied nor dissatisfied, somewhat dissatisfied, very dissatisfied or would you say you don't know?

Telephone | Online

Residential

n=500 | n=939

Satisfaction
Telephone: 89%
Online: 82%

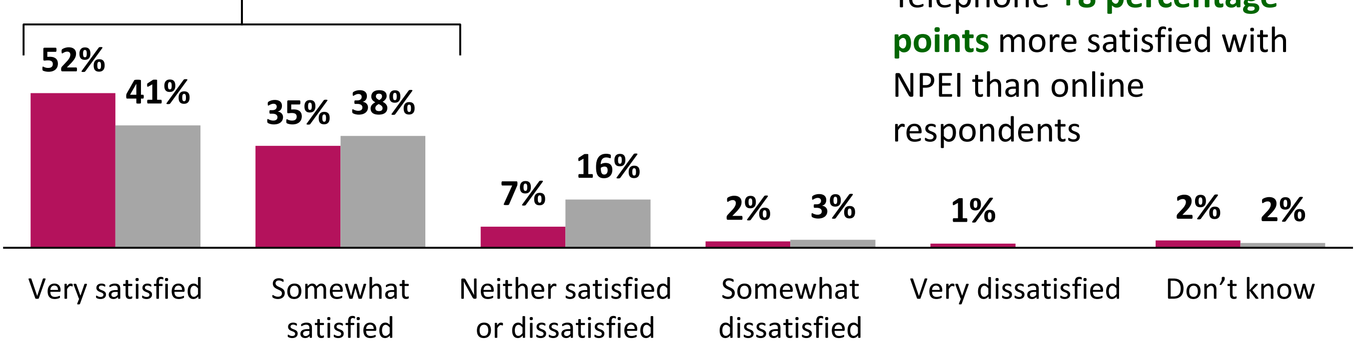


Difference:
Telephone **+7 percentage points** more satisfied with NPEI than online respondents

Small Business

n=87 | n=71

Satisfaction
Telephone: 87%
Online: 79%



Difference:
Telephone **+8 percentage points** more satisfied with NPEI than online respondents

Note: Sums added before rounding.

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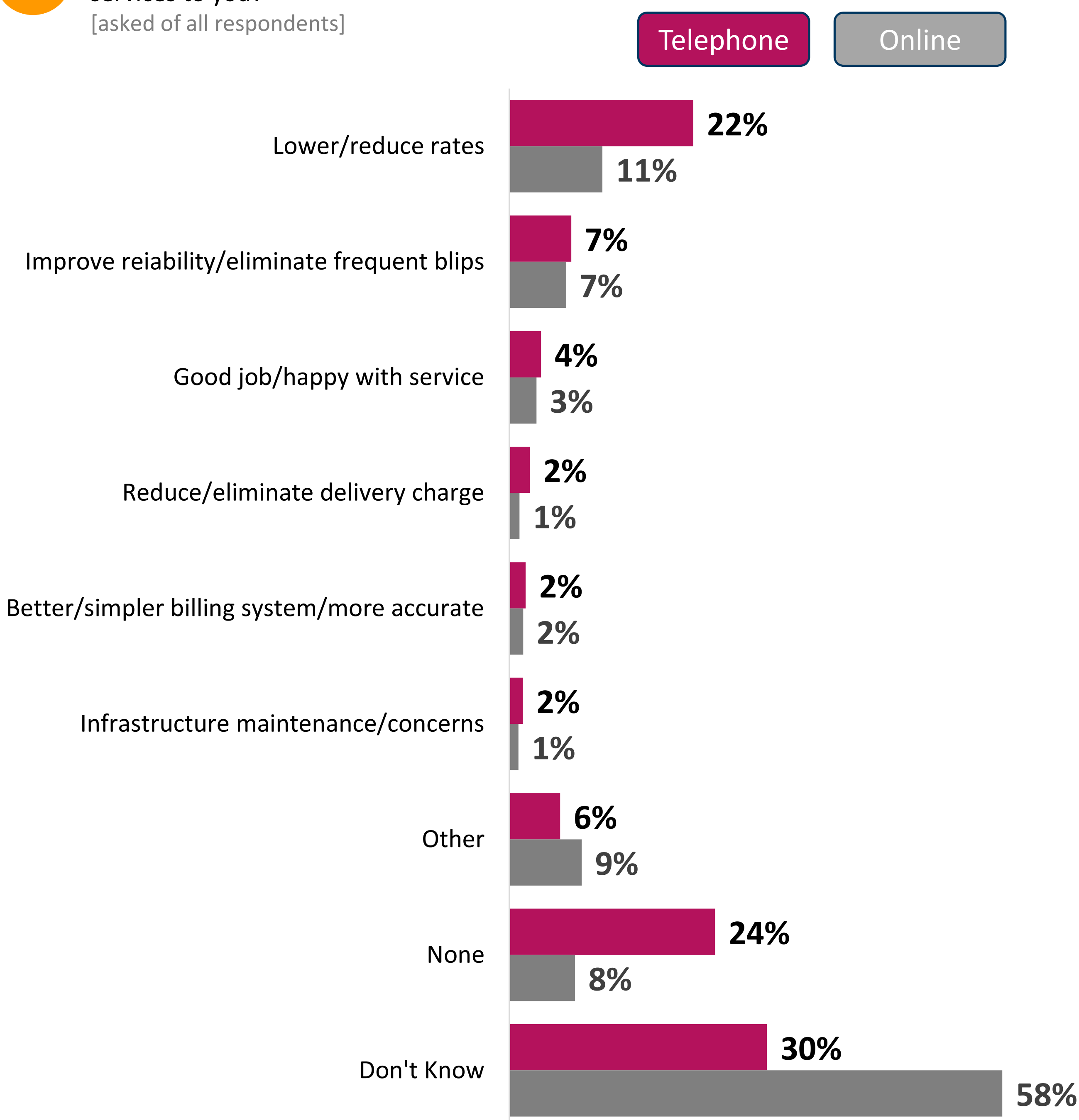
Suggestions for Improvement

Q And, is there anything in particular you would like Niagara Peninsula Energy to do to improve its services to you?

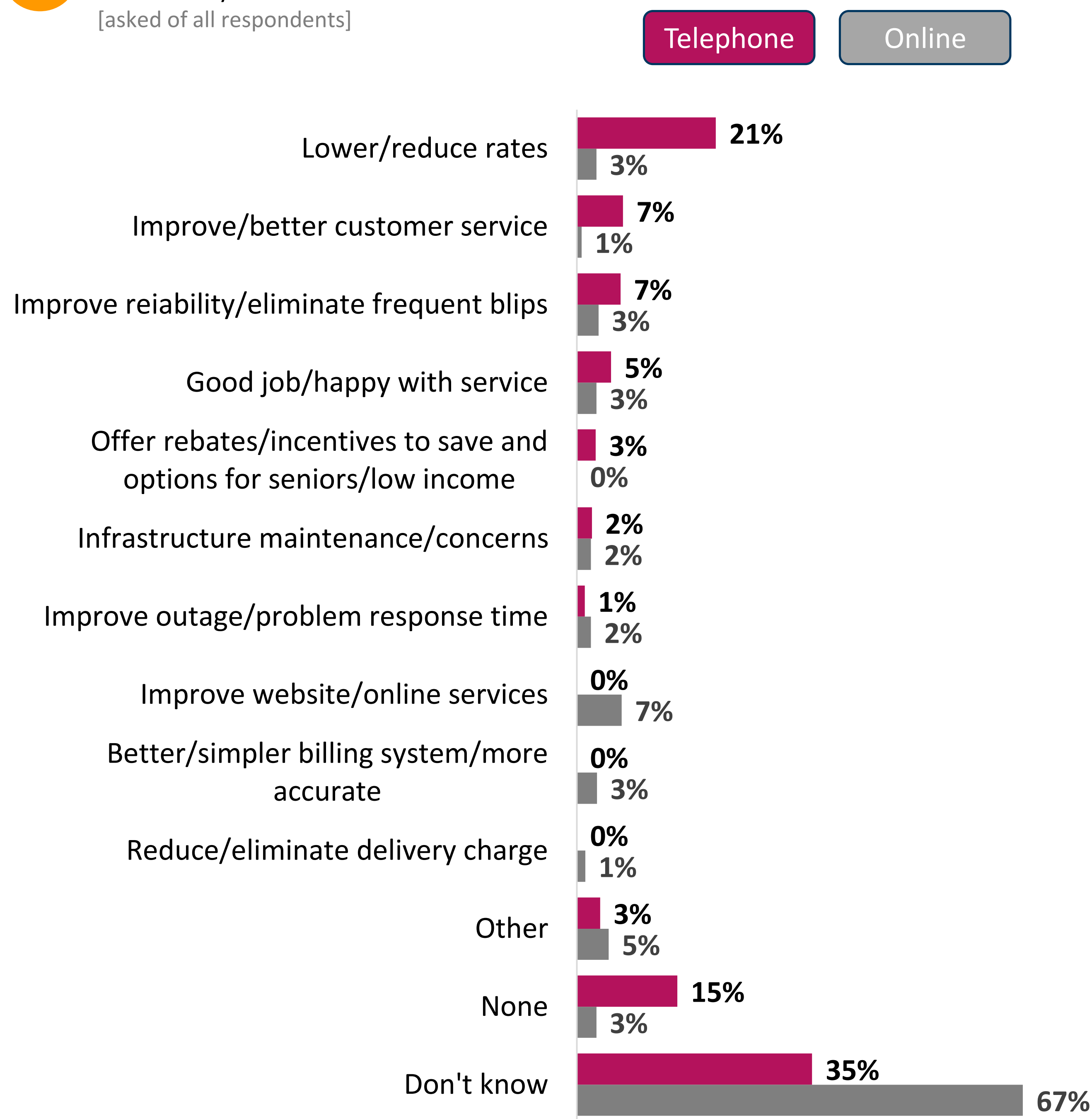
[asked of all respondents]



Ranked in order by telephone responses. “Other” represents responses codes <1%.

Suggestions for Improvement

Q And, is there anything in particular you would like Niagara Peninsula Energy to do to improve its services to you?
[asked of all respondents]



Ranked in order by telephone responses. “Other” represents responses codes <1%.

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Familiarity with Share of the Bill

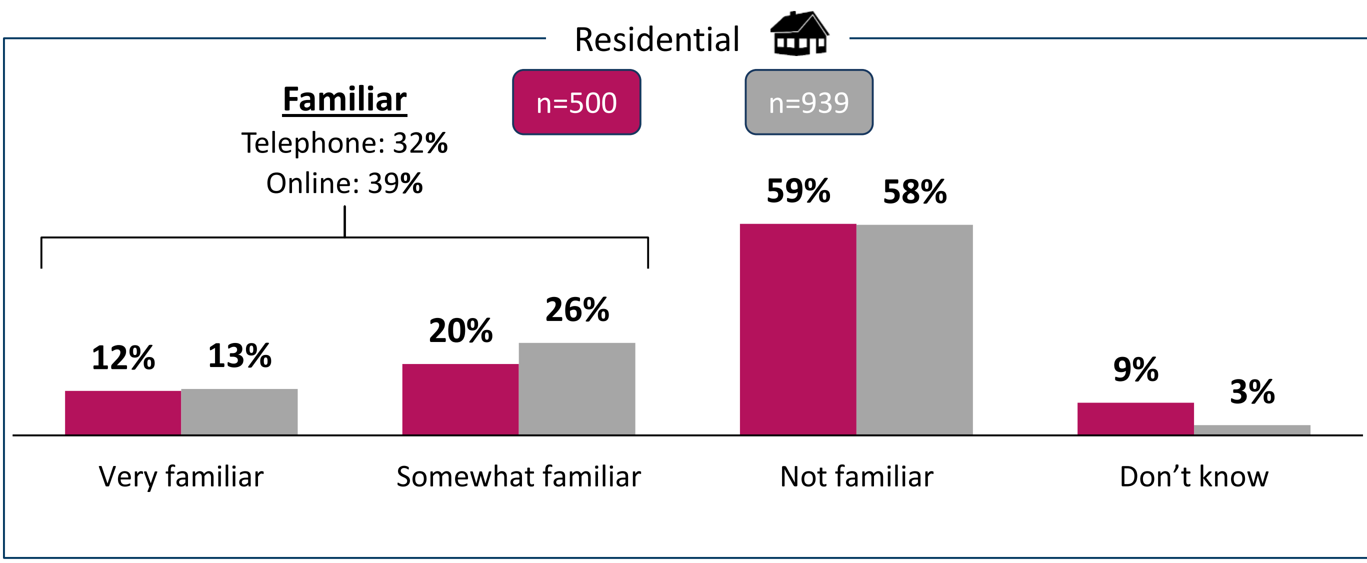
Preamble

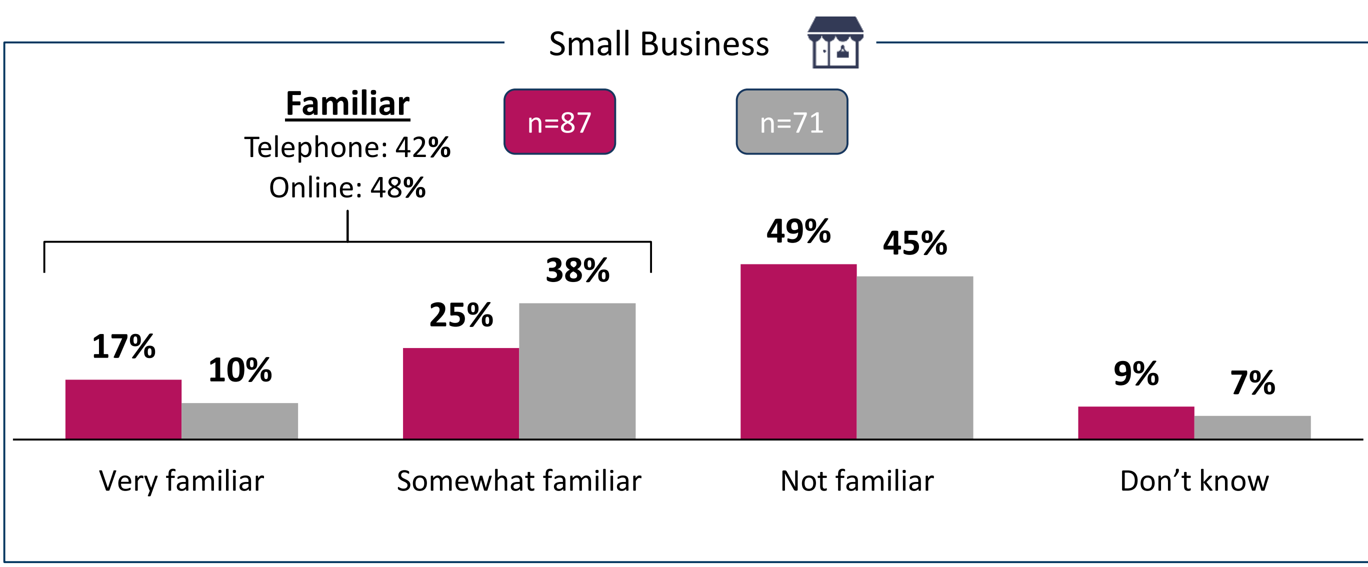
"While **Niagara Peninsula Energy** is responsible for collecting payment for the entire electricity bill, it keeps about **28%** of the average residential/small business customer's bill. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies."

Familiarity Niagara Peninsula Energy 's Share of the Bill

Q Before this survey, how familiar were you with the amount of your (organization's) electricity bill that went to **Niagara Peninsula Energy**? Would you say you were very familiar, somewhat familiar, not familiar or would you say you don't know?

Telephone | Online





Note: Sums added before rounding.

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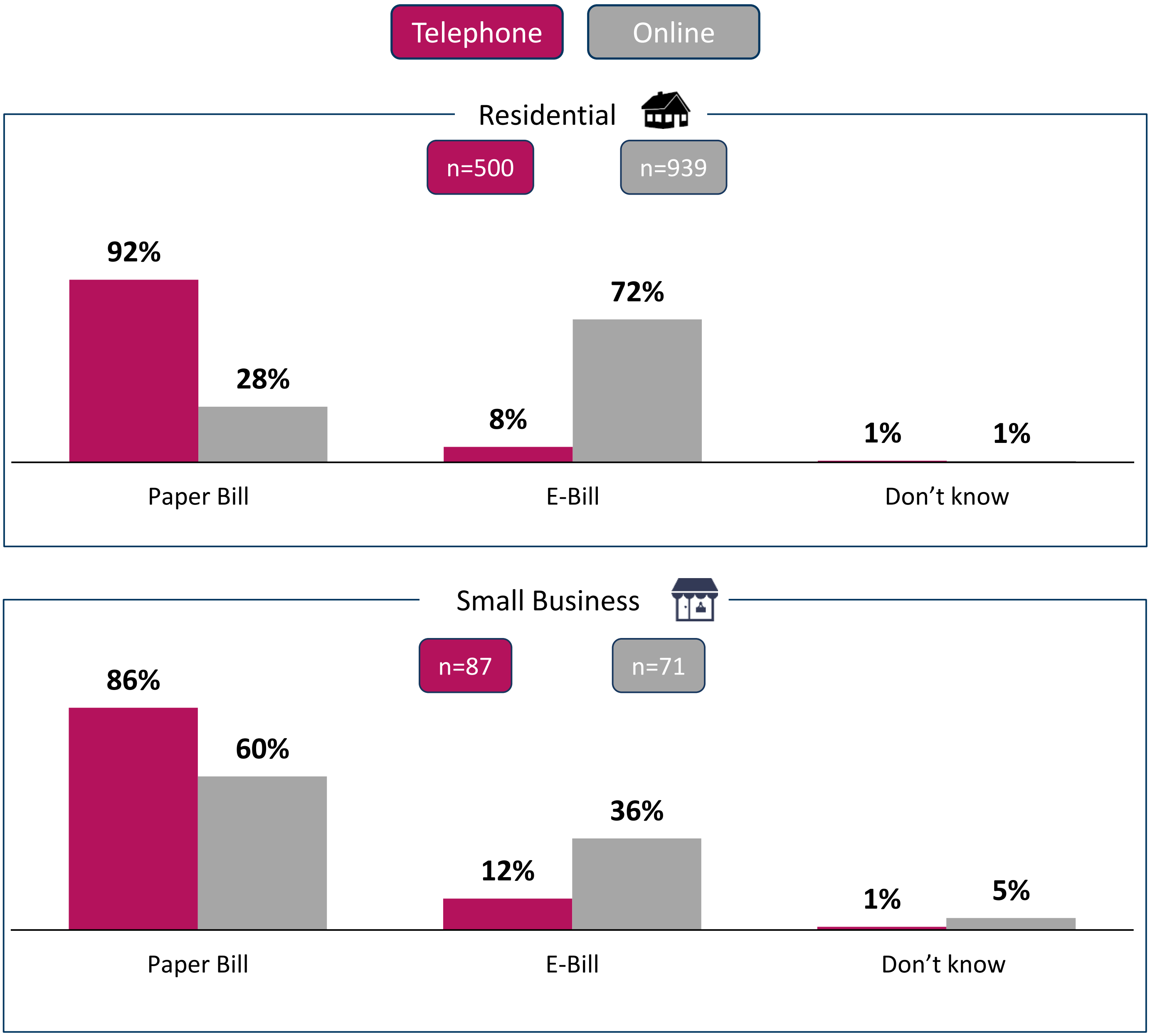
Bill Type

Q

In what format do you receive your monthly bill from **Niagara Peninsula Energy**?



Note: Sums added before rounding.

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Niagara Peninsula Energy
Customer Priorities

Customer Priorities

Preamble

"

Now, let's talk about our second topic – outcomes.

Everyday, ***Niagara Peninsula Energy*** *interacts with hundreds of its customer through multiple channels and touchpoints, including surveys, the call centre and social media.*

In a recent series of customer focus groups, a number of company goals were identified as priorities for ***Niagara Peninsula Energy****.*

"

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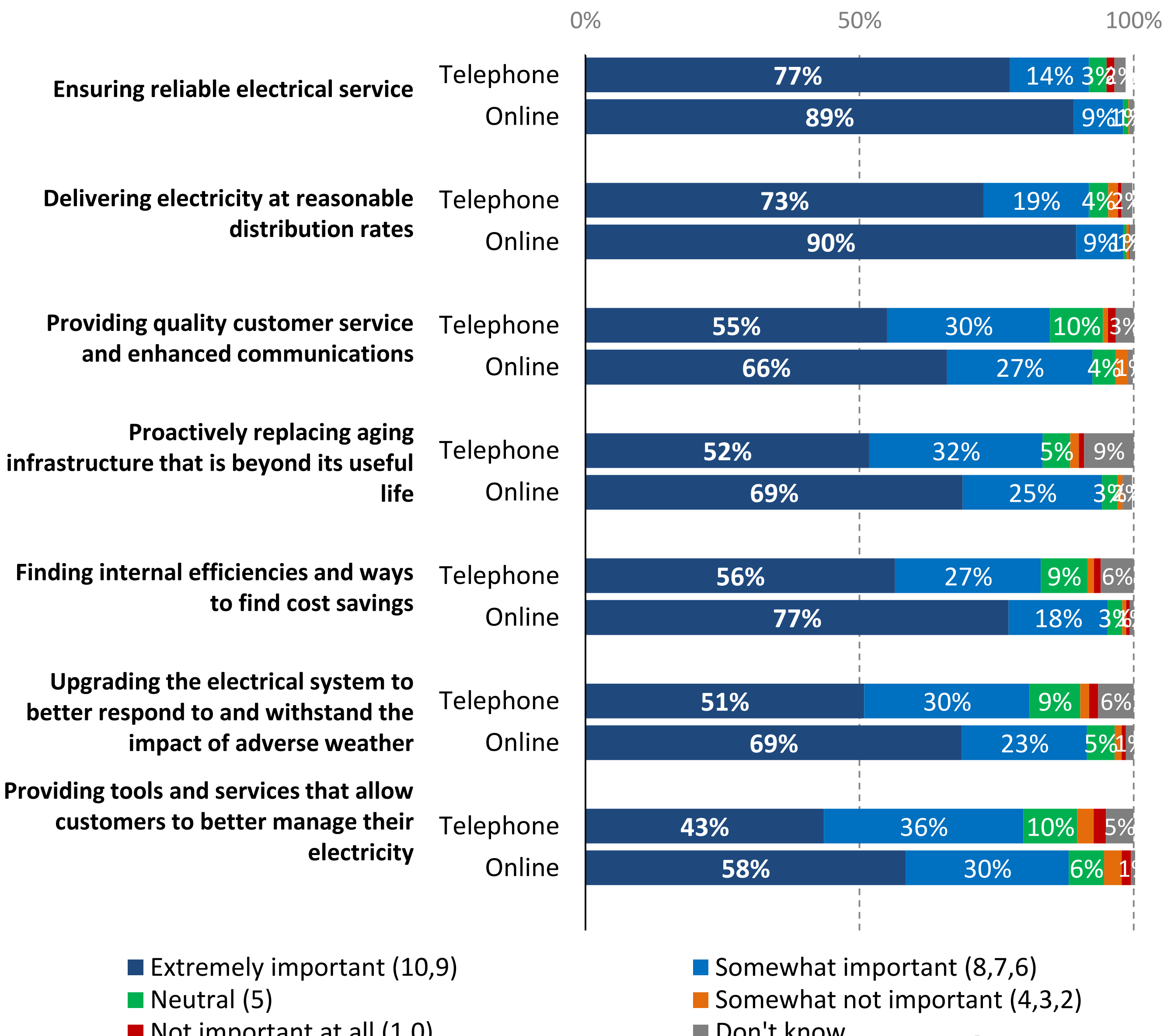
Residential Priorities

Overview of Importance Ratings

Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **Niagara Peninsula Energy** priorities to you as a customer.

[asked of all respondents, Telephone n=500; Online n=939]



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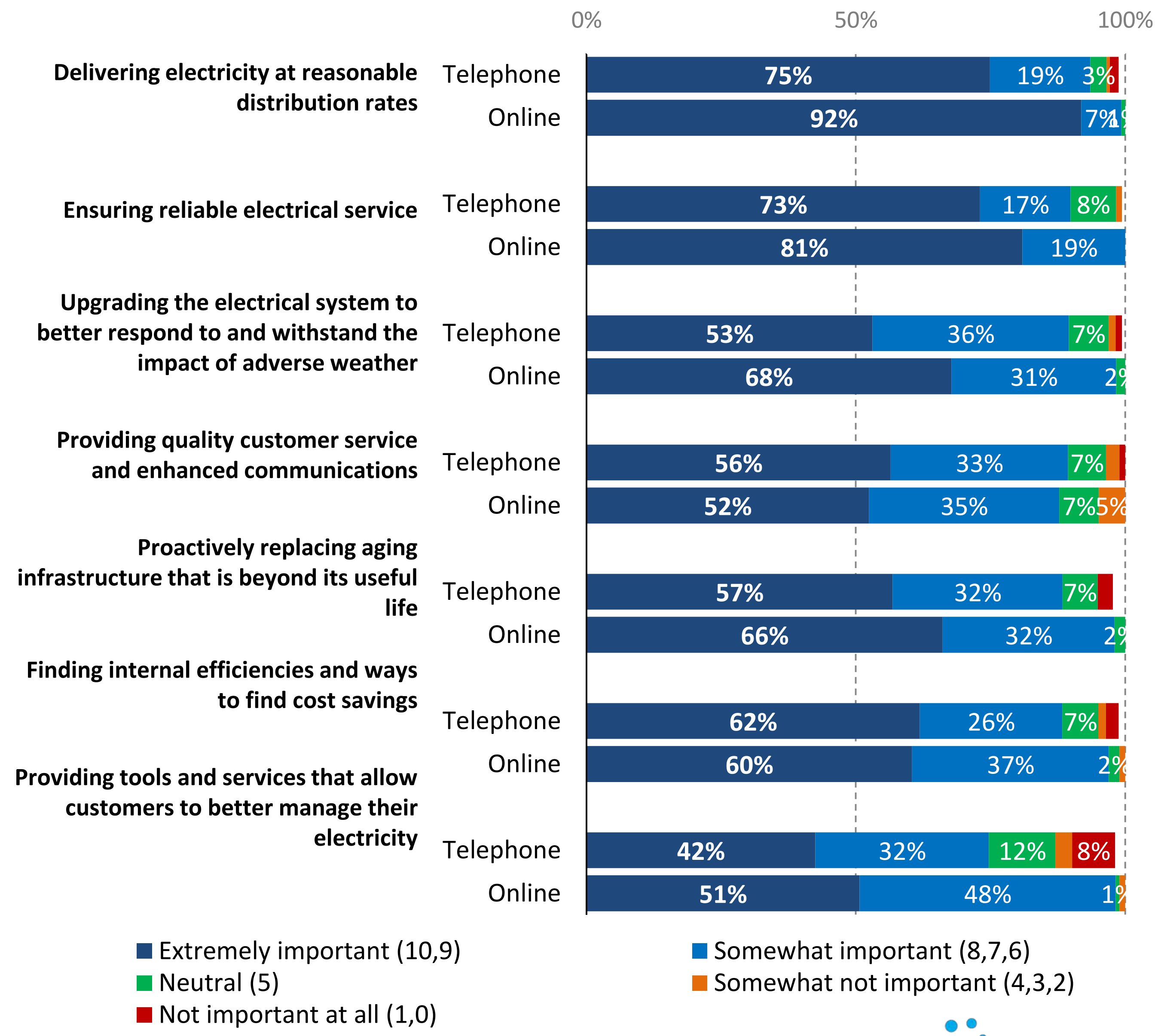
Small Business Priorities

Overview of Importance Ratings

Q

Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **Niagara Peninsula Energy** priorities to you as a customer.

[asked of all respondents, Telephone n=87; Online n=71]



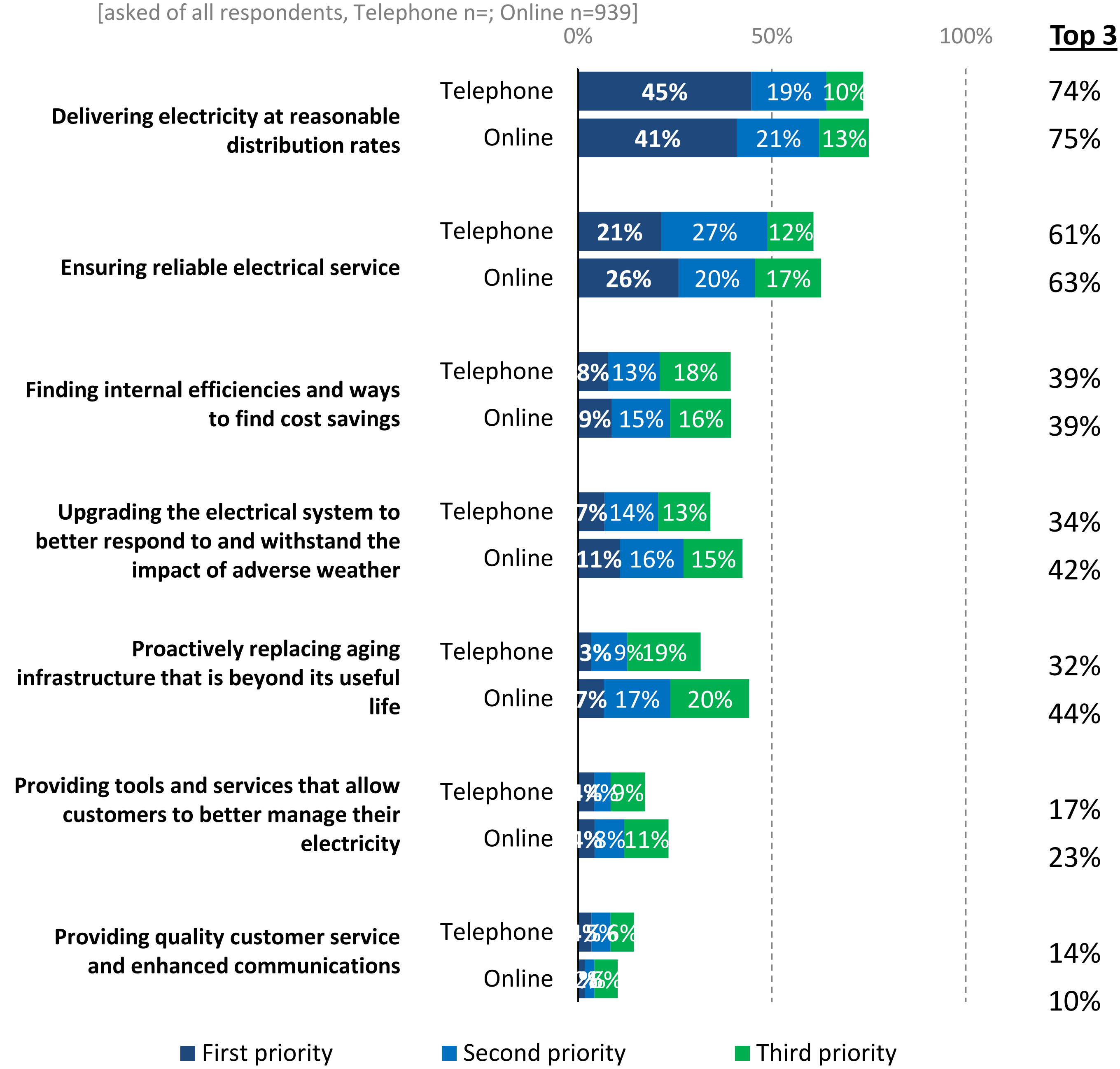
Residential Priority Rankings

Ranking the Top 3

Q

Now thinking of the priorities that we just discussed, please tell me which one is most important to you. What is the next most important priority you think **Niagara Peninsula Energy** should focus on? And what do you consider the third most important priority?

[asked of all respondents, Telephone n=; Online n=939]



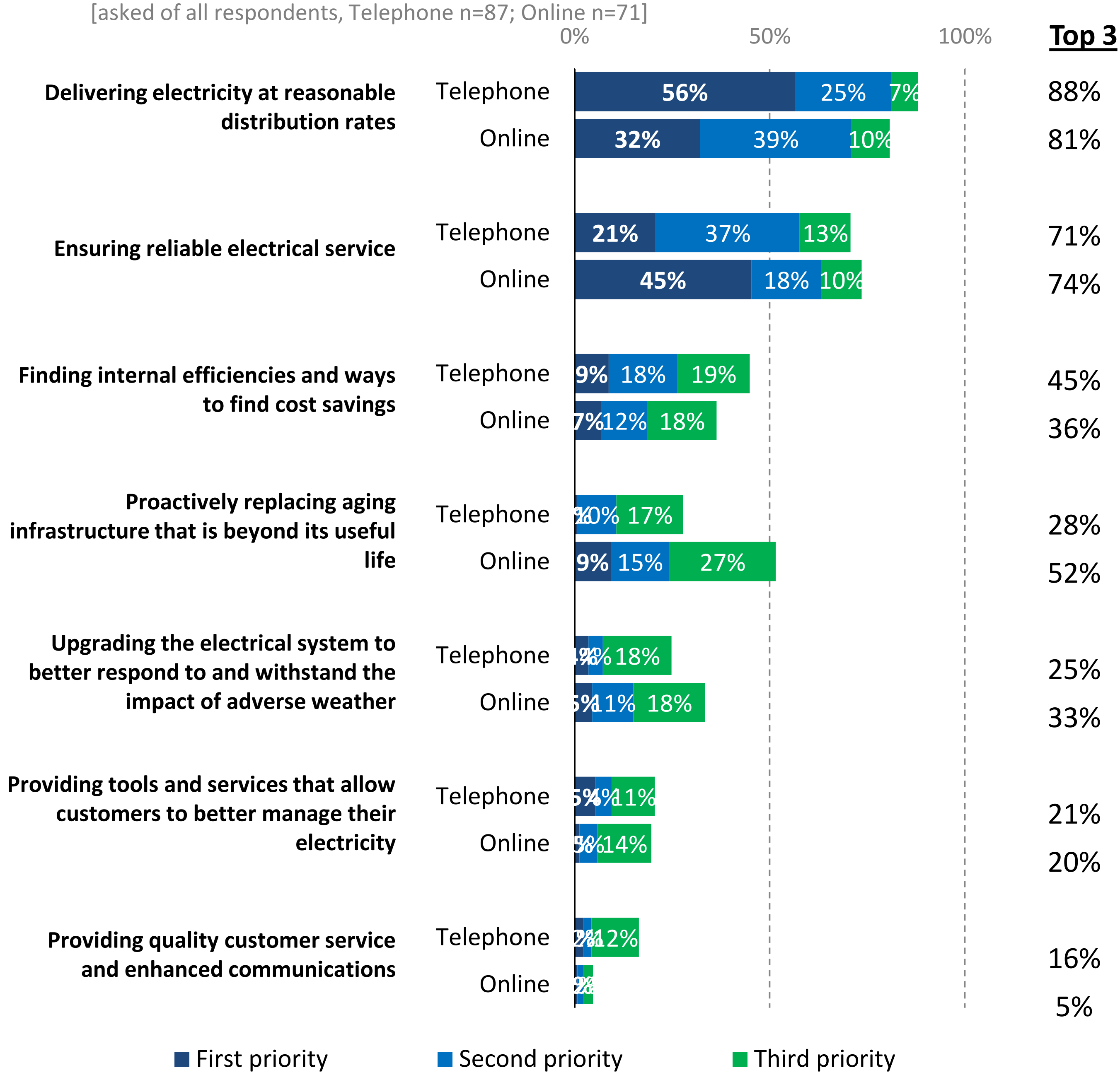
Note: Ranked in order by telephone responses.
"Don't know" not shown. Sums added before rounding.

Small Business Priority Rankings

Ranking the Top 3

Q Now thinking of the priorities that we just discussed, please tell me which one is most important to you. What is the next most important priority you think **Niagara Peninsula Energy** should focus on? And what do you consider the third most important priority?

[asked of all respondents, Telephone n=87; Online n=71]



Note: Ranked in order by telephone responses.
"Don't know" not shown. Sums added before rounding.

Residential

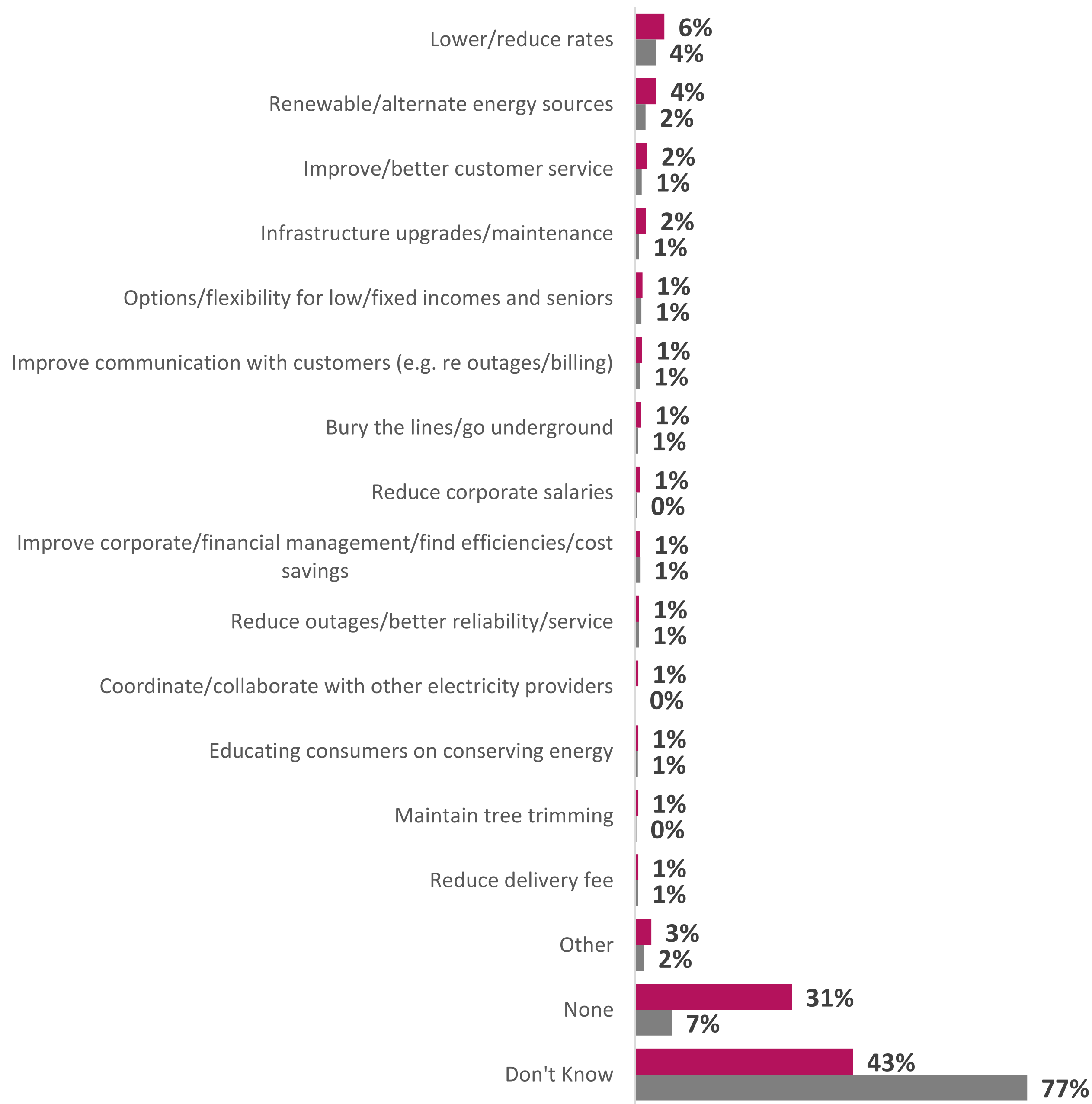
Other Important Priorities

Q

Can you think of any other important priorities that **Niagara Peninsula Energy** should be focusing on?

[asked of all respondents, Telephone n=500; Online n=939]

Telephone Online



Ranked in order by telephone responses. "Other" represents responses codes <1%.

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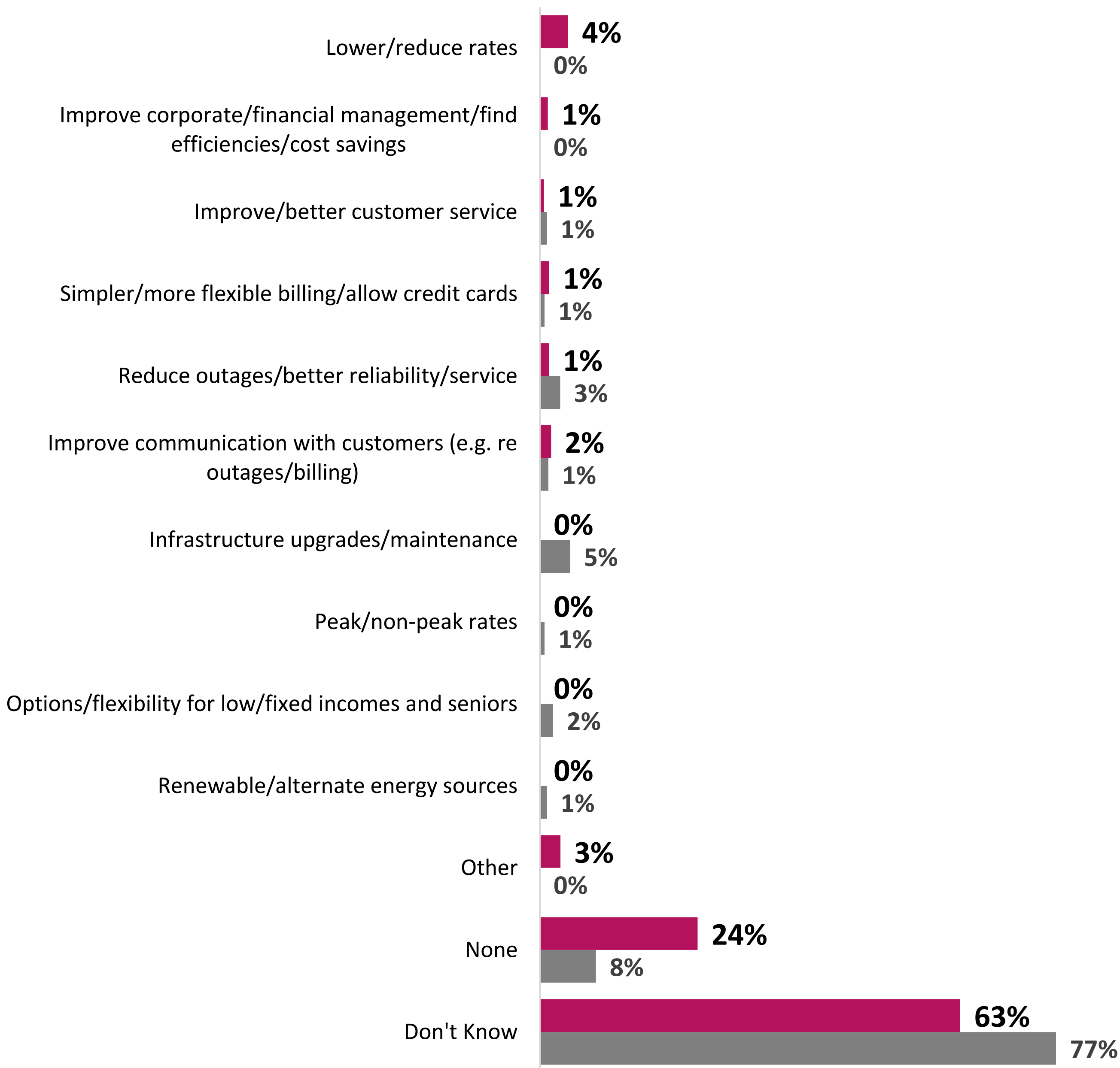
Other Important Priorities

Q

Can you think of any other important priorities that Niagara Peninsula Energy should be focusing on?

[asked of all respondents, Telephone n=; Online n=]

Telephone Online



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Ranked in order by telephone responses. “Other” represents responses codes <1%.

Reliability Outcomes

Reliability Experience

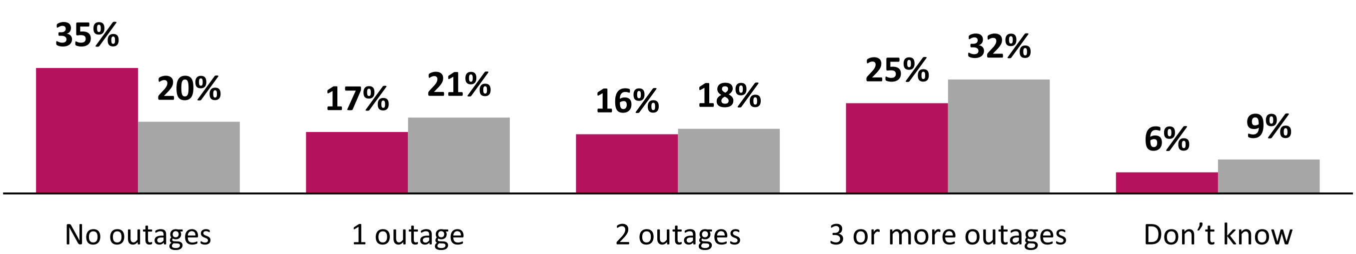
Q

Now, let's talk about the reliability of electricity service you/your organization receive. Have you experienced any power outages at **home/your organization in the past 12 months** which *lasted longer than one minute*? If so, approximately how many of these power outages did you/your organization experience?

Telephone | Online

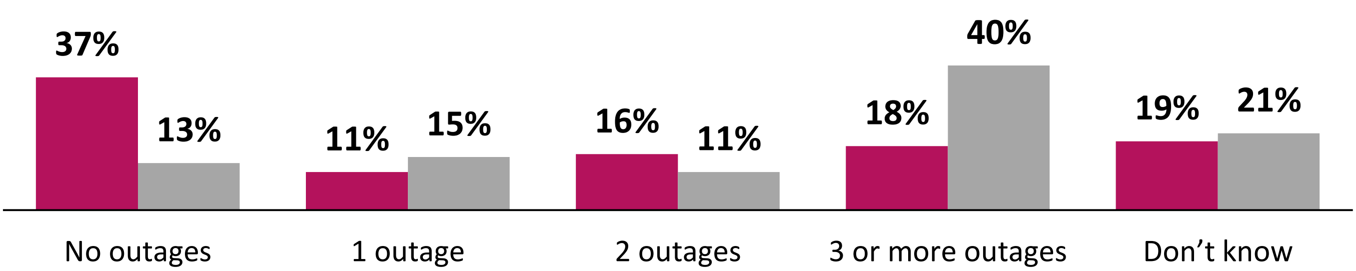
Residential

n=500 | n=939



Small Business

n=87 | n=71



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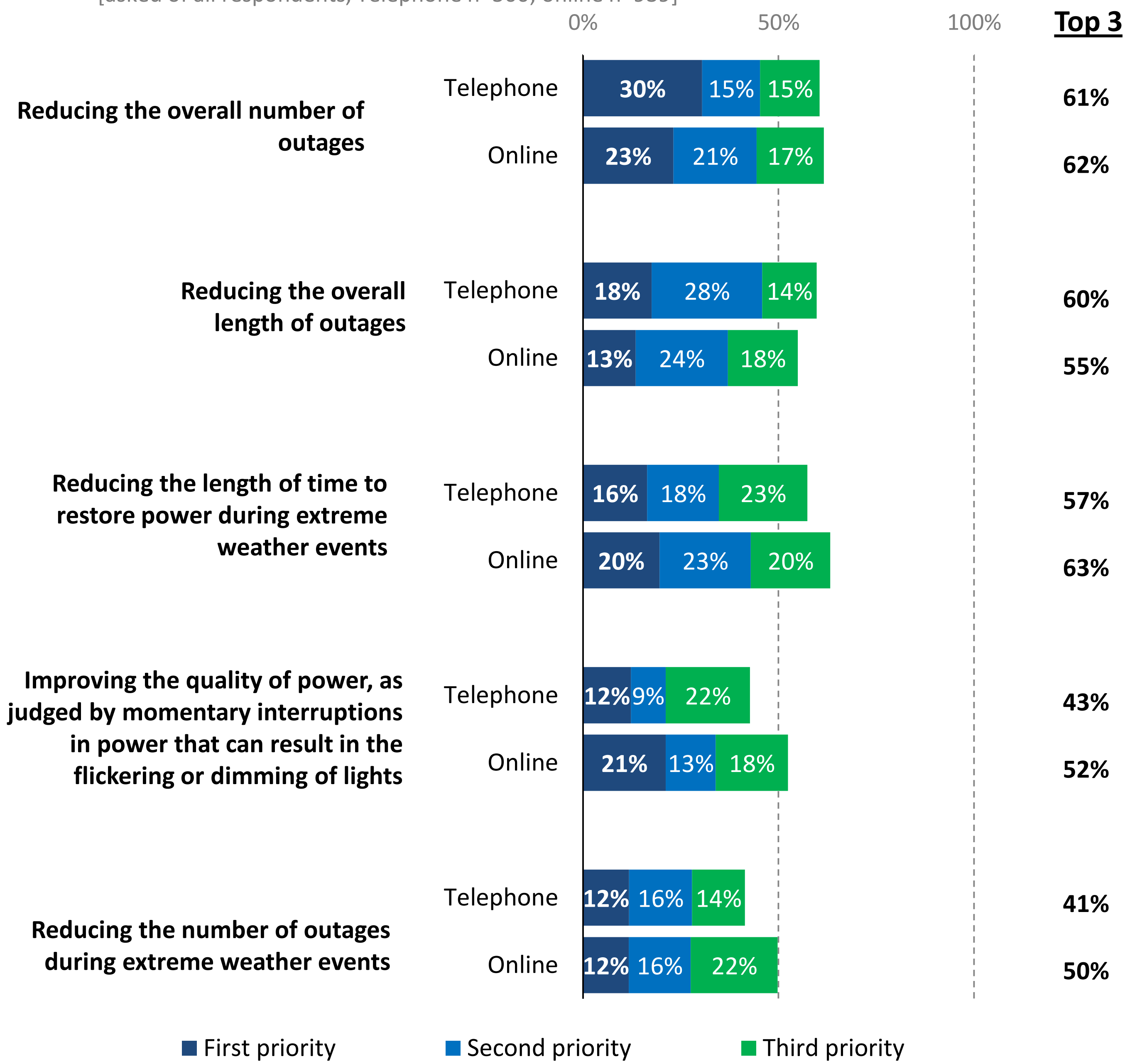
Note: 'Refused' not shown.

Residential

Ranking Reliability Outcomes

Ranking the Top 3

Q When it comes to reliability, there are a number of areas that **Niagara Peninsula Energy** could focus on. Among the following reliability outcomes, please tell me which one is most important to you. What is the next most important reliability outcome you think **Niagara Peninsula Energy** should focus on? And what do you consider the third most important reliability outcome?
[asked of all respondents, Telephone n=500; online n=939]



Note: Ranked in order by telephone responses.
"Don't know" not shown. Sums added before rounding.

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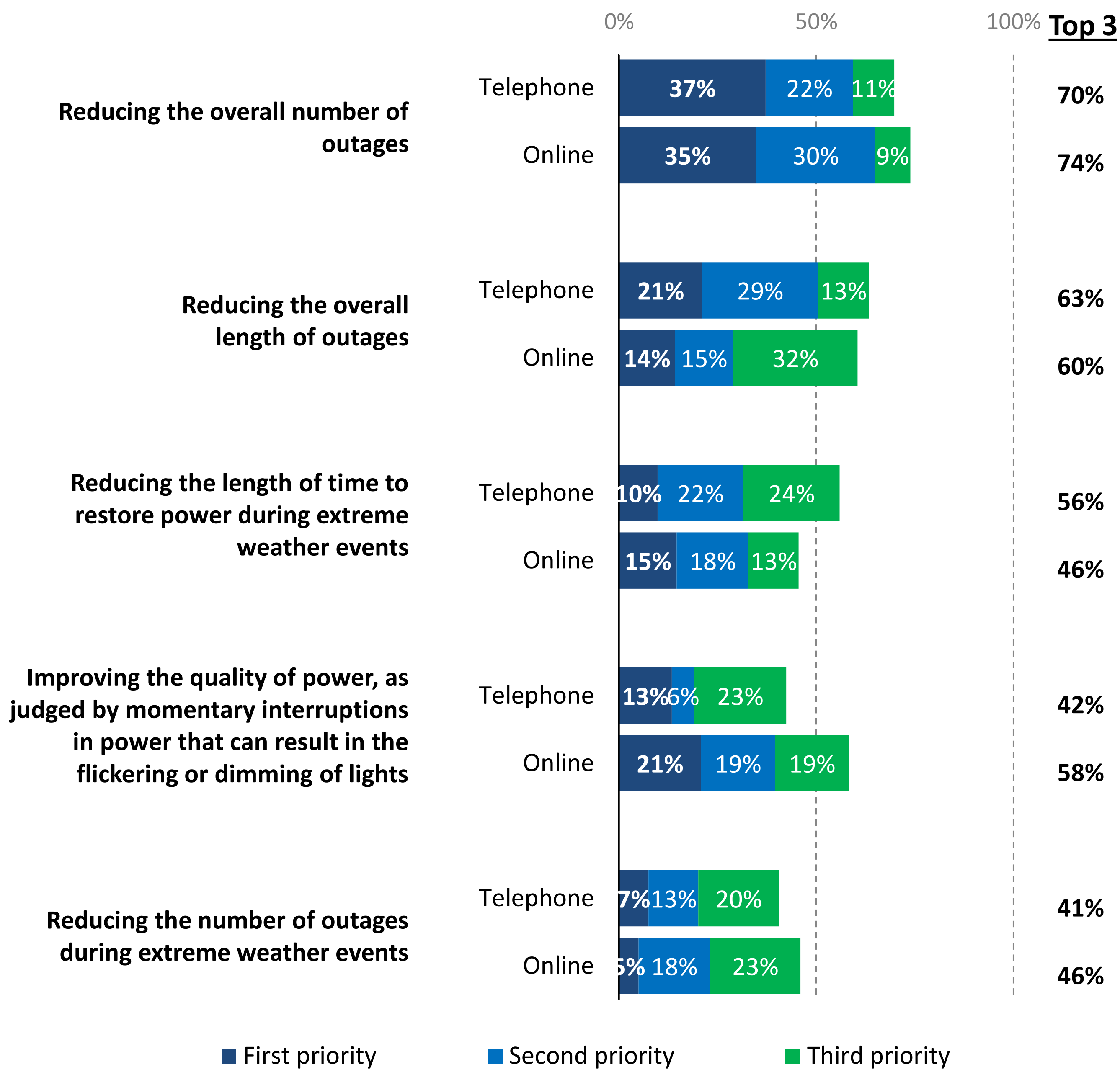
Small Business

Ranking Reliability Outcomes

Ranking the Top 3

Q

And when it comes to reliability, there are a number of areas that **Niagara Peninsula Energy** could focus on. Among the following reliability outcomes, please tell me which one is most important to you. What is the next most important priority you think **Niagara Peninsula Energy** should focus on? And what do you consider the third most important priority?
[asked of all respondents, Telephone n=87; Online n=71]



Note: Ranked in order by telephone responses.
"Don't know" not shown. Sums added before rounding.

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Investment Trade-Offs

Customer Priorities
Preamble

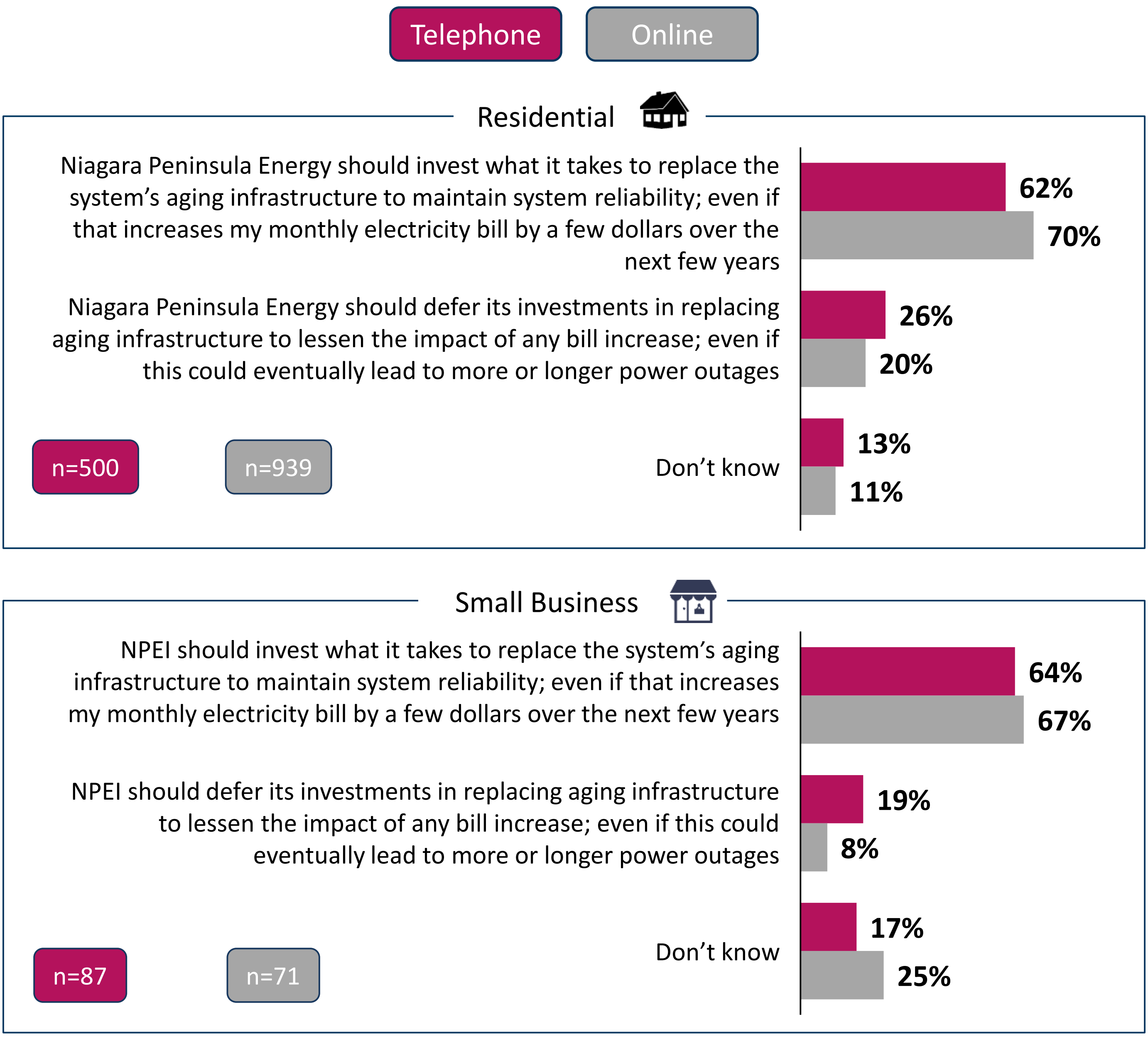
Now, let's turn to our final topic – investment trade-offs.

Niagara Peninsula Energy *is in the early stages of developing its investment plan far the next five years. While conversations with customers will continue over the next several months, the utility wants to find your preferences when it comes to finding the right balance between costs and other outcomes.*

There are four investment categories that we would like to discuss.

System Renewal

Q The first category focuses on projects that replace and restore aging electrical infrastructure, like overhead poles and underground cables. Regarding investments in aging infrastructure, which of the following statements best represents your point of view?



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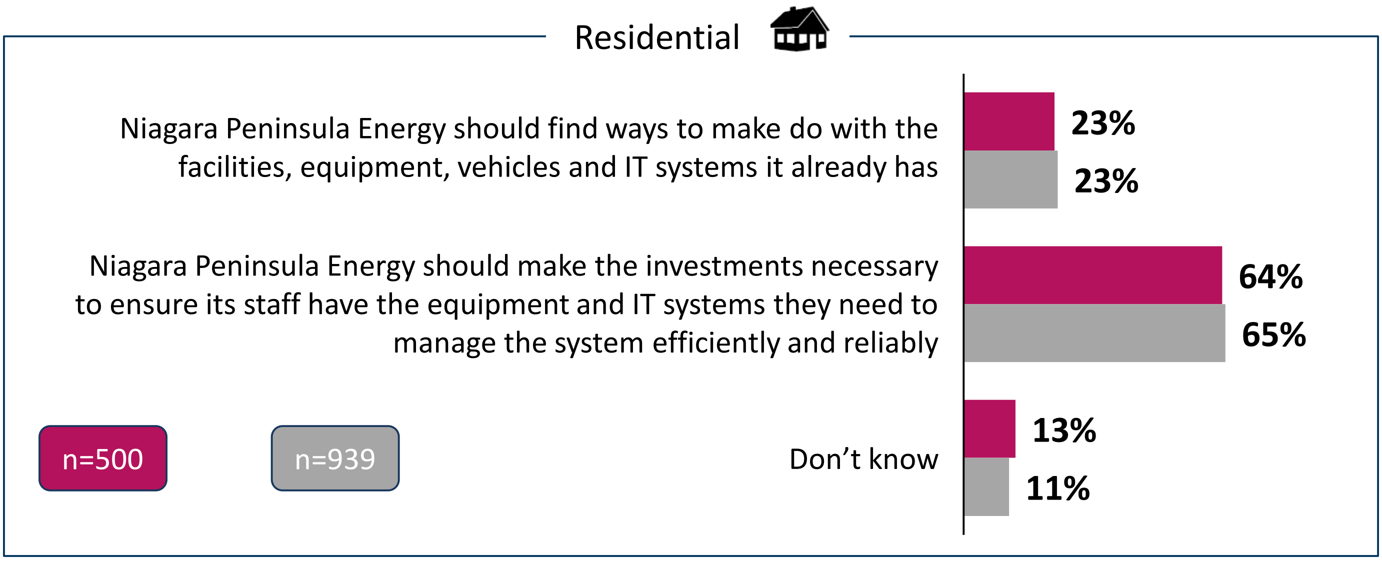
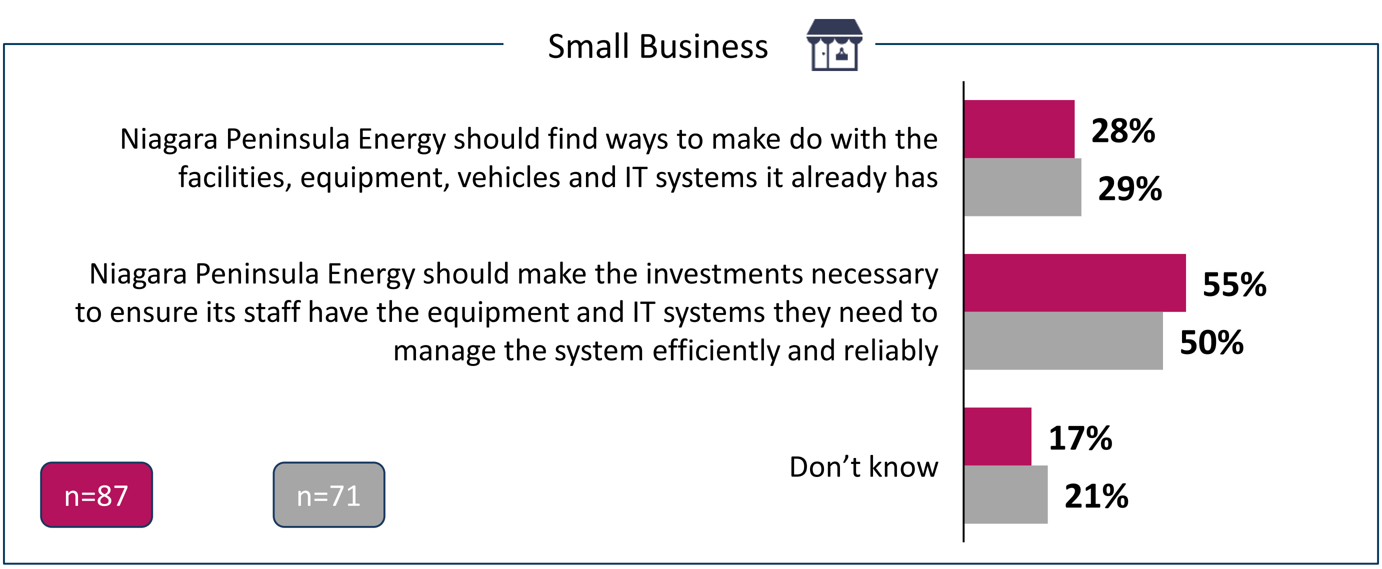
General Plant

Q The second category focuses on keeping **Niagara Peninsula Energy's** business running. This includes facilities to house staff and equipment, vehicles and tools to service equipment and IT systems to manage the system and customer information. Regarding these types of investments, which of the following statements best represents your point of view?

Telephone Online





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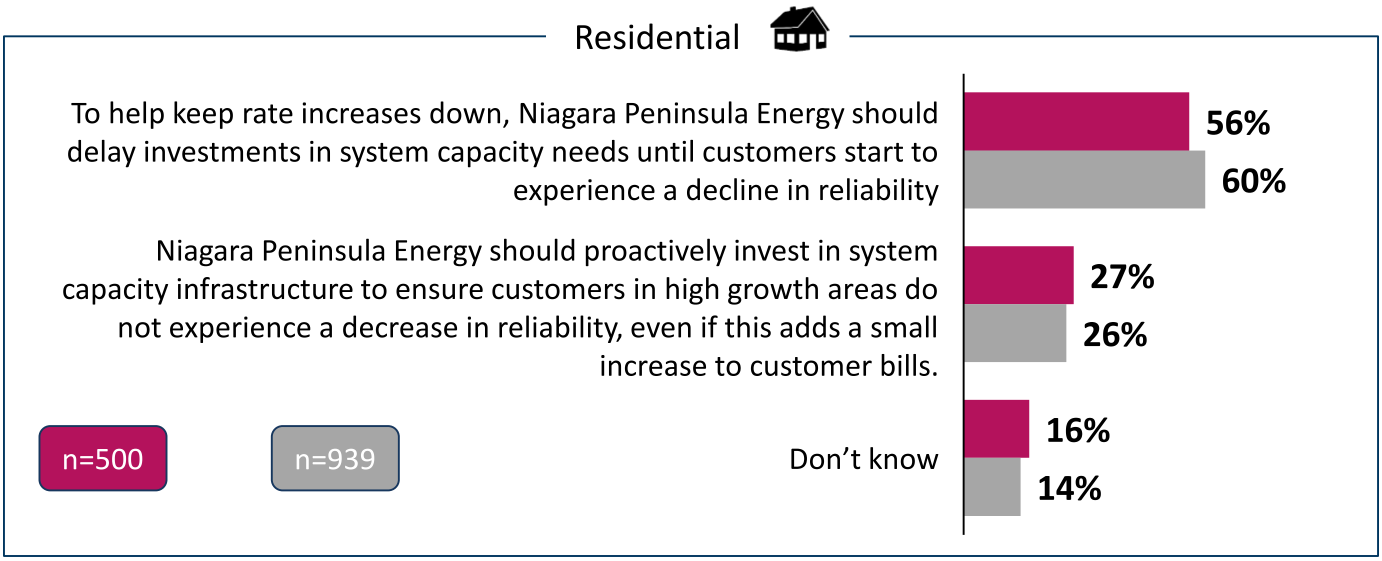
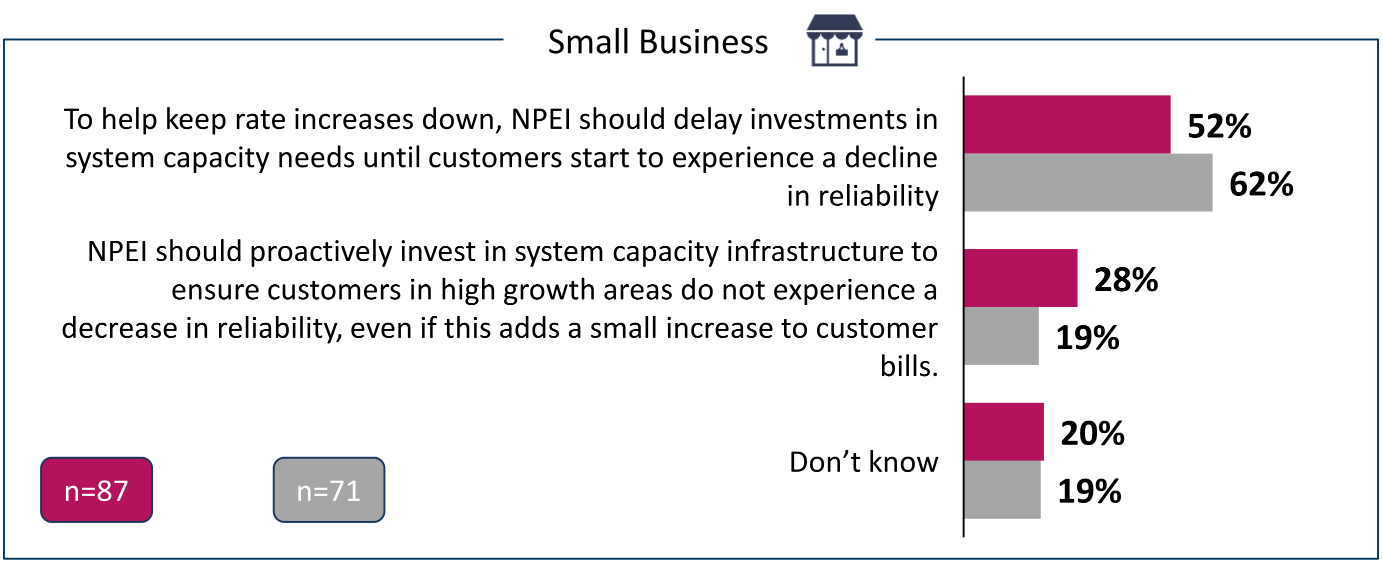
System Service

Q The third investment category focuses on growth and greater demand for electricity in various parts of **NPEI's** service territory. Increased demand for electricity puts pressure on existing electrical infrastructure. Eventually, further infrastructure investments are required to support increased demand for electricity. With this in mind, which of the following statements best represents your point of view?

Telephone Online



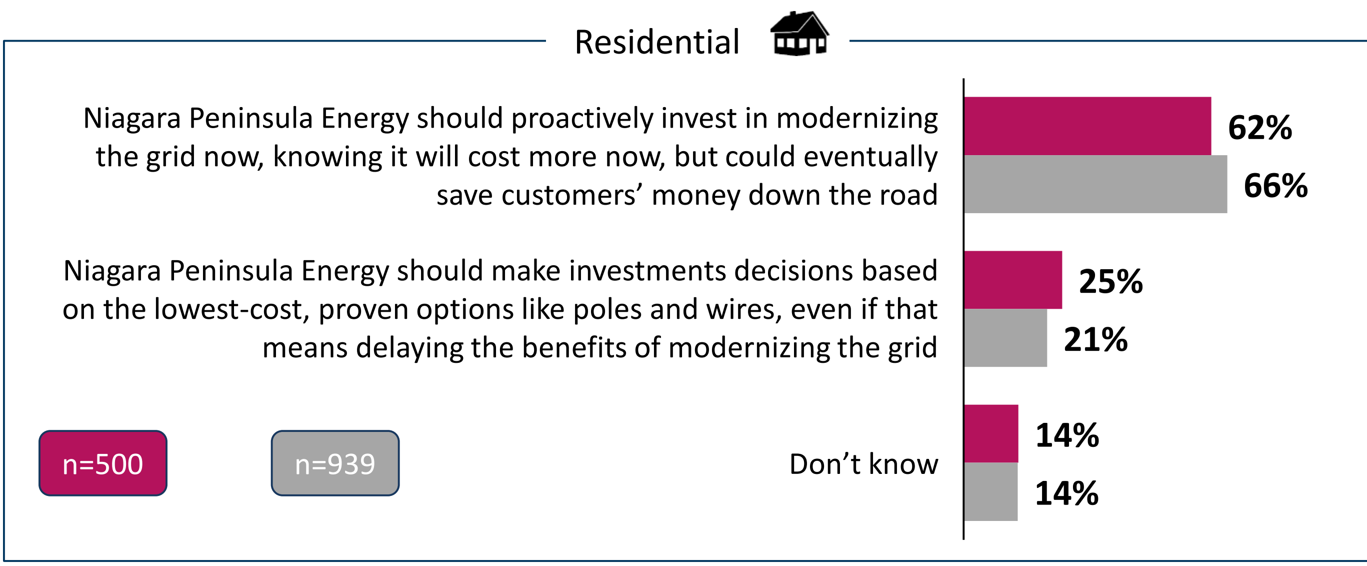


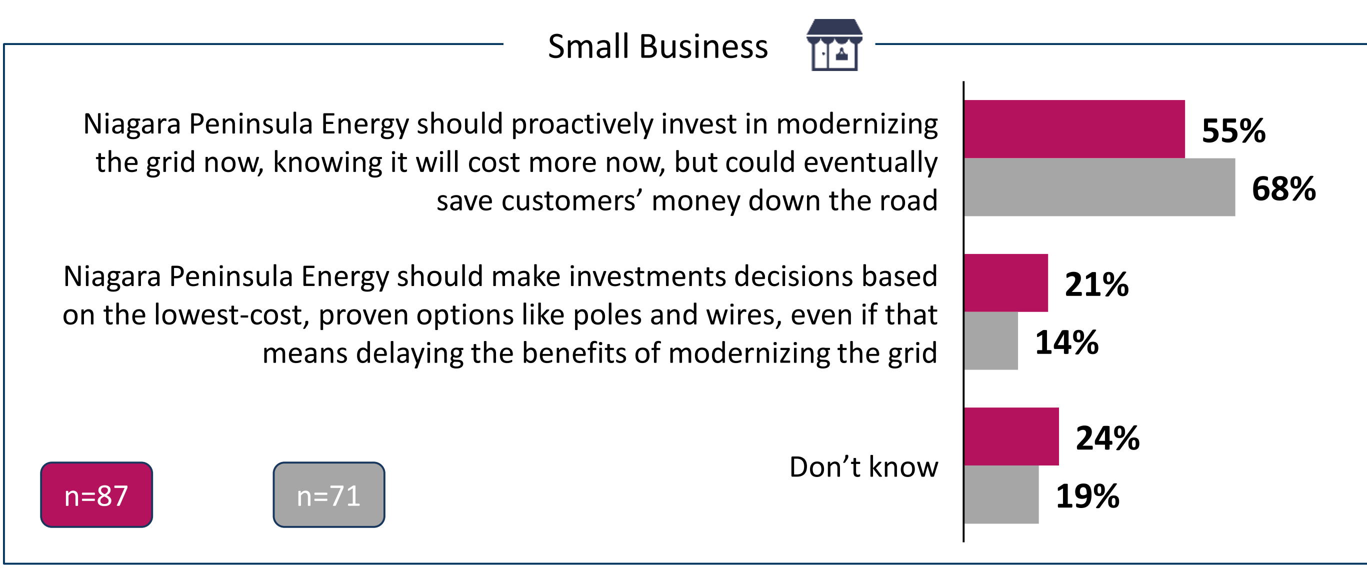
Note: 'Refused' not shown.

Grid Modernization

Q The final category is related to new technology that **Niagara Peninsula Energy** can implement, which may eventually save customers' money down the road. These types of investments could include electricity storage, solar energy or grid automation to more easily re-route power in the case of an outage. With this in mind, which of the following statements best represents your point of view?

Telephone | Online





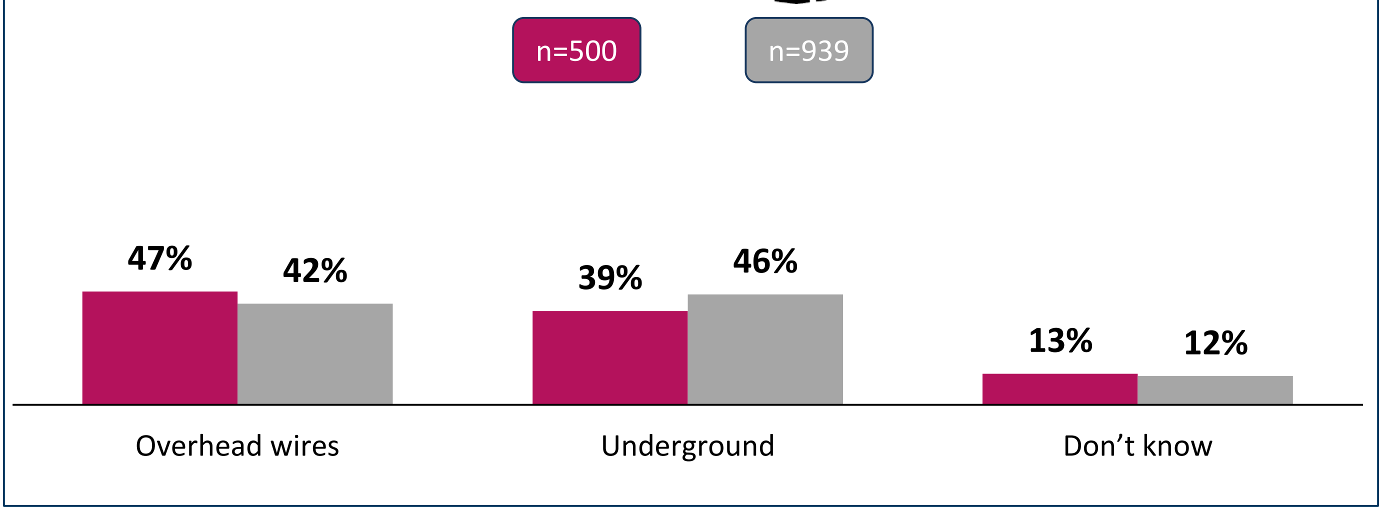
Note: 'Refused' not shown.

Connection Type

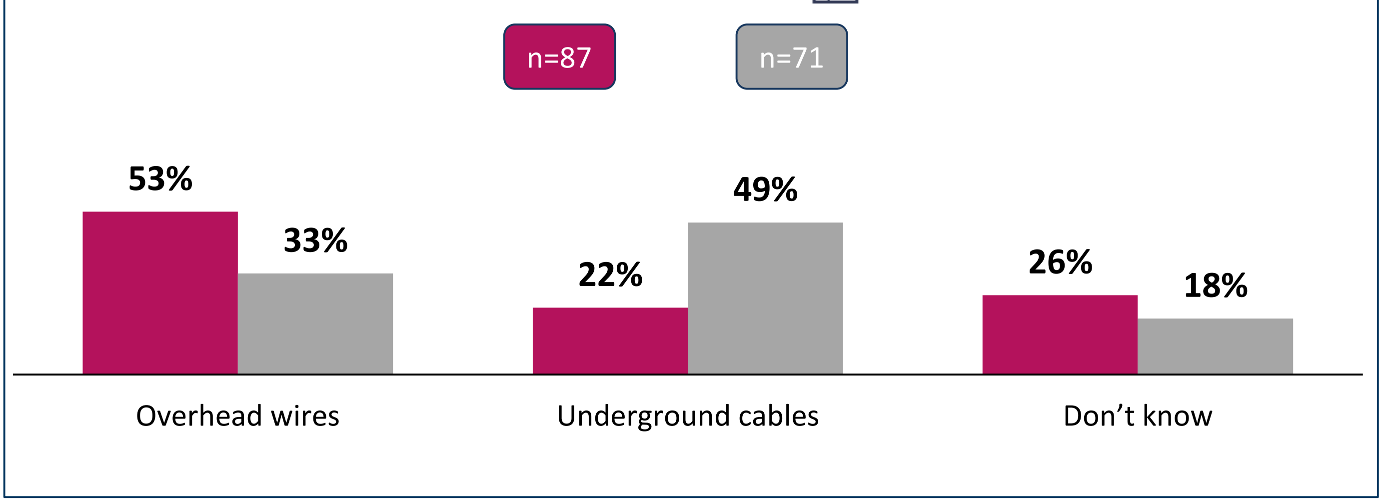
Q To the best of your knowledge, does your home receive electrical service via overhead wires, underground cables or would you say you don't know?

Telephone Online

Residential



Small Business



Note: 'Refused' not shown.

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Julian Garas
Senior Consultant
(t) 416-640-4133
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Customer Engagement (Appendix 3.0)

Needs and Preferences Planning Placemat

NPEI	Residential	Small business (GS<50kW)

What are customer needs?

The clear majority of NPEI residential and small business customers are satisfied with the current service they receive. When asked how NPEI can improve service, top responses for residential customers were "nothing", followed by "lower or reduce rates". Small business customers, however, placed greater emphasis on the lowering or reduction of rates.

	Residential	Small business (GS<50kW)
1st	Nothing	*Lower or reduce rates*
2nd	*Lower or reduce rates*	Nothing

What outcomes do customers prioritize?

Customers don't expect NPEI to just focus on one outcome. In fact, the majority of both residential and small business customers feel that almost all of the following outcomes are *extremely important* (with the exception to *providing tools to better manage electricity*).

- Ensuring reliable electrical service
- Delivering electricity at reasonable distribution rates
- Providing quality customer service and enhanced communications
- Proactively replacing aging infrastructure that is beyond its useful life
- Finding internal efficiencies and ways to find cost savings
- Upgrading the electrical system to better respond to and withstand the impact of adverse weather

Among competing outcomes, *price*, *reliability*, and *finding internal cost efficiencies* are the top three priorities for both residential and small business customers. When ranked relative to other priorities, NPEI customers see price as the top outcome that the utility should focus on.

	Residential	Small business (GS<50kW)
Top Priority	Delivering electricity at reasonable distribution rates	Delivering electricity at reasonable distribution rates
2nd Priority	Ensuring reliable electrical service	Ensuring reliable electrical service
3rd Priority	Finding internal efficiencies and ways to find cost savings	Finding internal efficiencies and ways to find cost savings

What reliability outcomes do customers prioritize?

Residential and small business customers have consistent priorities when it comes to reliability. Reducing the overall number of outages, the overall length of outages, and improving restoration time are the top three priorities for both rate classes.

	Residential	Small business (GS<50kW)
Top Priority	Reducing the overall number of outages	Reducing the overall number of outages
2nd Priority	Reducing the overall length of outages	Reducing the overall length of outages
3rd Priority	Reducing the length of time to restore power during extreme weather events	Reducing the length of time to restore power during extreme weather events

	Residential	Small business (GS<50kW)

What investment trade offs do customers value most?

While keeping price at a reasonable and affordable level is an important priority for customers, the majority feel that investing in the grid to maintain reliability, is preferable to deferring investments to keep bills low.

The majority of residential and small business customers are willing to consider paying more to invest in maintaining reliability, equipping staff with equipment and IT systems, proactively investing in system capacity, and modernizing the grid knowing that it could eventually save money.

Further, the majority of customers support proactive investment in both system capacity and grid modernization. Relative to other trade offs support for investment in system capacity is least intense.

Replacing Aging Infrastructure (System Renewal)

The majority of residential and small business customers are supportive of NPEI making investments in aging infrastructure in order to maintain reliability, even if that results in small rate increases. This option is most strongly supported by small business customers, when compared to other trade offs.

% of customers who say NPEI should invest what it takes to maintain reliability

	Residential	Small business (GS<50kW)
Invest to maintain reliability	**62%**	**64%**

Keeping the Business Running (General Plant)

The majority of residential and small business customers support NPEI making the necessary investments to ensure its staff have the equipment and IT systems that are needed to manage the system efficiently and reliably. This option is most strongly supported by residential customers, when compared to other trade offs.

% of customers who say NPEI should make investments necessary in general plant

	Residential	Small business (GS<50kW)
Invest what is necessary	**64%**	**55%**

Proactive Investments in System Capacity (System Service)

A slim majority of residential and small business customers are more inclined to say that NPEI should proactively invest in system capacity infrastructure to ensure customers in high growth areas do not experience a decrease in reliability.

Relative to other trade offs, this option has the weakest level of support.

% of customers who say NPEI should proactively invest in system capacity

	Residential	Small business (GS<50kW)
Proactively invest in system capacity	**56%**	**52%**

Proactive Investments in Grid Modernization (New Technology)

The majority of residential and small business customers are supportive of NPEI proactively investing in modernizing the grid now, knowing it will cost more now, but could eventually save customers money down the road.

% of customers who say NPEI should proactively invest in modernizing the grid now

	Residential	Small business (GS<50kW)
Proactively invest in modernization	**62%**	**55%**

Customer Engagement Methodology

These findings are based on two telephone surveys conducted by Innovative Research Group among residential and GS<50kW customers.

- Field Dates: July 9 – 26, 2019
- Sample Size: n=505 residential and n=87 GS<50kW (unweighted)

Additional Information

For more information on using this document or customer engagement results, please contact:

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Telephone Reference Survey

Residential Version

July 2019

Prepared by:

Innovative Research Group, Inc.
www.innovativeresearch.ca

Vancouver
888 Dunsmuir Street, Suite 350
Vancouver BC | V6C 3K4

Toronto
56 The Esplanade, Suite 310
Toronto, Ontario | M5E 1A7

A. SCREENING AND QUALIFICATIONS

Introduction

Hello, my name is _____________ and I'm calling from **Innovative Research Group** on behalf of **Niagara Peninsula Energy**, your local electricity distributor.

Innovative Research Group is a national public opinion research firm. **We're seeking your input on choices that may affect the service you receive from Niagara Peninsula Energy.**

We are simply interested in hearing your opinions – no attempt will be made to sell you anything.

A1. Do you have about **7 minutes** to answer some survey questions? All your responses will be kept strictly confidential.

1	Yes	**[continue]**
2	No – NOT PRIMARY BILL PAYER	**[go to TRANSFER-1]**
3	No – BAD TIME	**ARRANGE CALLBACK**
4	No – HARD REFUSAL	**[Terminate]**

MONIT
This call may be monitored or audio taped for quality control and evaluation purposes.

1 PRESS TO CONTINUE

CELL. Are you currently operating a car, truck or other motor vehicle?

1	YES	ARRANGE CALLBACK
2	NO	[continue to A2]
98	Refused – LOG (THANK AND TERMINATE)	**[Terminate]**

A2. Are you the person primarily responsible for paying the electricity bill in your household?

1	Yes – I pay the bill	[continue to A3]
2	Yes – shared responsibility	[continue to A3]
3	No	[go to TRANSFER-1]
98	Don't know (**DNR**)	**[Terminate]**

TRANSFER-1

Can I speak with the person in your household who usually pays the electricity bill?

1	Yes	[**BACK TO *INTRO***]
2	No – NOT AVAILABLE/BAD TIME	[ARRANGE CALLBACK]
3	No – HARD REFUSAL	[**Terminate**]
98	Don't know (**DNR**)	[**Terminate**]

A3. Can you confirm that your household receives an electricity or hydro bill from **Niagara Peninsula Energy**?

1	Yes	[**continue**]
2	No	[**Terminate**]
98	Don't know (**DNR**)	[**Terminate**]

GENDER **Note gender by observation:**

1	Male
2	Female

A4. For statistical purposes, can you please indicate which age category you fall in? Is that … [**READ LIST**]

01	Younger than 18	**DNR**
02	18 to 24	
03	25 to 34	
04	35 to 44	
05	45 to 54	
06	55 to 64	
07	65 to 74	
08	75 or older	
99	Refused	**READ**: For this survey we need to identify customers' age. **IF STILL REFUSE**: THANK & TERMINATE

B. INTRODUCTION AND CORE MEASURE

[PREAMBLE]

Today I want to talk about **Niagara Peninsula Energy** and the local electricity system in your community.

There are three topics I would like to discuss:

- First, we will talk about your experience with Niagara Peninsula Energy.
- Second, we will talk about the outcomes that matter most to you; and
- And finally, we will talk about some trade-offs in planning future investments.

First, let's talk about your experience.

While you might have multiple accounts with Niagara Peninsula Energy, for this survey, we want you to think about your overall experience as a residential customer.

The following questions are about **Niagara Peninsula Energy's** distribution system. This is the system that takes the electricity from high-voltage transmission towers and brings it to your home through a network of wires, poles and other equipment that is owned and operated by **Niagara Peninsula Energy**.

B5. How familiar are you with **Niagara Peninsula Energy**, which operates the electricity distribution system in your community?

Would you say you are *very familiar*, *somewhat familiar*, *not familiar* or would you say you *don't know*?

01	Very familiar	
02	Somewhat familiar	
03	Not familiar	
98	Don't know	
99	Refused [**DO NOT READ**]	

B6. Thinking specifically about the services provided to you and your community by **Niagara Peninsula Energy**, overall, how satisfied or dissatisfied are you with the services that you receive?

Would you say you are *very satisfied, somewhat satisfied, neither satisfied nor dissatisfied, somewhat dissatisfied, very dissatisfied or would you say you don't know*?

01	Very satisfied	
02	Somewhat satisfied	
03	Neither satisfied or dissatisfied	
04	Somewhat dissatisfied	
05	Very dissatisfied	
98	Don't know	
99	Refused [**DO NOT READ**]	

B7. And, is there anything in particular you would like **Niagara Peninsula Energy** to do to improve its services to you? [**OPEN**]

98	Don't know	
99	Refused [**DO NOT READ**]	

B8. While **Niagara Peninsula Energy** is responsible for collecting payment for the entire electricity bill, it keeps about **28%** of the average residential customer's bill. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.

Before this survey, how familiar were you with the amount of your electricity bill that went to **Niagara Peninsula Energy**? Would you say you were *very familiar, somewhat familiar, not familiar or would you say you don't know?*

01	Very familiar
02	Somewhat familiar
03	Not familiar
98	Don't know

Bill Type

B9. And do you receive your monthly bill from Niagara Peninsula Energy as a **paper bill** or an **electronic bill**?

01	Paper Bill	
02	E-Bill	
98	Don't know [**DO NOT READ**]	

C. CUSTOMER PRIORITIES

Now, let's talk about our second topic – outcomes.

Every day, **Niagara Peninsula Energy** interacts with hundreds of its customers through multiple channels and touchpoints, including surveys, the call centre, and social media.

In a recent series of customer focus groups, a number of company goals were identified as priorities for **Niagara Peninsula Energy**.

Using a scale from 0 to 10, where _0 means not important at all_ and _10 means extremely important_, how important are each of the following **Niagara Peninsula Energy** priorities to you as a customer?

Code	Response	
00	Not important at all	
01		
02		
03		
04		
05	Somewhat important	
06		
07		
08		
09		
10	Extremely important	
98	Don't know	

Randomize

C10. Delivering electricity at reasonable distribution rates

C11. Ensuring reliable electrical service

C12. Finding internal efficiencies and ways to find cost savings

C13. Upgrading the electrical system to better respond to and withstand the impact of adverse weather

C14. Proactively replacing aging infrastructure that is beyond its useful life

C15. Providing quality customer service and enhanced communications

C16. Providing tools and services that allow customers to better manage their electricity usage

End Battery

C18. Now thinking of the priorities that we just discussed, please tell me which one is most important to you. [**RANDOMIZE & READ LIST**]

01	Delivering electricity at reasonable distribution rates	
02	Ensuring reliable electrical service	
03	Finding internal efficiencies and ways to find cost savings	
04	Upgrading the electrical system to better respond to and withstand the impact of adverse weather and climate change	
05	Proactively replacing aging infrastructure that is beyond its useful life	
06	Providing quality customer service and enhanced communications	
07	Providing tools and services that allow customers to better manage their electricity usage	
98	Don't know [**DO NOT READ**]	
99	Refused [**DO NOT READ**]	

C19. What is the next most important priority you think **Niagara Peninsula Energy** should focus on?

[**Remove answer from C18. If asked, read list again**]

C20. And what do you consider the third most important priority?

[**Remove answer from C18 and C19. If asked, read list again**]

C21. Can you think of any other important priorities that **Niagara Peninsula Energy** should be focusing on? [**OPEN**]

98	Don't know [**DO NOT READ**]	
99	Refused [**DO NOT READ**]	

D. RELIABILITY OUTCOMES

D22. *Now, let's talk about the reliability of electricity service you receive.* Have you experienced any power outages at **home** **in the past 12 months** which *lasted longer than one minute*? If so, approximately how many of these power outages did you experience? [**DO NOT READ LIST**]

00	No outages	
01	1 outage	
02	2 outages	
03	3 outages	
04	4 outages	
05	5 outages	
06	6 outages	
07	7 outages	
08	8 or more outages	
98	Don't know [**DO NOT READ**]	
99	Refused [**DO NOT READ**]	

D23. And when it comes to reliability, there are a number of areas that **Niagara Peninsula Energy** could focus on. Among the following reliability outcomes, please tell me which one is most important to you. [READ LIST]

01	Reducing the overall number of outages
02	Reducing the overall length of outages
03	Reducing the number of outages during extreme weather events
04	Reducing the length of time to restore power during extreme weather events
05	Improving the quality of power, as judged by momentary interruptions in power that can result in the flickering or dimming of lights
98	Don't know [**DO NOT READ**]
99	Refused [**DO NOT READ**]

D24. What is the next most important reliability outcome you think **Niagara Peninsula Energy** should focus on?

[**Remove answer from D23 if asked to read again**]

D25. And what do you consider the third most important reliability outcome?

[**Remove answer from D23 and D24 if asked to read again**]

E. INVESTMENT TRADE-OFFS

Niagara Peninsula Energy is in the early stages of developing its investment plan for the next five years. While conversations with customers will continue over the next several months, the utility wants to find your preferences when it comes to finding the right balance between costs and other outcomes.

There are four investment categories that we would like to discuss.

System Renewal

E26. The first category focuses on projects that replace and restore aging electrical infrastructure, like overhead poles and underground cables.

Regarding investments in aging infrastructure, which of the following statements best represents your point of view? [**READ LIST; ROTATE 01 & 02**]

01	**Niagara Peninsula Energy** should invest what it takes to replace the system's aging infrastructure to maintain system reliability; even if that increases my monthly electricity bill by a few dollars over the next few years
02	**Niagara Peninsula Energy** should defer its investments in replacing aging infrastructure to lessen the impact of any bill increase; even if this could eventually lead to more or longer power outages
98	Don't know

General Plant

E27. The second category focuses on keeping **Niagara Peninsula Energy's** business running. This includes facilities to house staff and equipment, vehicles and tools to service equipment, and IT systems to manage the system and customer information.

Regarding these types of investments, which of the following statements best represents your point of view? [**READ LIST; ROTATE 01 & 02**]

01	**Niagara Peninsula Energy** should find ways to make do with the facilities, equipment, vehicles and IT and computer systems it already has
02	**Niagara Peninsula Energy** should make the investments necessary to ensure its staff have the equipment and IT and computer systems they need to manage the system efficiently and reliably
98	Don't know

System Service

E28. The third investment category focuses on growth and greater demand for electricity in various parts of **Niagara Peninsula Energy's** service territory.

Increased demand for electricity puts pressure on existing electrical infrastructure. Eventually, further infrastructure investments are required to support increased demand for electricity.

With this in mind, which of the following statements best represents your point of view? [**READ LIST; ROTATE 01 & 02**]

01	To help keep rate increases down, **Niagara Peninsula Energy** should delay investments in system capacity needs until customers start to experience a decline in reliability
02	**Niagara Peninsula Energy** should proactively invest in system capacity infrastructure to ensure customers in high growth areas do not experience a decrease in reliability, even if this adds a small increase to customer bills.
98	Don't know

Grid Modernization

E29. The final category is related to new technology that **Niagara Peninsula Energy** can implement, which may eventually save customers' money down the road. These types of investments could include electricity storage, solar energy or grid automation to more easily re-route power in the case of an outage.

With this in mind, which of the following statements best represents your point of view? [**READ LIST; ROTATE 01 & 02**]

01	**Niagara Peninsula Energy** should proactively invest in modernizing the grid now, knowing it will cost more now, but could eventually save customers' money down the road
02	**Niagara Peninsula Energy** should make investments decisions based on the lowest-cost, proven options like poles and wires, even if that means delaying the benefits of modernizing the grid
98	Don't know

E30. To the best of your knowledge, does your home receive electrical service via overhead wires, underground cables or would you say you *don't know*?

01	Overhead wires	
02	Underground cables	
98	Don't know	
99	Refused [**DO NOT READ**]	

F. DEMOGRAPHICS

Lastly, I'd like to ask you some general questions about the electricity system in Ontario.

For each statement please tell me if you would strongly agree, somewhat agree, somewhat disagree or strongly disagree. If you don't know enough to say or don't have an opinion just let me know.

01	Strongly agree
02	Somewhat agree
03	Somewhat disagree
04	Strongly disagree
98	Don't know/No opinion
99	Refused [**DNR**]

[ROTATE]

F31. The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.

F32. Customers are well served by the electricity system in Ontario.

[END BATTERY]

General Demos

These final few questions are for statistical purposes only.

F33. What is the highest level of education that you have *completed*? *Would you say …* [**READ LIST**]

01	No formal schooling	
02	Some elementary or high school	
03	High school	
04	Apprenticeship or trades certificate or diploma	
05	College, CEGEP, or collège classique	
06	Bachelor's degree	
07	Degree in medicine, dentistry, veterinary medicine, or optometry	
08	Master's degree	
09	Doctorate	

F34. Which of the following categories best describes your current employment status? *Would you say …* [**READ LIST**]

01	Self-employed	
02	Employed full-time	
03	Employed part-time	
04	Seasonal employment	
05	Term employment	
06	Unemployed	
07	Student	
08	Retired	
09	Homemaker	
10	Disability/sick leave	
11	Maternity/paternal leave	
88	Other	[please specify]
99	Prefer not to say / refused [**DNR**]	

F35. Including yourself, how many people live in your household? **[DO NOT READ LIST]**]

01	Single person household	
02	2 people	
03	3 people	
04	4 people	
05	5 people	
06	6 people	
07	7 people	
08	8 people or more	
99	Prefer not to say [**DNR**]	

F36. Finally, which of the following categories best describes the total annual income, **after taxes**, of all the members of your household? *Would you say…* [**READ LIST**]

01	Less than $28,000	
02	$28,000 to less than $39,000	
03	$39,000 to less than $48,000	
04	$48,000 to less than $52,000	
05	$52,000 to less than $70,000	
06	$70,000 to less than $90,000	
07	$90,000 to less than $120,000	
09	$120,000 or more	
99	Prefer not to say	

ASK IF EMAIL==0

F37. Over the next few months, **Niagara Peninsula Energy** will be seeking further customer feedback on their plans via an online survey. Would you like us to send you an email invitation to participate in this survey? Your email will only be used for the purpose of sending you the survey.

01	Yes	
02	No	

EMAIL ASK IF F37=1

F38. And, what email would you like the survey sent to?

[ALWAYS READ BACK TO CONFIRM SPELLING]

THANK and END SURVEY

Thank you very much for taking the time to complete this survey.

Telephone Reference Survey

Small Business Ratepayer Questionnaire

July 2019

Prepared by:

Innovative Research Group, Inc.
www.innovativeresearch.ca

Vancouver
888 Dunsmuir Street, Suite 350
Vancouver BC | V6C 3K4

Toronto
56 The Esplanade, Suite 310
Toronto, Ontario | M5E 1A7

A. SCREENING AND QUALIFICATIONS

Introduction

Hello, my name is ____________ and I'm calling from **Innovative Research Group** on behalf of **Niagara Peninsula Energy**, your local electricity distributor.

Innovative Research Group is a national public opinion research firm. **We need your input on choices that will affect the service you receive from Niagara Peninsula Energy.** Your answers will be combined with others to protect your privacy.

Can I please speak to the person who is in-charge of managing the electricity bill at your organization?

1) Yes, speaking <**contact on the line**>	**[skip to A1]**
2) Yes <**transferred to contact**>	**[skip to A1]**
3) No <**not the right contact person**>	**[GO to "NEW"]**
4) No <**busy**> "When is a good time to callback?"	**[record callback time]**
5) Maybe <**may I ask who is calling?**>	**[skip to GATE]**

NEW. And … can I have their …

First Name __________
Last Name __________
Title/Position _________
Phone Number ________

ASK to be transferred …

- **if transferred → go to A2**
- **if not transferred → Thank & Add to Callback List**

GATE. Hello, my name is ____________ and I'm calling from **Innovative Research** on behalf of **Niagara Peninsula Energy,** your local electricity distributor.

INTERVIEWER NOTE: If gatekeeper asks the purpose of call → I'd like to ask the person in-charge of managing the electricity bill at your organization a few questions concerning a **Niagara Peninsula Energy** customer consultation.

1) Yes <**transferred to contact**>		**[skip to A2]**
2) No <**not available**>	"*When is a good time to callback*?	**[record call-back time and go to "NEW"]**
3) No <**not interested in talking**>		**[Thank & Terminate]**

A1 QUAL PREAMBLE:

Read preamable again, if transferred to new person:

Hello, my name is _______________ and I'm calling from **Innovative Research** on behalf of **Niagara Peninsula Energy**, your local electricity distributor.

Innovative Research is a national public opinion research firm**.** We have been hired by **Niagara Peninsula Energy** to help them better understand the needs and preferences of non-residential customers who are responsible for paying their organization's electricity bill.

A1. Can I have roughly **7 minutes** of your time to ask you some questions? All your responses will be kept strictly confidential.

Yes – I don't mind	1	[CONTINUE]
No – Not primary bill payer (i.e. not best person to speak to)	2	[go to TRANSFER]
No – BAD TIME	3	[ARRANGE CALLBACK]
No – HARD REFUSAL	4	[THANK & TERMINATE]

MONIT [INTERNAL]

This call may be monitored or audio taped for quality control and evaluation purposes.

PRESS TO CONTINUE 1

A2. Can you confirm that your organization receives an electricity or hydro bill from **Niagara Peninsula Energy**?

YES	1	[CONTINUE]
NO	2	[THANK & TERMINATE]
DK (volunteered)	98	[THANK & TERMINATE]

A3. As part of your job, are you in charge of managing or overseeing your organization's electricity or hydro bill?

YES	1		[CONTINUE]
NO	2	"Can I speak to the person who manages your organization's electricity bill?"	[Return to **NEW**]
DK	3	"Can I speak to the person who manages your organization's electricity bill?"	[Return to **NEW**]

TRANSFER

Can I please speak to the person who is in-charge of managing the electricity bill at your organization?

Yes	1	[BACK TO ***INTRO***]
No – NOT AVAILABLE/BAD TIME – (ARRANGE CALLBACK)	2	[ARRANGE CALLBACK]
No – HARD REFUSAL	3	[THANK & TERMINATE]

A4. <blank>

B. INTRODUCTION AND CORE MEASURE

[PREAMBLE]

Today I want to talk about **Niagara Peninsula Energy** and the local electricity system in your community.

There are three topics I would like to discuss:

- First, we will talk about your experience with Niagara Peninsula Energy.
- Second, we will talk about the outcomes that matter most to your organization;
- And finally, we will talk about some trade-offs in planning future investments.

First, let's talk about your experience.

While you might have multiple accounts with Niagara Peninsula Energy, for this survey, we want you to think about your overall experience as a **small business** customer.

The following questions are about **Niagara Peninsula Energy's** distribution system. This is the system that takes the electricity from high-voltage transmission towers and brings it to your organization through a network of wires, poles and other equipment that is owned and operated by **Niagara Peninsula Energy**.

B5. How familiar are you with **Niagara Peninsula Energy**, which operates the electricity distribution system in your community?

Would you say you are *very familiar*, *somewhat familiar*, *not familiar* or would you say you *don't know*?

01	Very familiar	
02	Somewhat familiar	
03	Not familiar	
98	Don't know	
99	Refused [**DO NOT READ**]	

B6. Thinking specifically about the services provided by **Niagara Peninsula Energy**, overall, how satisfied or dissatisfied are you with the services that your organization receives?

Would you say you are *very satisfied, somewhat satisfied, neither satisfied nor dissatisfied, somewhat dissatisfied, very dissatisfied or would you say you don't know*?

01	Very satisfied	
02	Somewhat satisfied	
03	Neither satisfied or dissatisfied	
04	Somewhat dissatisfied	
05	Very dissatisfied	
98	Don't know	
99	Refused [**DO NOT READ**]	

B7. And, is there anything in particular you would like **Niagara Peninsula Energy** to do to improve its services to you? [**OPEN**]

98	Don't know	
99	Refused [**DO NOT READ**]	

B8. While **Niagara Peninsula Energy** is responsible for collecting payment for the entire electricity bill, it keeps about **23%** of the average small business' bill. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.

Before this survey, how familiar were you with the amount of your electricity bill that went to **Niagara Peninsula Energy**? Would you say you were *very familiar, somewhat familiar, not familiar or would you say you don't know?*

01	Very familiar
02	Somewhat familiar
03	Not familiar
98	Don't know

Bill Type

B9. And does your organization receive a monthly bill from Niagara Peninsula Energy as a **paper bill** or an **electronic bill**?

01	Paper Bill	
02	E-Bill	
98	Don't know [**DO NOT READ**]	

C. CUSTOMER PRIORITIES

Now, let's talk about our second topic – outcomes.

Every day, **Niagara Peninsula Energy** interacts with hundreds of its customer through multiple channels and touchpoints, including surveys, the call centre, and social media.

In a recent series of customer focus groups, a number of company goals were identified as priorities for **Niagara Peninsula Energy**.

Using a scale from 0 to 10, where _0 means not important at all_ and _10 means extremely important_, how important are each of the following **Niagara Peninsula Energy** priorities to you as a small business customer?

Code	Response	
00	Not important at all	
01		
02		
03		
04		
05	Somewhat important	
06		
07		
08		
09		
10	Extremely important	
98	Don't know	

Randomize

C10. Delivering electricity at reasonable distribution rates

C11. Ensuring reliable electrical service

C12. Finding internal efficiencies and ways to find cost savings

C13. Upgrading the electrical system to better respond to and withstand the impact of adverse weather

C14. Proactively replacing aging infrastructure that is beyond its useful life

C15. Providing quality customer service and enhanced communications

C16. Providing tools and services that allow customers to better manage their electricity usage

End Battery

C18. Now thinking of the priorities that we just discussed, please tell me which one is most important to your organization. [READ LIST]

01	Delivering electricity at reasonable distribution rates	
02	Ensuring reliable electrical service	
03	Finding internal efficiencies and ways to find cost savings	
04	Upgrading the electrical system to better respond to and withstand the impact of adverse weather and climate change	
05	Proactively replacing aging infrastructure that is beyond its useful life	
06	Providing quality customer service and enhanced communications	
07	Providing tools and services that allow customers to better manage their electricity usage	
08	Support the local economy and community groups through new incentives programs	
98	Don't know [**DO NOT READ**]	
99	Refused [**DO NOT READ**]	

C19. What is the next most important priority you think **Niagara Peninsula Energy** should focus on?
[**Remove answer from C18.If asked, read list again**]

C20. And what do you consider the third most important priority?
[**Remove answer from C18 and C19. Ifasked, read list again**]

C21. Can you think of any other important priorities that **Niagara Peninsula Energy** should be focusing on? [**OPEN**]

98	Don't know [**DO NOT READ**]	
99	Refused [**DO NOT READ**]	

D. RELIABILITY OUTCOMES

D22. *Now, let's talk about the reliability of electricity service you receive.* Has your organization experienced any power outages **in the past 12 months** which *lasted longer than one minute*? If so, approximately how many of these power outages did you experience? [**DO NOT READ LIST**]

00	No outages	
01	1 outage	
02	2 outages	
03	3 outages	
04	4 outages	
05	5 outages	
06	6 outages	
07	7 outages	
08	8 or more outages	
98	Don't know [**DO NOT READ**]	
99	Refused [**DO NOT READ**]	

D23. And when it comes to reliability, there are a number of areas that **Niagara Peninsula Energy** could focus on. Among the following reliability outcomes, please tell me which one is most important to your organization. [READ LIST]

01	Reducing the overall number of outages
02	Reducing the overall length of outages
03	Reducing the number of outages during extreme weather events
04	Reducing the length of time to restore power during extreme weather events
05	Improving the quality of power, as judged by momentary interruptions in power that can result in the flickering or dimming of lights
98	Don't know [**DO NOT READ**]
99	Refused [**DO NOT READ**]

D24. What is the next most important reliability outcome you think **Niagara Peninsula Energy** should focus on?

[**Remove answer from D23 if asked to read again**]

D25. And what do you consider the third most important reliability outcome?

[**Remove answer from D23 and D24 if asked to read again**]

E. INVESTMENT TRADE-OFFS

Niagara Peninsula Energy is in the early stages of developing its investment plan for the next five years. While conversations with customers will continue over the next several months, the utility wants to find your preferences when it comes to finding the right balance between costs and other outcomes.

There are four investment categories that we would like to discuss.

System Renewal

E26. The first category focuses on projects that replace and restore aging electrical infrastructure, like overhead poles and underground cables.

Regarding investments in aging infrastructure, which of the following statements best represents your point of view? [**READ LIST; ROTATE 01 & 02**]

01	**Niagara Peninsula Energy** should invest what it takes to replace the system's aging infrastructure to maintain system reliability; even if that increases your organization's monthly electricity bill by a few dollars over the next few years
02	**Niagara Peninsula Energy** should defer its investments in replacing aging infrastructure to lessen the impact of any bill increase; even if this could eventually lead to more or longer power outages
98	Don't know

General Plant

E27. The second category focuses on keeping **Niagara Peninsula Energy's** business running. This includes facilities to house staff and equipment, vehicles and tools to service equipment, and IT systems to manage the system and customer information.

Regarding these types of investments, which of the following statements best represents your point of view? [**READ LIST; ROTATE 01 & 02**]

01	**Niagara Peninsula Energy** should find ways to make do with the facilities, equipment, vehicles and IT and computer systems it already has
02	**Niagara Peninsula Energy** should make the investments necessary to ensure its staff have the equipment and IT and computer systems they need to manage the system efficiently and reliably
98	Don't know

System Service

E28. The third investment category focuses on growth and greater demand for electricity in various parts of **Niagara Peninsula Energy's** service territory.

Increased demand for electricity puts pressure on existing electrical infrastructure. Eventually, further infrastructure investments are required to support increased demand for electricity.

With this in mind, which of the following statements best represents your point of view? [**READ LIST; ROTATE 01 & 02**]

01	To help keep rate increases down, **Niagara Peninsula Energy** should delay investments in system capacity needs until customers start to experience a decline in reliability
02	**Niagara Peninsula Energy** should proactively invest in system capacity infrastructure to ensure customers in high growth areas do not experience a decrease in reliability, even if this adds a small increase to customer bills.
98	Don't know

Grid Modernization

E29. The final category is related to new technology that **Niagara Peninsula Energy** can implement, which may eventually save customers' money down the road. These types of investments could include electricity storage, solar energy or grid automation to more easily re-route power in the case of an outage.

With this in mind, which of the following statements best represents your point of view? [**READ LIST; ROTATE 01 & 02**]

01	**Niagara Peninsula Energy** should proactively invest in modernizing the grid now, knowing it will cost more now, but could eventually save customers' money down the road
02	**Niagara Peninsula Energy** should make investments decisions based on the lowest-cost, proven options like poles and wires, even if that means delaying the benefits of modernizing the grid
98	Don't know

E30. To the best of your knowledge, does your organization receive electrical service via overhead wires, underground cables or would you say you *don't know*?

01	Overhead wires	
02	Underground cables	
98	Don't know	
99	Refused [**DO NOT READ**]	

F. FIRMOGRAPHICS

Lastly, I'd like to ask you some general questions about the electricity system in Ontario.

For each statement please tell me if you would strongly agree, somewhat agree, somewhat disagree or strongly disagree. If you don't know enough to say or don't have an opinion just let me know.

01	Strongly agree
02	Somewhat agree
03	Somewhat disagree
04	Strongly disagree
98	Don't know/No opinion
99	Refused [**DNR**]

[ROTATE]

F31. The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.

F32. Customers are well served by the electricity system in Ontario.

[END BATTERY]

General Demos

These final few questions are for statistical purposes only.

F33. Which of the following best describes the sector in which your business operates? Would you say… [**READ LIST**]

01	Commercial	
02	Manufacturing/Industrial	
03	Data Centre	
04	Hospitality	
05	Restaurant/Tavern	
06	Retail	
07	Warehouse	
88	Other [Please specify:________________]	

F34. Which of the following best describes the **hours of operation** of your business? *Would you say…* [**READ LIST**]

01	You are open 24/7	
02	You operate several shifts each day, but are not open 24/7	
03	You operate during regular business hours only	
04	You operate outside of regular business hours, but do not have shifts	
88	Other [**DNR**]	[please specify]
99	Prefer not to say / refused [**DNR**]	

F35. And, which of the following best describes when your business operates throughout the week? *Would you say…* [**READ LIST**]

01	You operate on weekdays only	
02	You operate on weekdays and weekends	
88	Other [**DNR**]	[please specify]
99	Prefer not to say / refused [**DNR**]	

ASK IF EMAIL==0

F36. Over the next few months, **Niagara Peninsula Energy** will be seeking further customer feedback on their plans via an online survey. Would you like us to send you an email invitation to participate in this survey? Your email will only be used for the purpose of sending you the survey.

01	Yes	
02	No	

EMAIL ASK IF F36=1

F37. And, what email would you like the survey sent to?

[ALWAYS READ BACK TO CONFIRM SPELLING]

THANK and END SURVEY

Thank you very much for taking the time to complete this survey.

INNOVATIVE RESEARCH GROUP

2021-2025 Rate Application

Representative Report

niagara peninsula energy inc.
Your Local Utility

January 2020

STRICTLY PRIVILEGED AND CONFIDENTIAL

Table of Contents

Introduction

Representative Online Workbook

Niagara Peninsula Energy's 2021-2025 Rate Application Customer Engagement

Innovative Research Group Inc. (INNOVATIVE) was engaged by Niagara Peninsula Energy (NPEI) to assist in meeting NPEI's customer engagement commitments under the Renewed Regulatory Framework for Electricity Distributors. The information contained within this report are the result of a series of customer engagements workbooks.

Setting the Context (Phase I)

NPEI's 2021-2025 Rate Application Customer Engagement was designed in two phases. The first phase, which was finalized in August 2019 focused on conducted parallel telephone and online surveys. Running parallel telephone and online surveys serve two primary purposes:

1. **To gather feedback and insights on the *priorities*, *preferences* and *needs* important to low-volume customers**.
   Feedback from these surveys helped NPEI planners and engineers inform the design of the utility's DSP and Business Plan, which was shared in draft, with customers in Phase II of this engagement.
2. **To establish baselines and develop weights that allowed NPEI to move to an online methodology in Phase II of this engagement.**
   Determining the baseline and understanding the difference between customers with known email addresses (email sample), and the broader customer base (telephone sample), was a critical step to migrate to a representative online survey methodology in the second phase of engagement.

Phase II Customer Engagement

NPEI is in the process of developing its 2021-2025 Rate Application. This report covers the second phase of engagement which focused on customer preferences on program timing and balancing outcomes. In order to obtain this feedback from customers, an online "workbook" was deployed to all customers with an email address, as well as promoted through a generic link on NPEI's website and social media platforms.

Interpreting the Results

For residential and small business (GS<50kW), responses were weighted by region and usage to ensure the responses were representative of the broader customer base. Due to small sample size, commercial (GS>50kW) results were not weighted and should be interpreted as directional only. Based on the comparative results of the first phase of the customer engagement, INNOVATIVE is confident that the residential and small business online workbook results contained within this report are representative of NPEI's actual customer base.

Sample Validation

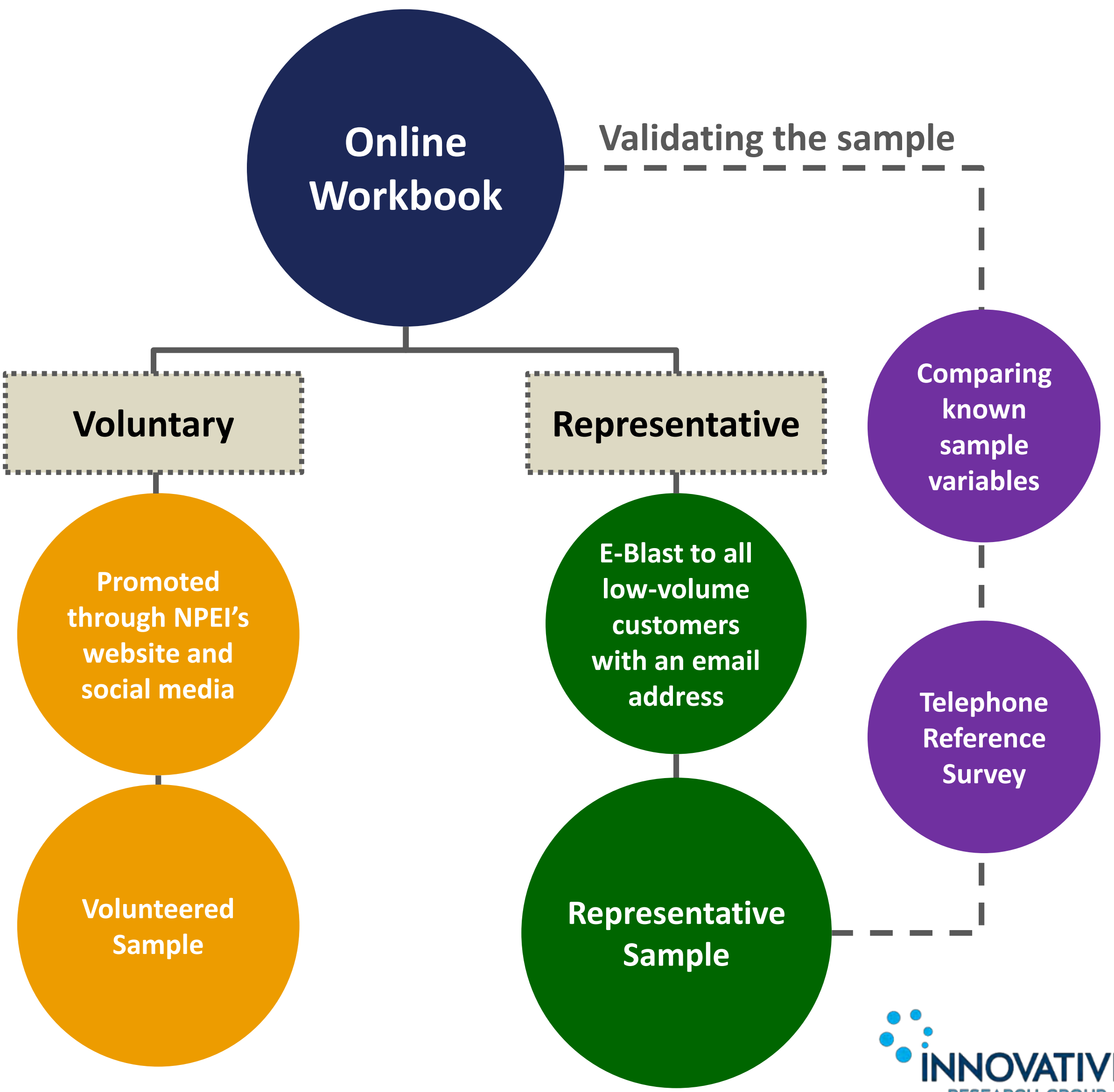
Overall Approach

NPEI's low volume (residential and small business) customer engagement workbook featured two streams – *representative* and *voluntary*.

The voluntary stream created an open process that allowed anyone who wants to be heard an opportunity to express themselves, including those who have not provided the utility with an email address. *Those results are provided in a separate report.*

The representative stream ensures a representative sample of customers are engaged, allowing for the generalizability of findings. *This is a report of those responses.*

The GS>50kW workbook was only accessible through a unique URL sent to customers. There was no voluntary stream for this version of the workbook.



Sample Validation

Email Sample vs. Broader Sample

Comparing the overall population to the sample of that population with email addresses across known variables, we can see that the email sample is largely representative of the overall population of customers.

Overall Coverage

Coverage is lower among residential customers among whom only 27% of the full population have email addresses on file, while among GS<50 customers 44% have email addresses on file. A total of 4,710 residential and 88 GS<50 customers did not have either an email address or a telephone number on file.

Rate Class	Full Population	Telephone Coverage	Email Coverage	
Residential	48,421 records	42,958 records	13,154 records	**27% of the full population**
GS<50	4,496 records	4,382 records	1,928 records	**44% of the full population**

Average Consumption

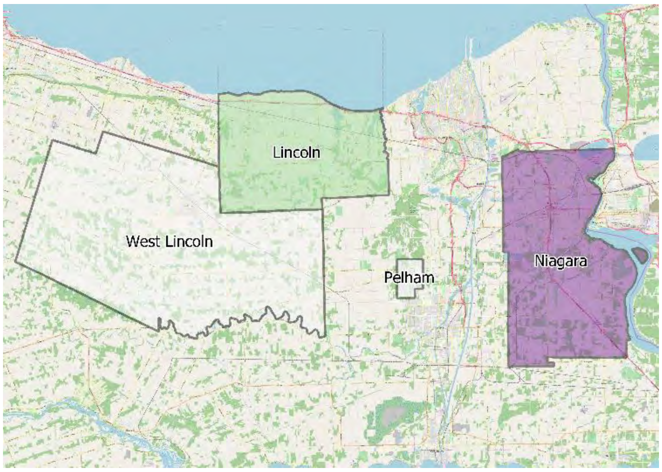
Average consumption is higher for customers in the email sample than it is among the full population for all rate classes. The largest differences exist among both groups of business customers. The final data is weighted on consumption to account for this difference.

Rate Class	Full Population	Telephone Sample	Email Sample	Diff. between email and full
Residential	700 kWh	726 kWh	727 kWh	**+4%**
GS<50	2,154 kWh	2,158 kWh	2,413 kWh	**+12%**

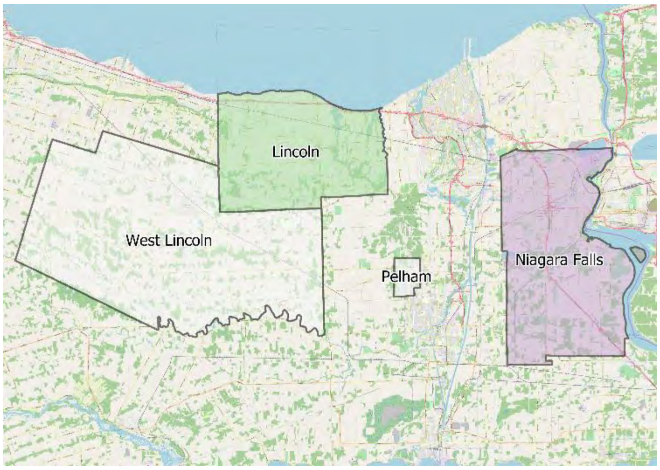
Sample Validation

Regional Analysis

Comparing the overall population to the sample of that population with email addresses across known variables, we can see that no group is substantially underrepresented in the email sample.



GS<50



Residential

Difference between the email sample and the full population
More than -5%
-5% to -2%
-2% to +2%
+2% to +5%
More than +5%

Customers are grouped into regions based on the service area listed on their account: Niagara Falls, Lincoln, West Lincoln, and Pelham.

Among residential customers, Niagara Falls as a region makes up 70% of the full population, but only 66% of the email sample. Lincoln makes up only 18% of the full population, but 21% of the email sample.

Among small business customers, the difference between the full population and the email sample is slightly larger for Niagara Falls and Lincoln. Niagara Falls is 65% of the full population and only 60% of the email sample, while Lincoln is 20% of the full population and 23% of the email sample.

The sample is stratified by region to ensure final email results reflect the real regional composition of the population

Phase I Compared to Phase II

Demographics

Comparing Phase I vs. Phase II: In Phase I, one of the core objectives was to establish baseline and understanding the difference between customers with known email addresses (email sample) and the broader customer base to migrate any potential differences in the second phase of the engagement. Comparing the results from Phase I versus Phase II showed that:

1. Overall, the Phase I and II samples look similar on key measures, particularly when it comes to general attitudes towards the electricity sector. The percentage of customers who feel that their electricity bill has a significant impact on their finances is very consistent between sample groups, giving us confidence that the samples hold very similar views towards the sector.

2. With regards to specific demographics, there appears to be a mode effect, with the telephone sample being older than the online sample.

3. There are only minor differences between the samples with regards to household income. Nothing significant that requires any weighting correction.

4. With regards to customer outage experience, again, there are slight differences, with the Phase I online sample experiencing more outages. This can be attributed to either random distribution or a system performance impact.

Gender	**Phase 1** Online	**Phase 1** Telephone	**Phase 2** Workbook
Male	51%	49%	54%
Female	49%	51%	43%
Self-identified	-	-	1%

Age	**Phase 1** Online	**Phase 1** Telephone	**Phase 2** Workbook
18-34	9%	7%	11%
35-44	13%	11%	13%
45-54	16%	16%	17%
55-64	27%	22%	24%
65 or older	35%	44%	33%

Note: sums added before rounding.

Phase I Compared to Phase II

Household Size and Income

Niagara Peninsula Energy Inc.
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Household Size	Phase 1 Online	Phase 1 Telephone	Phase 2 Workbook
Single person household	14%	26%	14%
2 people	50%	39%	47%
3 people	14%	14%	14%
4 people	13%	10%	14%
5 of more people	6%	9%	8%
Prefer not to say	3%	3%	3%

Household Income	Phase 1 Online	Phase 1 Telephone	Phase 2 Workbook
Less than $28,000	5%	10%	10%
$28,000 to less than $39,000	6%	10%	11%
$39,000 to less than $48,000	8%	6%	9%
$48,000 to less than $52,000	6%	7%	6%
$52,000 or more	47%	39%	42%
Prefer not to say	27%	28%	23%

Phase I Compared to Phase II

Attitudes Towards Electricity

Residential

The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.	**Phase 1** Online	**Phase 1** Telephone	**Phase 2** Workbook
Strongly agree	20%	25%	17%
Somewhat agree	36%	24%	32%
Somewhat disagree	22%	23%	23%
Strongly disagree	19%	22%	24%
Don't know/No opinion	3%	5%	4%
Agree (Strongly + Somewhat)	**55%**	**50%**	**49%**
Disagree (Strongly + Somewhat)	**42%**	**45%**	**47%**

Customers are well served by the electricity system in Ontario.	**Phase 1** Online	**Phase 1** Telephone	**Phase 2** Workbook
Strongly agree	26%	36%	32%
Somewhat agree	54%	43%	47%
Somewhat disagree	10%	6%	10%
Strongly disagree	5%	4%	6%
Don't know/No opinion	5%	10%	5%
Agree (Strongly + Somewhat)	**80%**	**79%**	**79%**
Disagree (Strongly + Somewhat)	**15%**	**10%**	**16%**

Phase I Compared to Phase II

Outage Experience

Residential

Number of Outages in Past Year	Phase 1 Online	Phase 1 Telephone	Phase 2 Workbook
No outages	20%	35%	24%
1 outage	21%	17%	26%
2 outages	18%	16%	20%
3 or more outages	32%	25%	21%
Don't know	9%	6%	9%

Note: sums added before rounding.

Phase I Compared to Phase II

Outage Experience

Comparing Phase I vs. Phase II: In Phase I, one of the core objectives was to establish baseline and understanding the difference between customers with known email addresses (email sample) and the broader customer base to migrate any potential differences in the second phase of the engagement. Comparing the results from Phase I versus Phase II showed that:

1. Overall, the Phase I and II samples look similar on key measures, particularly when it comes to general attitudes towards the electricity sector. Like with the residential sample, the percentage of customers who feel that their electricity bill has a significant impact on their organization's bottom line is very consistent between sample groups, giving us confidence that the samples hold very similar views towards the sector.

2. The Phase II representative workbook sample is more vulnerable than the Phase I sample, with more customers saying that the cost of their electricity bill has a major impact on the bottom line of their organization and results in some important spending priorities and investments being put off.

3. There are some differences between the number of outages that customers say that they have experienced in the past 12 months. On average, the Phase I online sample is more likely to have experienced an outage. These differences are not seen to be significant enough to warrant any weighting correction.

Number of Outages in Past Year	Phase 1 Online	Phase 1 Telephone	Phase 2 Workbook
No outages	13%	37%	22%
1 outage	15%	11%	11%
2 outages	11%	16%	33%
3 or more outages	40%	18%	26%
Don't know	21%	19%	8%

Note: sums added before rounding.

Phase I Compared to Phase II

Attitudes Towards Electricity

The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.	**Phase 1** Online	**Phase 1** Telephone	**Phase 2** Workbook
Strongly agree	16%	40%	29%
Somewhat agree	41%	29%	41%
Somewhat disagree	26%	10%	15%
Strongly disagree	8%	9%	13%
Don’t know/No opinion	9%	12%	2%
Agree (Strongly + Somewhat)	**57%**	**69%**	**70%**
Disagree (Strongly + Somewhat)	**34%**	**19%**	**29%**

Customers are well served by the electricity system in Ontario.	**Phase 1** Online	**Phase 1** Telephone	**Phase 2** Workbook
Strongly agree	16%	34%	26%
Somewhat agree	57%	42%	52%
Somewhat disagree	16%	6%	10%
Strongly disagree	4%	7%	9%
Don’t know/No opinion	7%	11%	2%
Agree (Strongly + Somewhat)	**73%**	**76%**	**78%**
Disagree (Strongly + Somewhat)	**20%**	**13%**	**20%**

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RESEARCH GROUP

Residential Customers

Online Workbook Results

Representative Workbook

Survey Design & Methodology

INNOVATIVE was engaged by NPEI to gather input on preferences on program timing and balancing outcomes. **Pages 15 to 68** show the actual pages of the workbook that was sent and completed by customers. The only additions are the actual results.

Field Dates & Workbook Delivery

The **Residential Online Workbook** was sent to all Niagara Peninsula Energy residential customers who have provided the utility with an email address. Customers had an opportunity to complete the workbook between **November 21st and December 17th, 2019**.

Each customer received a unique URL that could be linked back to their annual consumption, region and rate class.

In total, the residential workbook was sent to **11,962** customers via e-blast from INNOVATIVE.

Residential Online Workbook Completes

A total of **1,264** (unweighted) Niagara Peninsula Energy residential customers completed the online workbook via a unique URL.

Sample Weighting

The residential online workbook sample has been weighted proportionately by region and consumption quartiles in order to be representative of the broader Niagara Peninsula Energy service territory.

The table below summarizes the unweighted and weighted (in brackets) sample breakdown by region and quartile.

Region	Consumption Quartiles				Total	Distribution
	Low	Medium-Low	Medium-High	High		
Niagara Falls	215 (210)	224 (210)	192 (210)	134 (210)	765 (839)	61% (66%)
Pelham	15 (10)	14 (10)	12 (10)	9 (10)	50 (40)	4% (3%)
Lincoln	60 (61)	67 (61)	65 (61)	86 (61)	278 (243)	22% (19%)
West Lincoln	19 (35)	45 (35)	40 (35)	67 (35)	171 (142)	14% (11%)
Total	309 (316)	350 (316)	309 (316)	296 (316)	1,264 (1,264)	**100%**

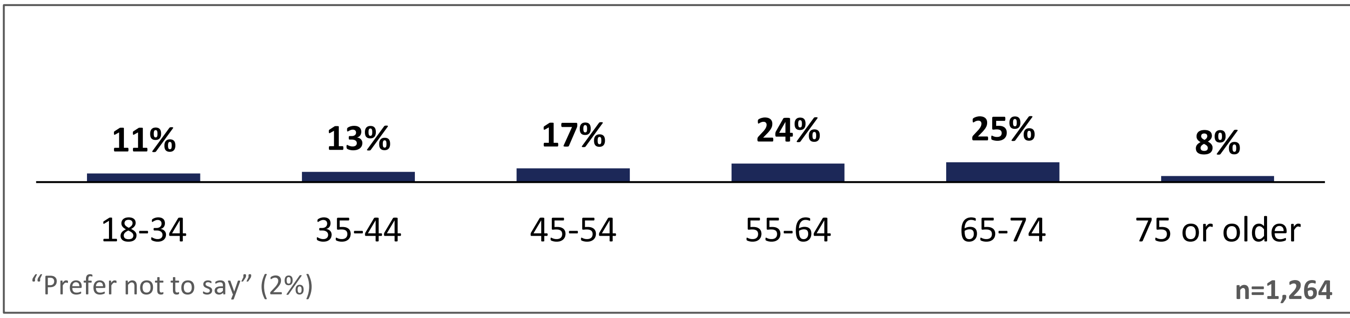
Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Representative Workbook

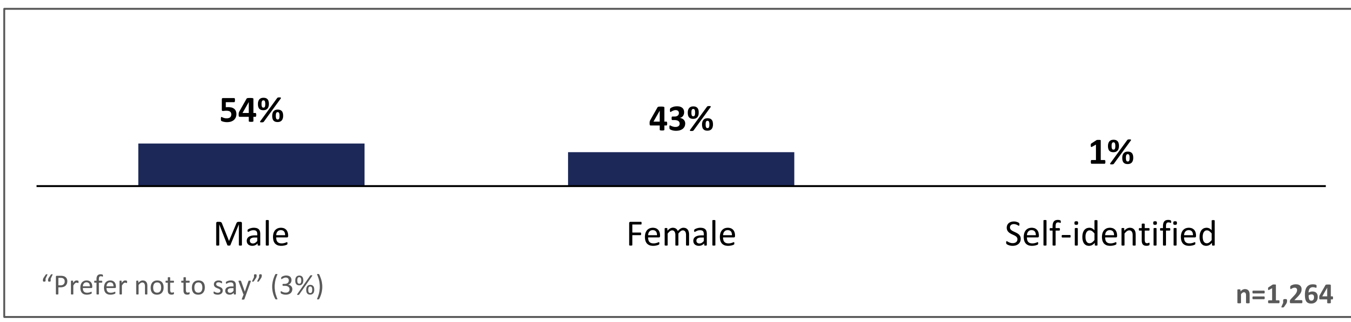
Demographic Breakdown

Residential

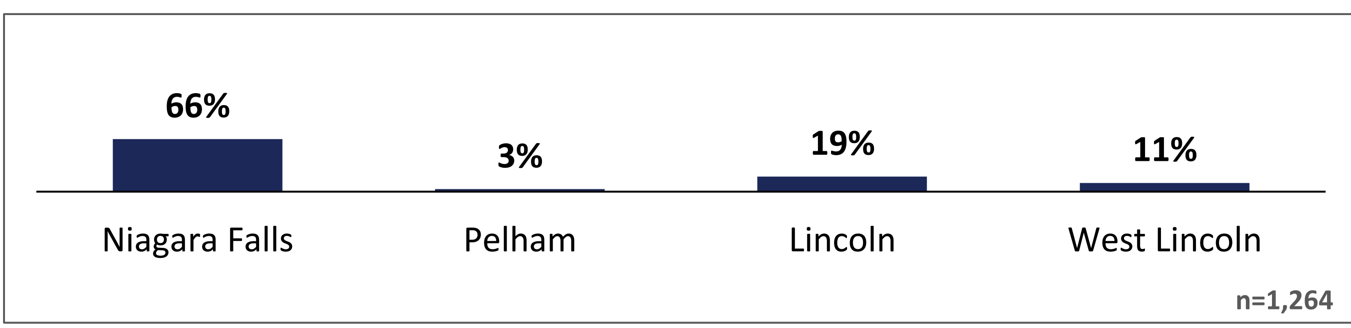
Q Age



Q Gender



Q Region

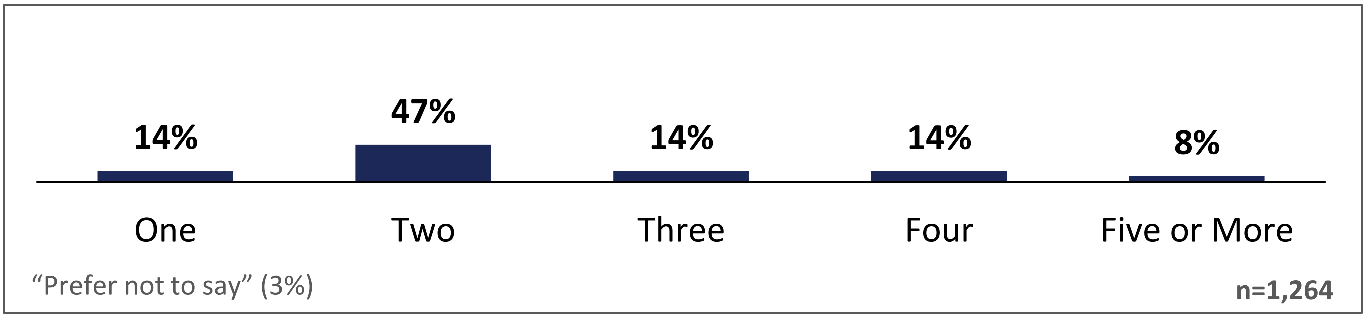


INNOVATIVE RESEARCH GROUP

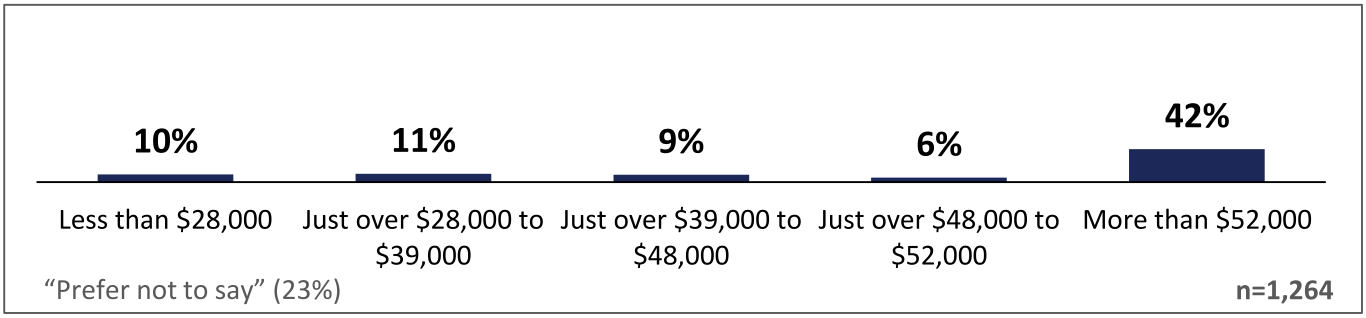
Representative Workbook

Demographic Breakdown

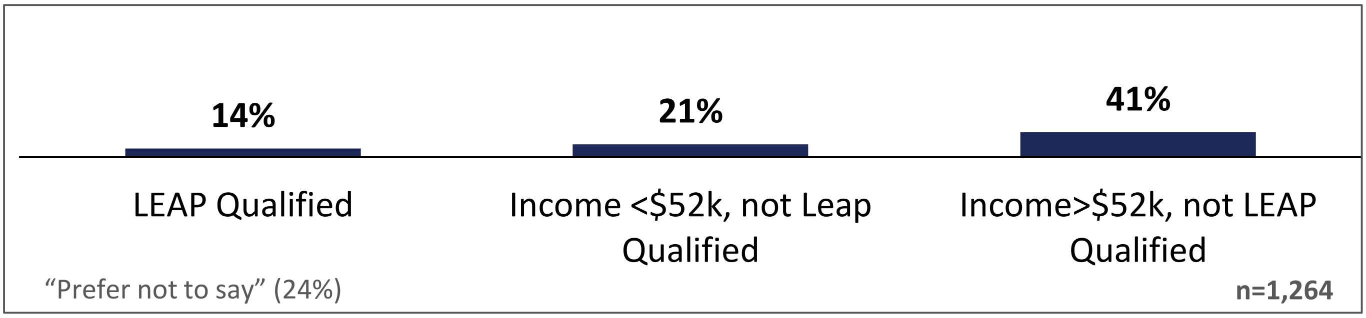
Q Household Size



Q After Tax Household Income



Q **LEAP Qualification** (calculated based on household size and income)



INNOVATIVE RESEARCH GROUP

Representative Workbook

Environmental Controls

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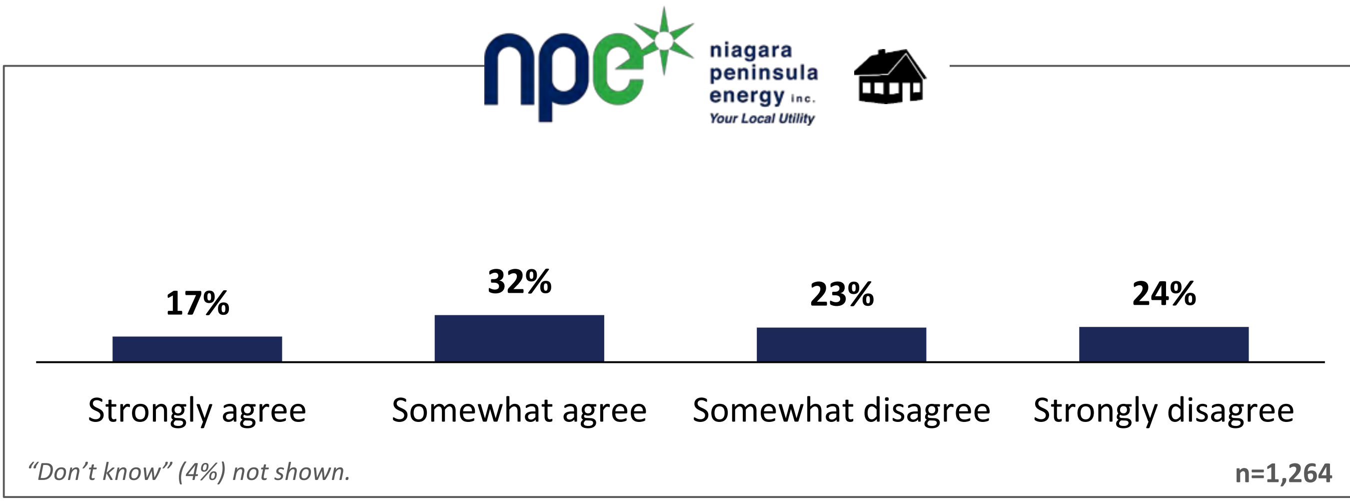
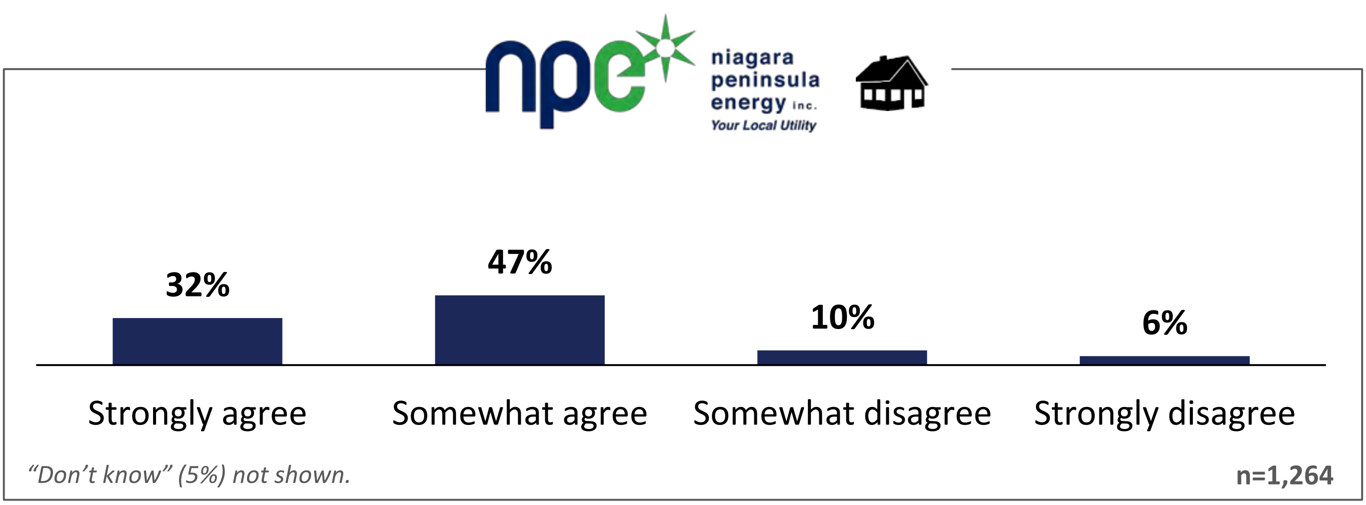
Thinking generally about the electricity system in Ontario, including generation, transmission and local distribution, do you agree or disagree with the following statements?

Q The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.



Q Customers are well served by the electricity system in Ontario.



Representative Workbook

Background Information

Niagara Peninsula Energy Inc.
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About this Consultation

Welcome to Niagara Peninsula Energy's Customer Engagement!

Niagara Peninsula Energy (NPEI) needs your input on choices that will impact the services you receive and the rates that you pay.

- **NPEI** is developing its investment plan for 2021 to 2025. This plan will determine the investments NPEI will make in equipment and infrastructure; the services it provides; and the rates you pay.
- As **NPEI** plans for the future, they want to ensure their business decisions are aligned with customers priorities, preferences, and needs.
- Throughout this survey, information will be provided in an effort to give you more background on which to base your responses.
- While responding to the following questions, remember that there are no wrong answers, and that your individual responses will remain anonymous.
- This customer engagement will take approximately 25-35 minutes to complete, depending on the level of feedback you wish to provide. Your progress will be saved as you move through the workbook, meaning you can leave and return to the customer engagement at any time.

All individual responses will be kept confidential. Innovative Research Group (INNOVATIVE), an independent research company, has been hired NPEI to gather your feedback.

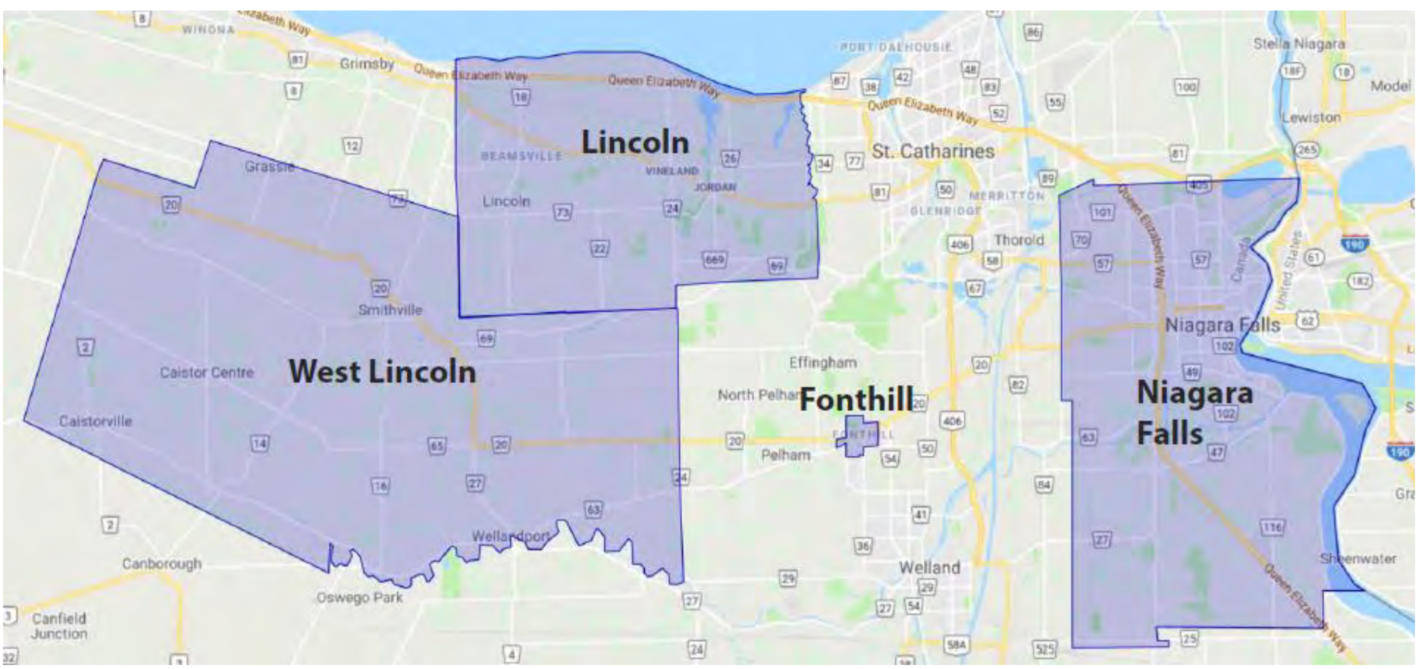
Those who complete the questions that follow will be invited to enter a draw to win one (1) $500 cash prize.

Electricity 101

Who is Niagara Peninsula Energy?

NPEI provides local electricity distribution and related services to residential and business customers in the City of Niagara Falls, Town of Lincoln, Town of Pelham, and Township of West Lincoln.

- NPEI serves an area of approximately 827 square kilometers and 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 local distribution company (LDC) and regulated entity, NPEI applies for, and receives approval from the regulator to charge for its services.



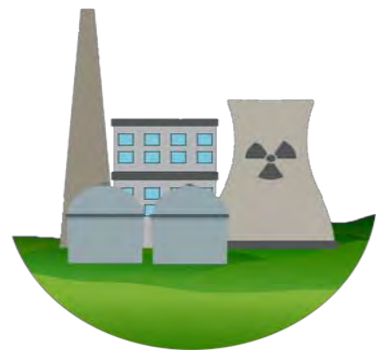
Electricity 101

Niagara Peninsula Energy's Role in Ontario's Electricity System

Ontario's electricity system is owned and operated by public, private, and municipal corporations across the province. It is made up of three key components: **generation**, **transmission** and **distribution**.

Generation

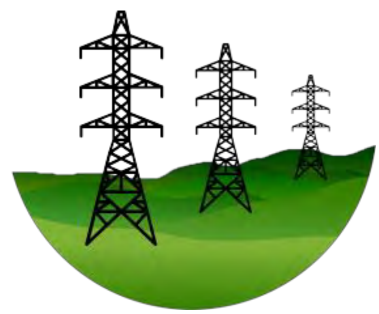
Where electricity comes from



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.

Transmission

How electricity travels across Ontario



Once generated, electricity must be transported to electrical substations 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 kilometres of 'electricity highway', most of which is owned and operated by Hydro One.

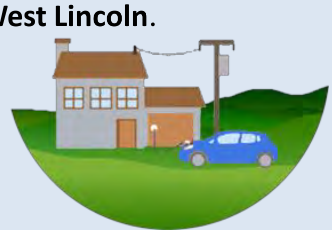
Local Distribution

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. This local distribution system includes transformer stations that decrease the voltage of the electricity so it can be used safely in your home or business.

There are approximately 1,451 km of overhead power lines and 573 km of underground cable. Through this distribution network, NPEI delivers electricity to approximately 55,600 residential and business customers.

Niagara Peninsula Energy Inc. is jointly owned by the **City of Niagara Falls**, the **Town of Lincoln**, the **Town of Pelham** and the **Township of West Lincoln**.



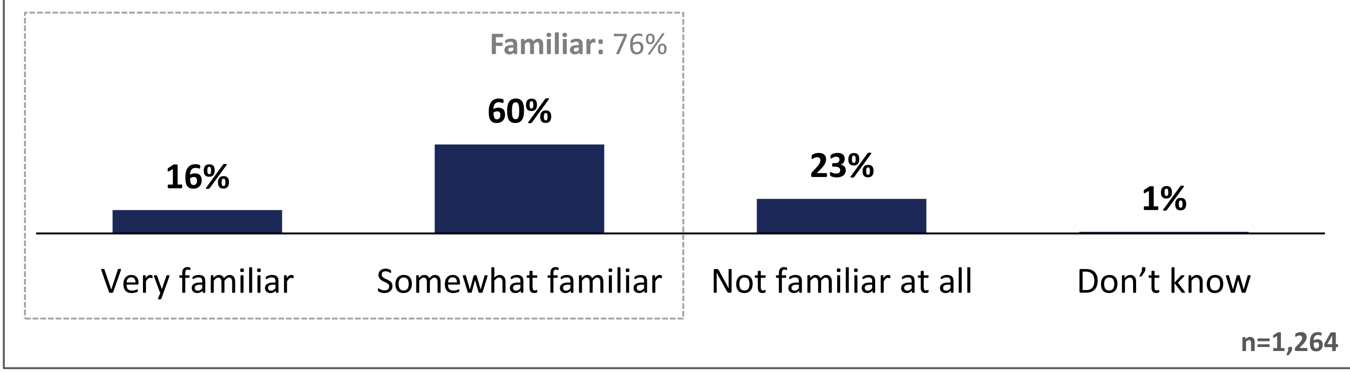
npe niagara peninsula energy Inc. Your Local Utility

Representative Workbook

Familiarity with Ontario's electricity system

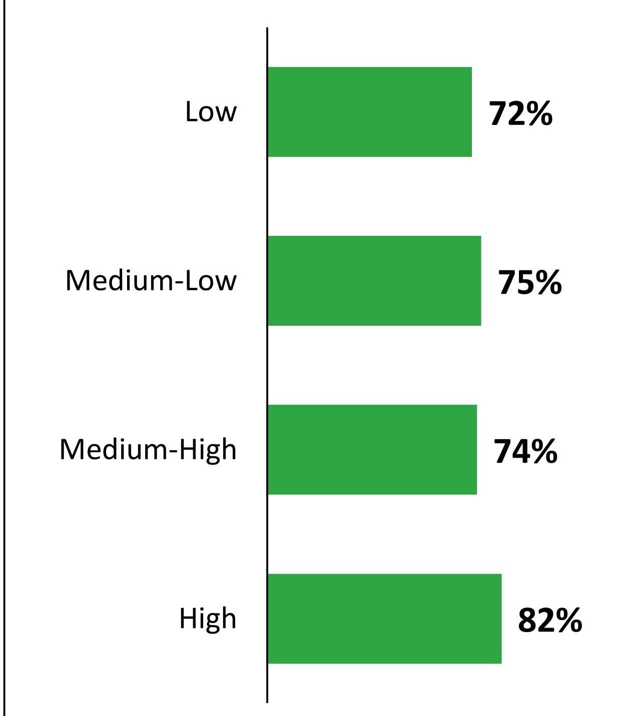
Q Before this survey, how familiar were you with Niagara Peninsula Energy, which operates the electricity distribution system in your community?

niagara peninsula energy inc.
Your Local Utility



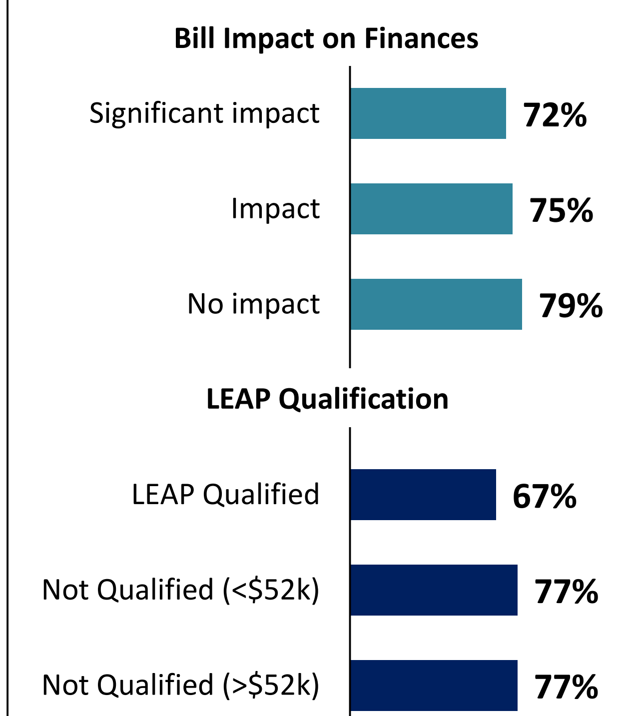
Consumption Segmentation

Respondents who say "Familiar"



Vulnerable Customer Segmentation

Respondents who say "Familiar"



Electricity 101

How much of my electricity bill goes to Niagara Peninsula Energy?

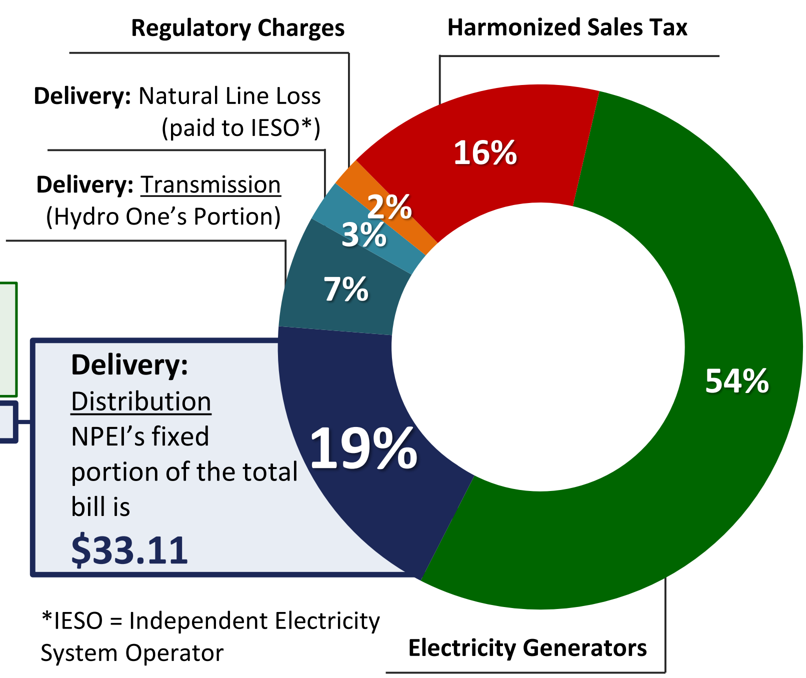
- Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board (OEB), the provincial energy regulator.
- While NPEI is responsible for collecting payment for the entire electricity bill, it retains only the distribution portion of the delivery charge.
- Distribution makes up about **19%** of the typical residential customer's bill.
- For residential customers, NPEI's portion of the delivery line on the bill is fixed and does not change based on the amount of electricity you use.
- The rest of your bill is passed onto provincial transmission companies, power generation companies, the government and regulatory agencies.

NPEI Sample Monthly Bill*
(Based on monthly usage of 700 kWh)

Account Number:
000 000 000 000 0000

Meter Number:
00000000

Your Electricity Charges	
Electricity	
Off-Peak @ 10.1 ¢/kWh	45.25
Mid-Peak @ 14.4 ¢/kWh	18.14
On-Peak @ 20.8 ¢/kWh	26.21
Delivery	46.85
Regulatory Charges	3.11
Total Electricity Charges	**$139.56**
HST	18.14
Ontario Electricity Rebate*	(-$44.38)
Total Amount	**$113.32**



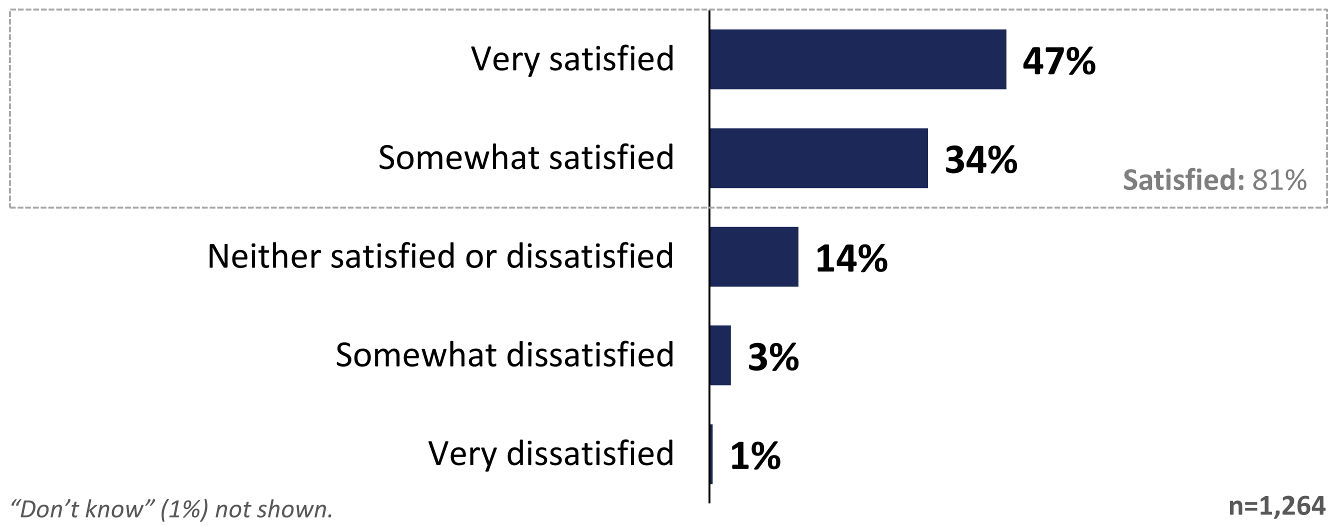
*IESO = Independent Electricity System Operator

* As of November 1, 2019. Chart is based on total bill amount after applying the Ontario Electricity Rebate.

Representative Workbook

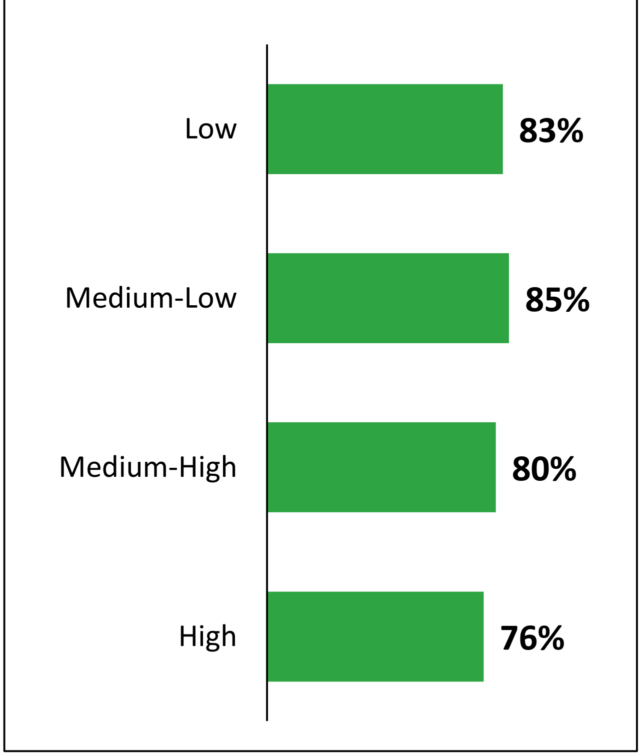
Overall Satisfaction with Niagara Peninsula Energy

Q Thinking specifically about the services provided to you and your community by Niagara Peninsula Energy, overall, how satisfied or dissatisfied are you with the services that you receive?



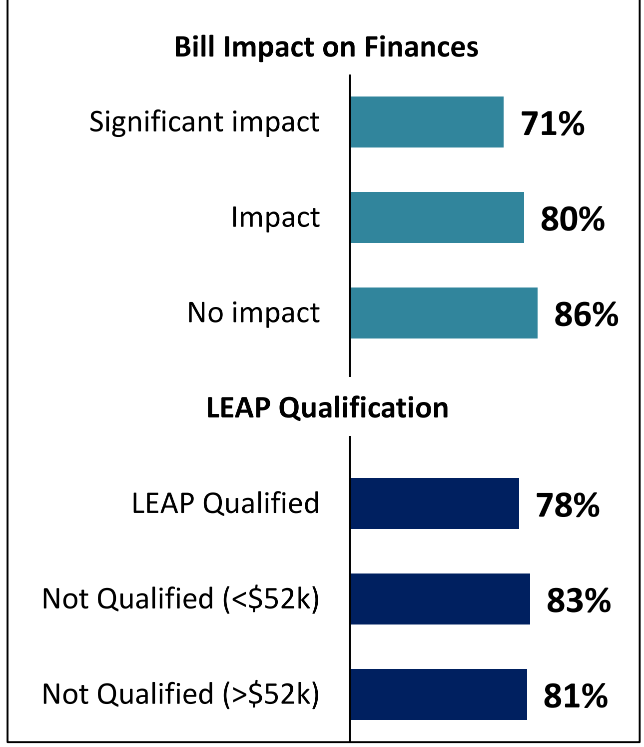
Consumption Segmentation

Respondents who say "Satisfied"



Vulnerable Customer Segmentation

Respondents who say "Satisfied"



Representative Workbook

Familiarity with Percentage if Bill Remitted to NPEI

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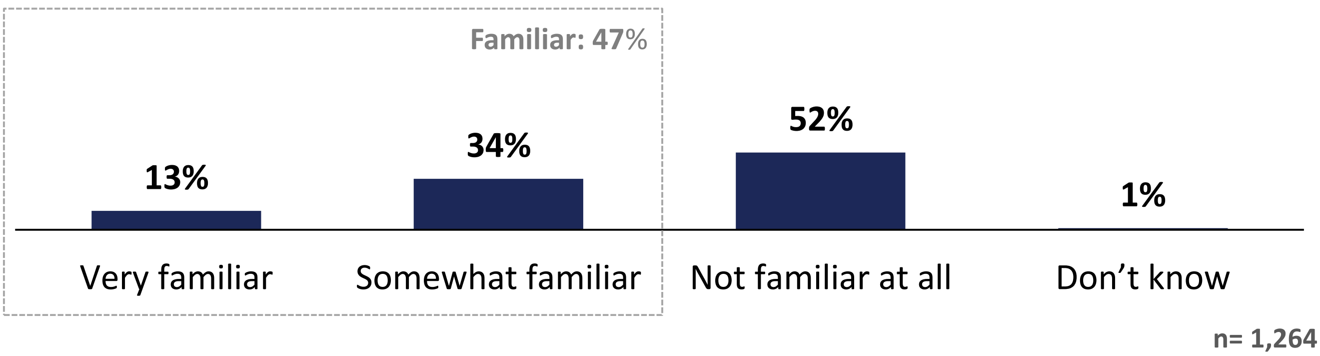
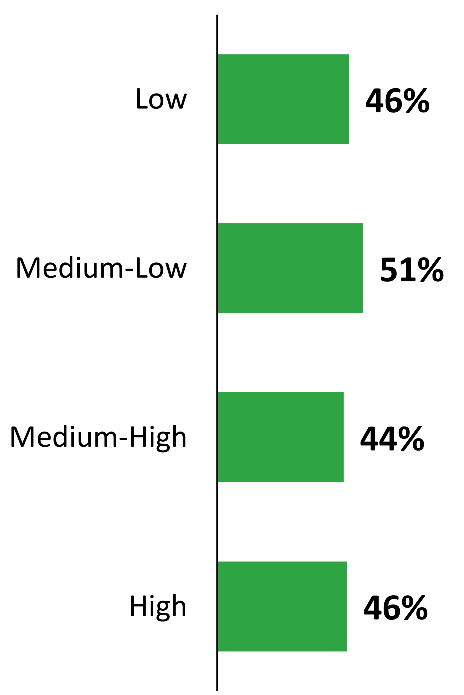
Q Before this survey, how familiar were you with the amount of your electricity bill that went to Niagara Peninsula Energy?

niagara peninsula energy inc. *Your Local Utility*



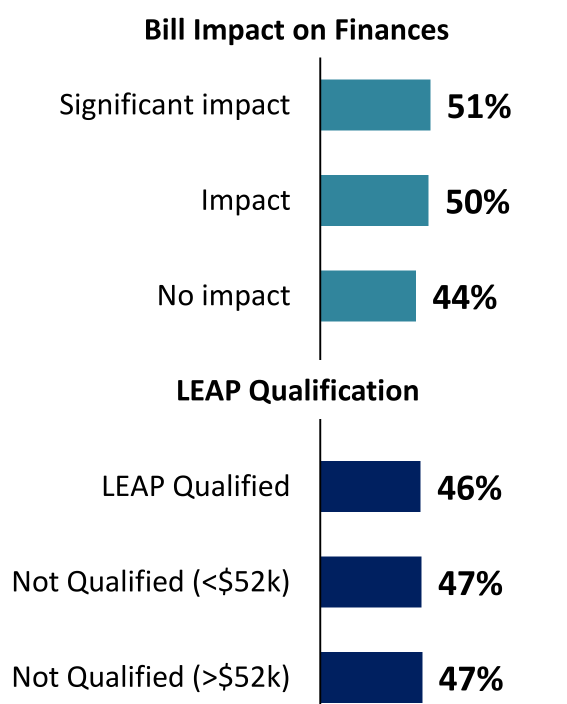
Consumption Segmentation

Respondents who say "Familiar"



Vulnerable Customer Segmentation

Respondents who say "Familiar"



Representative Workbook

How can NPEI Improve services?

Residential

Q Is there anything in particular you would like Niagara Peninsula Energy to do to improve its services to you?

Improving Services (n=401) 68% of respondents did not provide additional feedback	**%**
Improve reliability/less outages	16%
No issues/satisfied with service/keep up the good work	14%
Lower rates/Charge less	12%
Improve billing - clarity/payment terms/methods/website	6%
Invest in infrastructure/move cables underground	6%
Do not increase rates/keep rates affordable	4%
Decrease/eliminate delivery charges	4%
Provide more info on energy consumption/conservation/renewables	3%
Offer rebates/assistance for low income/seniors	3%
Modify time of use/peak rates	2%
Improve customer service/meter reading	2%
Improve outage communication	2%
Find internal efficiencies/provide info on cost cutting	2%
Maintain lines/improve tree clearing	1%
Other	1%
None	20%
Don't Know	2%

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Niagara Peninsula Energy Background

Building Niagara Peninsula Energy's draft plan

NPEI has put together its draft business plan based on the information and input from various sources, such as:

- **Legal and regulatory** requirements by continuing to meet its obligations.
- **Internal business planning** based on expert analysis and professional judgment to develop construction and operations programs that address safety, business, technical, and operational needs.
- **Customer feedback** collected through both ongoing dialogues and specific engagements, such as this.

There are three key organizations responsible for setting the policy direction of Ontario's electricity system. The decisions made by these organizations impact how utilities operate their businesses and serve their customers.

- **Policy**: The Ontario Ministry of Energy, Northern Development and Mines (MNDM) creates energy policy for the province.
- **Regulation**: The electricity industry in Ontario is regulated by the Ontario Energy Board (OEB). One of the OEB's roles is to review the business and distribution plans of all electricity distributors and approve the rates that they charge customers.
- **Operations and Planning**: The Independent Electricity System Operator (IESO) manages the provincial electricity grid, plans for the province's future energy needs, and develops conservation programs.

Ontario ENERGY /ÉNERGIE

ONTARIO ENERGY BOARD

ieso Connecting Today. Powering Tomorrow.

Niagara Peninsula Energy Background

How did customer feedback shape Niagara Peninsula Energy's draft plan?

NPEI is placing more emphasis on incorporating customer feedback into the planning process than ever before.

NPEI engages with its customers both in day-to-day interactions and in a variety of customer engagement activities. These interactions help identify customer needs and preferences, and inform how the utility plans for the future.

This past summer, NPEI engaged with **thousands of residential and business customers** from across its service territory – both in person and through telephone and online surveys.

What did NPEI hear from customers like yourself?

1. The clear majority of NPEI residential and small business customers are satisfied with the current service they receive. When asked how NPEI can improve service, top responses for residential customers were "nothing", followed by "lower or reduce rates".

2. Among competing outcomes, **price**, **reliability**, and **finding internal cost efficiencies** are the top three priorities for both residential and small business customers.

3. While keeping price at a reasonable and affordable level is an important priority, many customers feel that investing in the grid to maintain reliability, is preferable to deferring investments to keep bills low.

Considering this feedback, as well as the information and inputs discussed on the previous page, NPEI has developed a draft plan that is responsive to:

1. Legal requirements by continuing to meet its obligations, including safety and reliability;

2. A transformer station upgrade to accommodate the new Niagara South Hospital and future surrounding growth.

3. Mandatory service connections to accommodate new customers and customer-required upgrades, of which NPEI does not have control over how and when these costs are incurred.

4. Customer feedback by:

    a) Keeping distribution price increases as low as possible;

    b) Maintaining long-term performance for customers experiencing average or better service;

    c) Improving service levels for customers experiencing below average service or who have special reliability needs (e.g. hospitals); and,

    d) Balancing other customer priorities (e.g. customer service) with the need to contain rate increases.

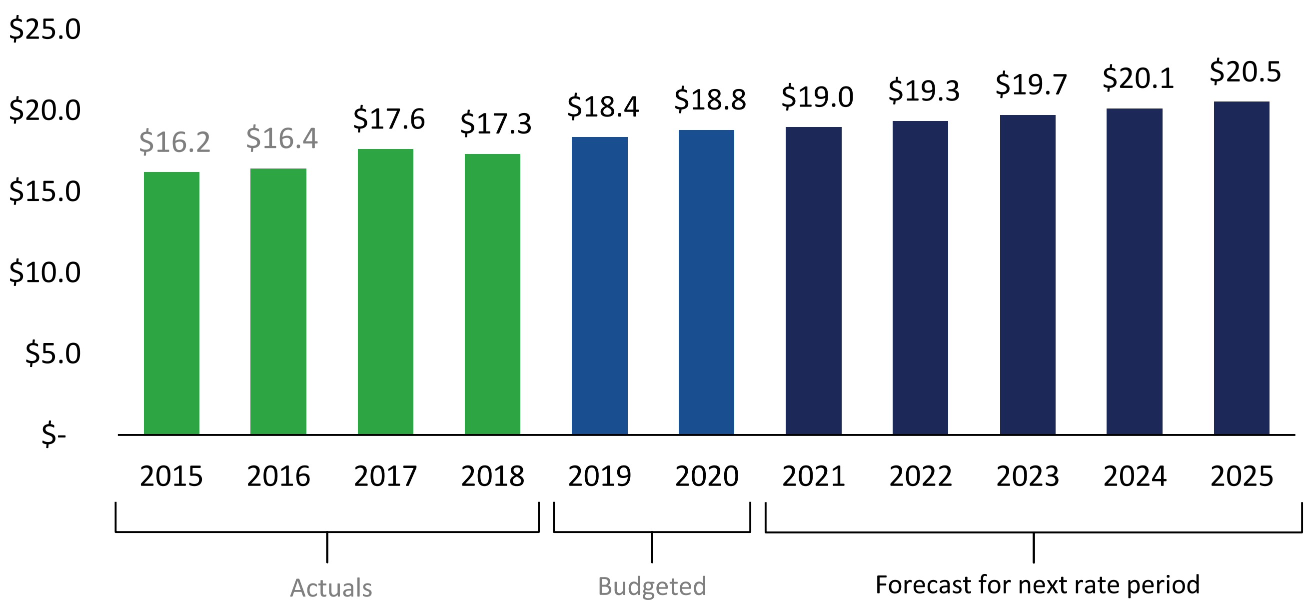
Niagara Peninsula Energy Background

Operating Expenses

In this section, we want to focus on operating expenses and how NPEI compares to its peers.

NPEI's operating budget covers recurring expenses, such as the maintenance of poles, wires, transformers, fleet and buildings as well as proactive maintenance programs such as tree trimming, and payroll for employees. Meter reading, postage, cyber security and hardware/software maintenance expenses are billing and customer service-related expenses. The proposed 5-year plan, between 2021 and 2025, would see NPEI spend an estimated total of $98.7 million on operations.

NPEI's Current and Forecasted Operating Expenses, per Year (Millions)*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

NPEI's **operating costs** are benchmarked by the OEB against other utilities in Ontario. In the last year of publicly available data collected by the OEB, NPEI's operating costs per customer was **$311.67**, which is slightly more than some, while less than both Hydro One and Canadian Niagara Power.

2018 Operating & Maintenance and Administration (OM&A) Per Customer ($)

The diverse geographical nature of NPEI's service territory, which is a mix of urban and rural communities is a large consideration/driver of these OM&A costs. In some parts of the service territory, there may be less than 30 customers per kilometer of line. Despite low density, these lines still require the same level of ongoing maintenance, including tree trimming and other expenses that contribute to operating the system; thereby resulting in a higher cost per customer.

Niagara Peninsula Energy Background

Operating Expenses

Recall, this customer feedback portal does not ask questions that expect you to be an electricity expert.

The OEB runs an open and transparent review process where experts from the OEB and intervenor groups review and challenge NPEI's analyses and assessments. You are welcome to participate in the OEB process if you are interested in those issues. Details can be found at oeb.ca/participate.

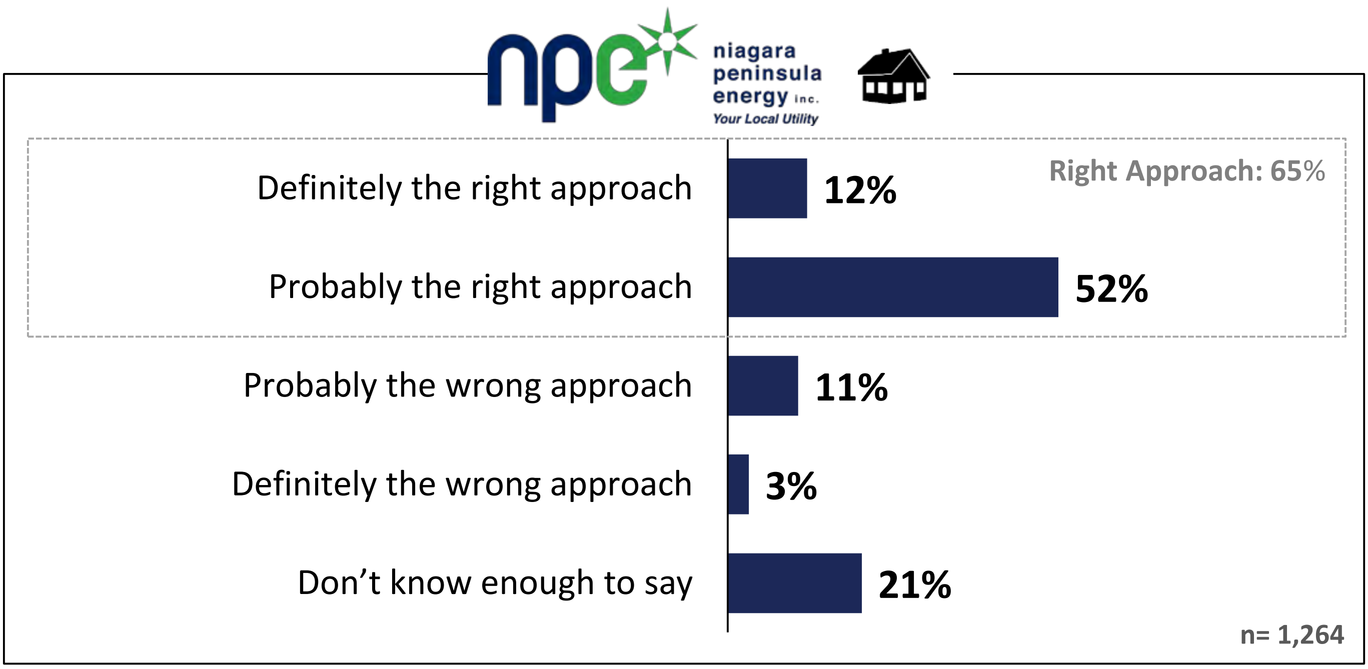
This customer engagement however, is focused on capital investments.

Detailed discussion of NPEI's operating budget is left to experts from the OEB and intervenors in the formal rate application review; this workbook focuses on collecting your view on competing trade-offs in capital investments.

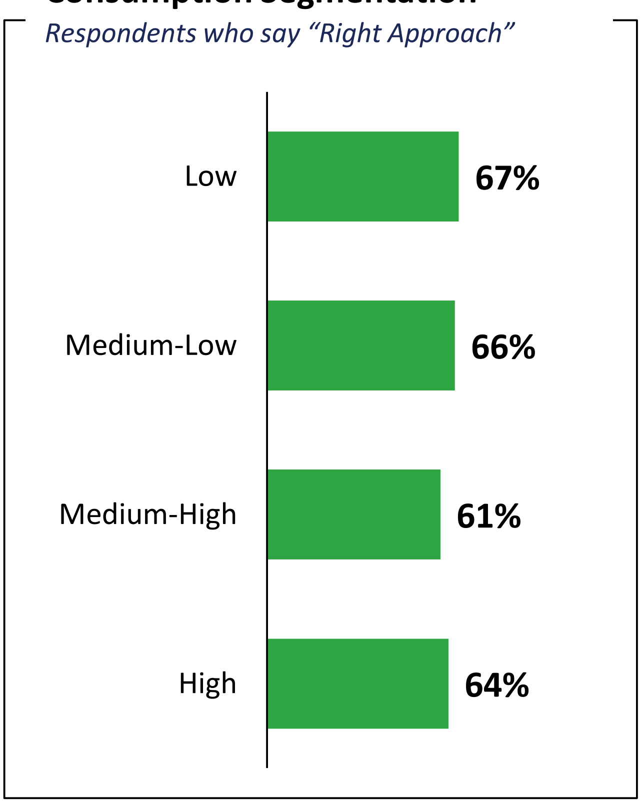
Representative Workbook

Approach to Operating Expenses

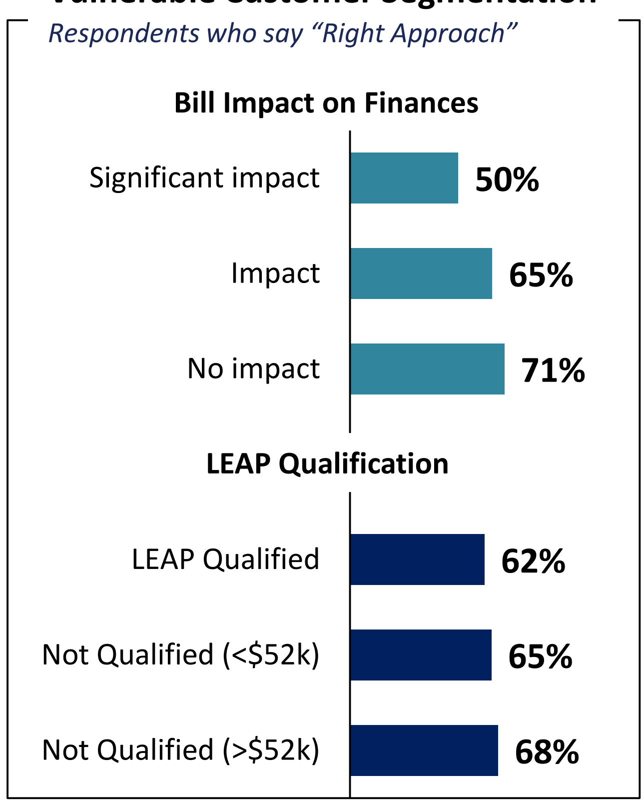
Q Does leaving the detailed discussion about Niagara Peninsula Energy's operating budget to experts from the OEB and intervenors seem like the right approach or wrong approach to you?



Consumption Segmentation



Vulnerable Customer Segmentation



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Niagara Peninsula Energy Background

Capital Investments

NPEI's **capital budget** covers items that, once purchased, have lasting benefits over many years. Year-over-year, regardless of external drivers, NPEI will need to make investments in the core distribution system, including poles, wires, cables and transformers.

Based on initial customer input and the approach outlined previously, NPEI believes the capital expenditure required to address system renewal, maintain system reliability and safety, and invest in other infrastructure priorities between 2021 and 2025 is estimated to be **$70.3 million**.

NPEI classifies the costs of four types of capital investment between 2021 and 2025. Each of these four investment categories helps NPEI pace and prioritize projects.

2021-2025 Forecasted Capital Investments

System Renewal ($38.2 million)

These projects are a mix of planned end-of-life replacements and emergency replacements.

Projects Include: Replacement of existing overhead wires, poles, and pole mounted transformers, underground cables and transformers and transformer station upgrades.

System Access ($17.1 million)

"Must do" investments that respond to customer requests for new connections or new infrastructure development.

Projects Include: NPEI's share of new subdivisions, new upgraded commercial and industrial services, and relocating assets based on road infrastructure needs.

General Plant ($8.4 million)

These are investments needed to support the distribution system, such as tools, vehicles, buildings, and computers.

Projects Include: Financial and customer IT systems, enhanced cyber security investments, facility renovations, backup generation, and vehicle replacements.

System Service ($6.6 million)

These investments consist of projects that address capacity constraints, improve system reliability and customer service.

Projects Include: Installation of automated switches and system expansion to supply new development.

Niagara Peninsula Energy Background

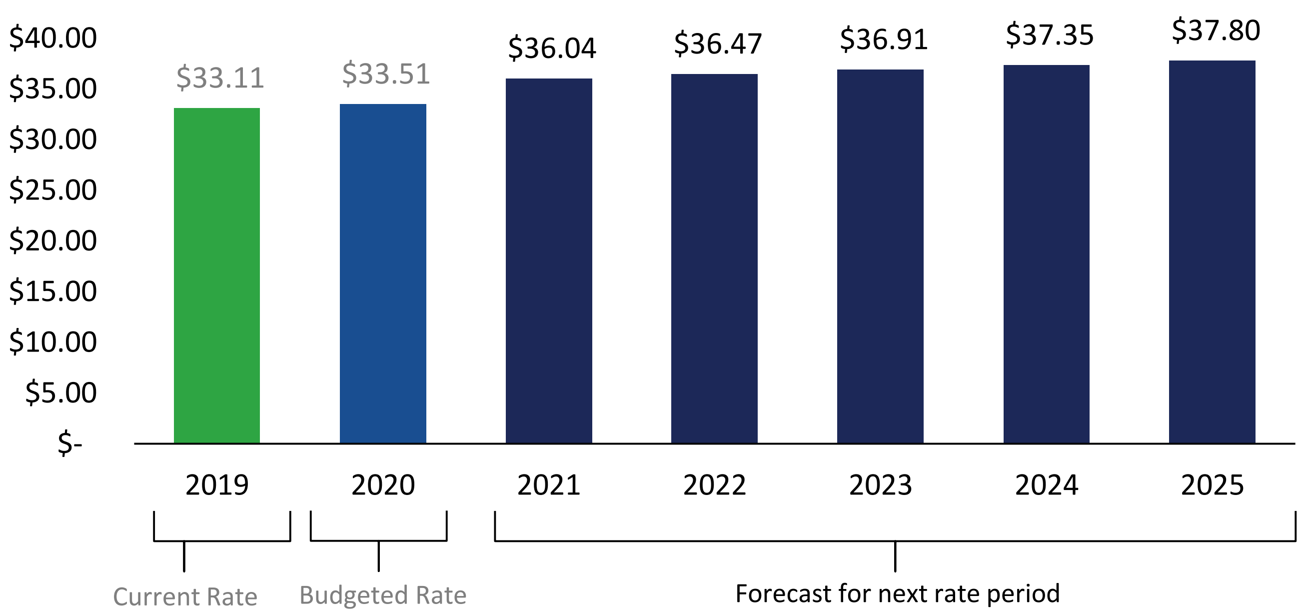
How much will this draft plan cost me?

Remember, the current typical NPEI residential customer's electricity bill is about $113 per month, of which $33.11 goes to NPEI.

It is estimated that if NPEI continues with its preliminary plan, the distribution portion of the bill will increase by $2.53 per month in 2021, when the plan is set to come into effect. For the period 2022-2025, the annual bill increase is limited by the OEB to be less than the rate of inflation.

- At the end of the 5-year plan, the typical residential customer would see the distribution portion of their electricity bill increase by $4.29.
- As a result, the distribution charges on the typical residential customer's monthly bill would increase from $33.51 in 2020 to $37.80 by 2025.

Estimated Residential Monthly Distribution Charge, per Year*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

NPEI is looking for your input on its preliminary plan to ensure it is making the spending decisions that matter to you, the customer.

The following sections of this workbook will explore some of the choices Niagara Peninsula Energy needs to make to help finalize its preliminary plan.

Representative Workbook

Background Information

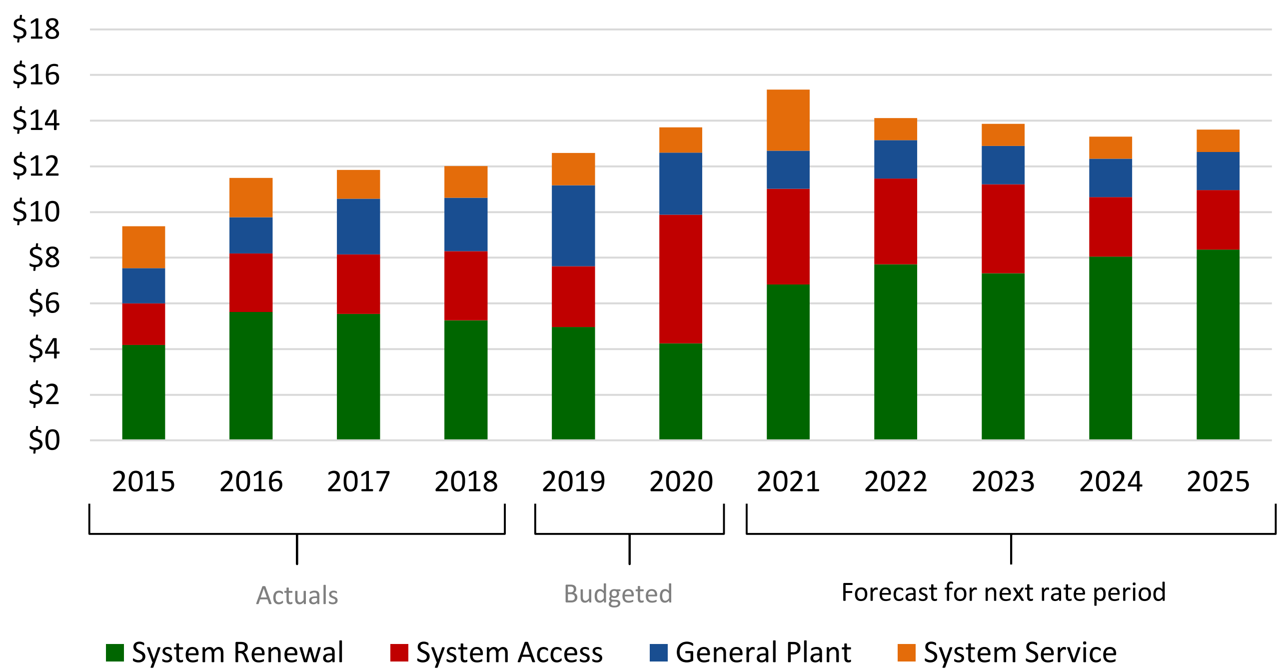
Niagara Peninsula Energy Background

Pacing Capital Investments

The overall amount NPEI invests in capital projects remains generally the same year over year, but what does change is where these investments are made. In some years, when unplanned or unforeseen investments are needed, NPEI will re-allocate funds to make room for these projects within the approved budget. This helps limit the overall amount that the distribution charges fluctuate year-over-year.

The chart below outlines NPEI's spending in past years, and proposed spending for the 5-year period 2021 to 2025.

2015 – 2025 Historical and Forecasted Capital Investments*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

System Access expenditures are budgeted to increase to $5.6M in 2020 to accommodate a number of large commercial customer growth projects as well as municipal road work.

Representative Workbook

Approach to Pacing Investments

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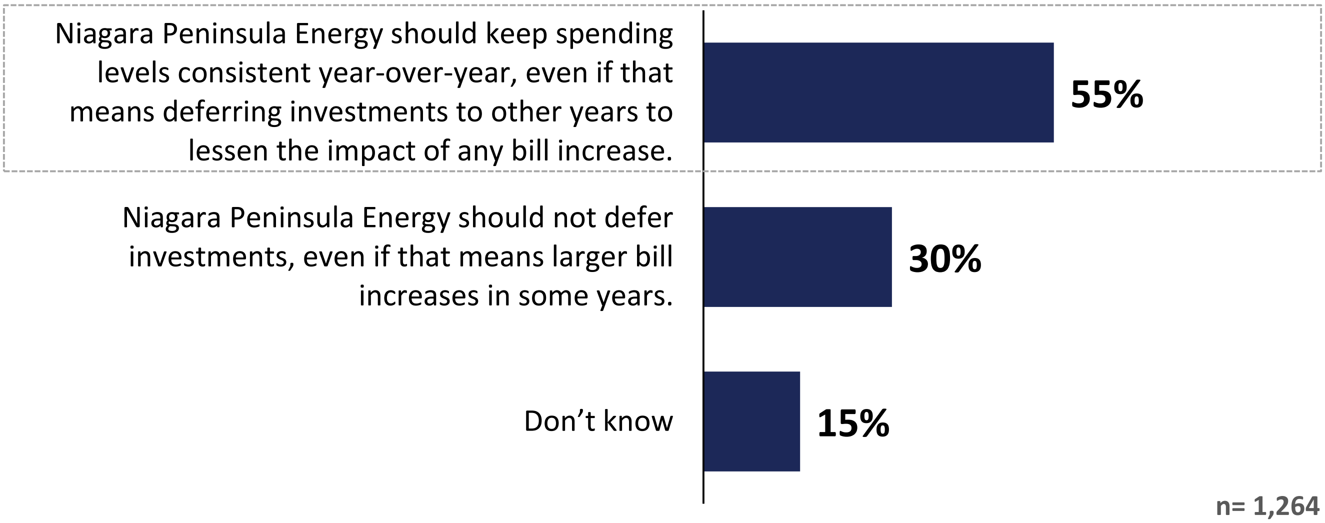
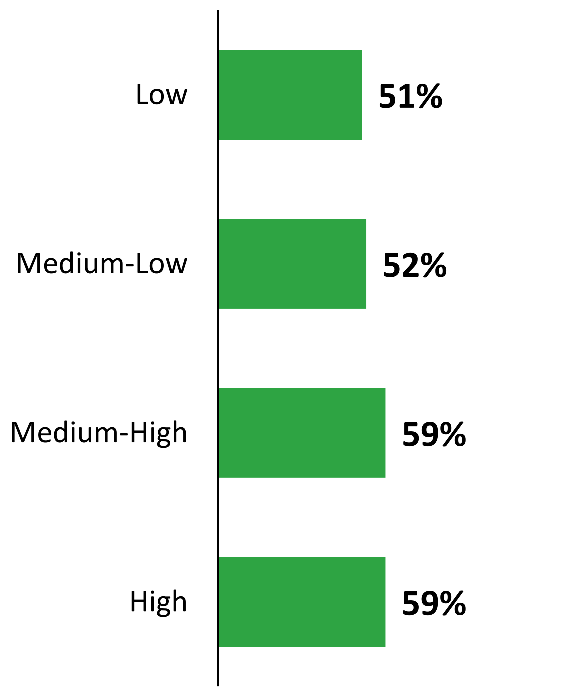
Q Which of the following statements best represents your point of view regarding Niagara Peninsula Energy's approach to pacing investments?



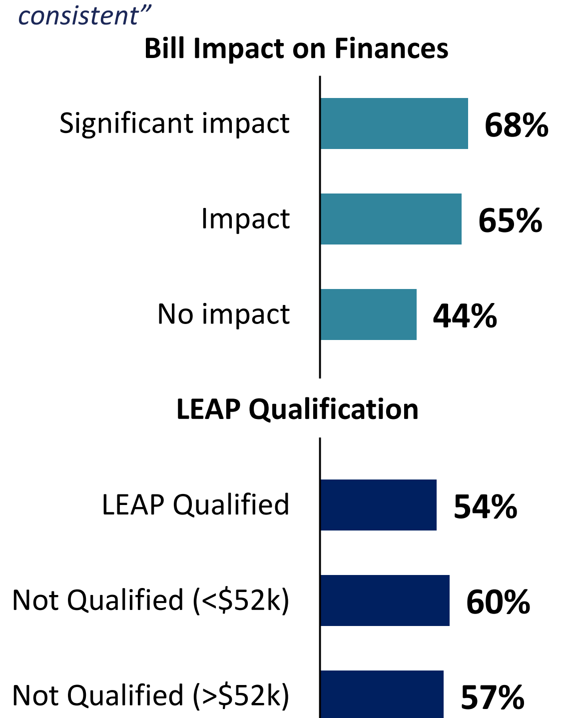
Consumption Segmentation

Respondents who say "Keep spending consistent"



Vulnerable Customer Segmentation

Respondents who say "Keep spending consistent"



Representative Workbook

Residential

Additional Feedback: Approach to Pacing Investments

Q Additional Feedback (Optional)

Additional Feedback (n=163) 87% of respondents did not provide additional feedback	**%**
Rate increases should at a reasonable stable rate/ small increases over time when necessary	23%
Deferring only increases future prices/invest now in technology and equipment	23%
No increase-keep cost low too high already	17%
Cost should be incurred by/Builders/developers/Government	13%
Find efficiencies/cost savings/use profits/capital investments	6%
Case by case basis/Prioritize spending on what is needed most	4%
Reliability of services is paramount	2%
Other	9%
None	3%
Don't know	1%

Niagara Peninsula Energy Background

Mandatory Investments

Federal, provincial, and municipal governments as well as regulators set requirements and standards that NPEI must satisfy. Mandatory investments can be broken down into three categories:

- **Connecting customers**: This includes connecting customers to the grid when a new home or building is constructed or modified.
- **Moving equipment**: This includes moving equipment like poles and cables for road widening.
- **Mandated obligations**: This includes installing and maintaining customer meters and transferring electricity from the provincial transmission system.

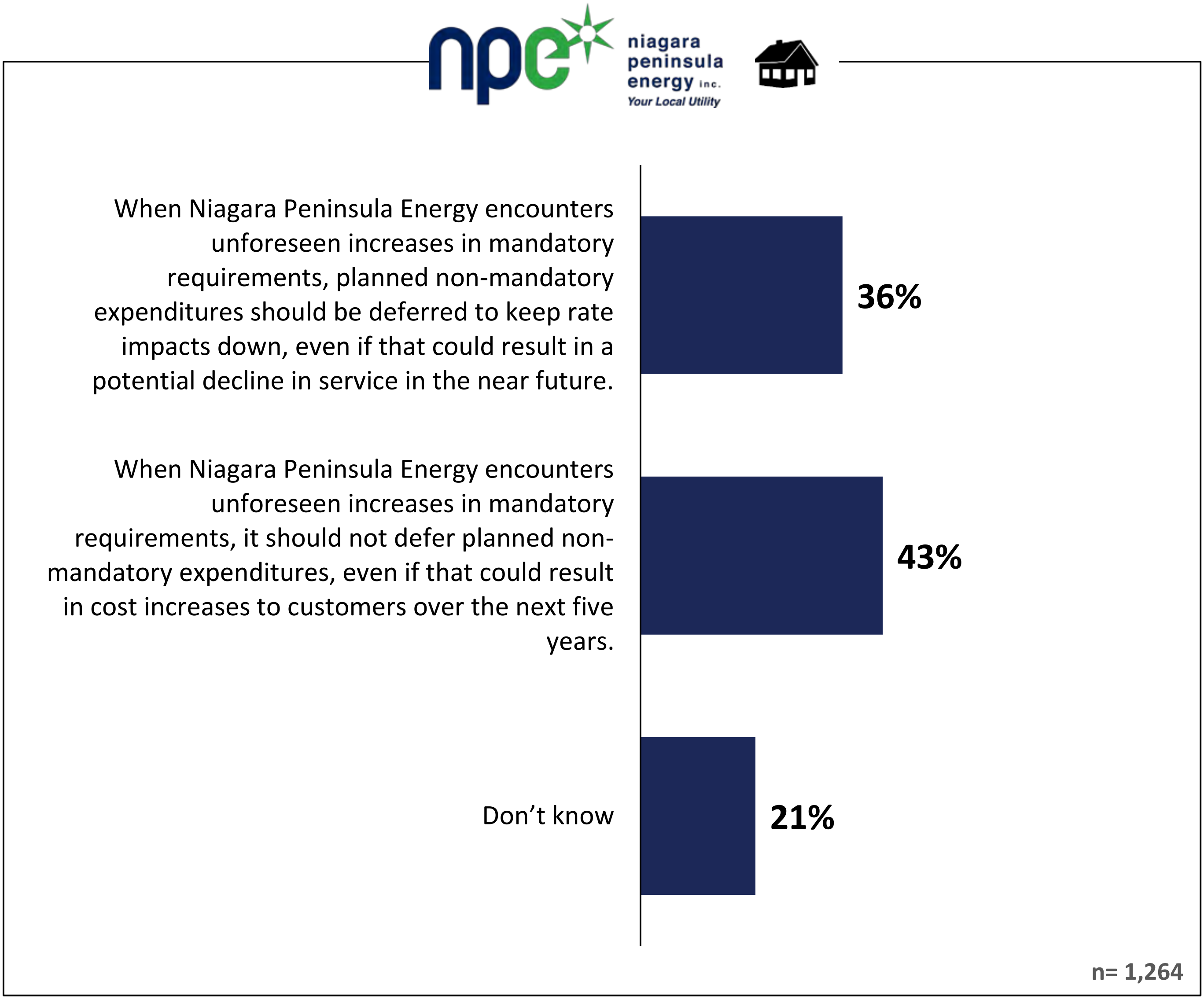
These mandatory investments mean that about **one-in-four dollars (23%)** of your distribution rates over the past five years have not been available for other non-mandatory investments. Looking forward to the 2021-2025 period, NPEI forecasts a similar level of mandatory investments, driven largely by:

- **Preparing to connect the new Niagara South hospital;**
- **Work to accommodate the 2021 Canada Summer Games in the Niagara Region, and;**
- **Work to accommodate growth and future electricity capacity needs.**

Representative Workbook

Approach to Mandatory Investments

Q Which of the following statements best represents your point of view regarding Niagara Peninsula Energy's approach to mandatory and non-mandatory spending?



Representative Workbook

Residential

Additional Feedback: Approach to Mandatory Investments

Q Additional Feedback (Optional)

Additional Feedback (n=154) 88% of respondents did not provide additional feedback	**%**
Case-by-case basis/New developers/builders/Company/2021 Canada Games/Government-should fund costs	31%
Increase within reason when expenditures are necessary/Balance over 5 years	23%
Unforeseen increases should not be encountered / impact services -Plan better/should already be in budget	22%
Keep rates low/Cost is already to high-no increase	8%
When issues are resolved rates should be decreased	4%
Cut back on salaries/operating costs	1%
Other	10%
None	1%

Representative Workbook

Background Information

Making Choices (1 of 7)

Overhead Pole Replacement

A recent asset health condition assessment shows that **575 or approximately 3%** of the poles in NPEI's distribution system are in *poor* or *very poor* condition. Each year, new poles enter this condition, and NPEI takes an approach that proactively replaces poles as to not create a large backlog. As a general rule, pole failure only causes an outage when something happens outside of the utility's control, most frequently due to trees knocking them down or a car accident.

On average, since 2014, NPEI has replaced approximately 88 poles per year. This pace has effectively maintained reliability over this period.

NPEI is proposing to replace most of these 575 poles in poor and very poor condition over the course of the next five years, however, there is an opportunity to replace these poles more quickly or slowly. NPEI must continue to invest in overhead pole replacement, therefore, this is a matter of whether customers would rather pay more during the upcoming period, or push some level of investment beyond the next five years.

Option	Poles Replaced	Expected Outcome
Accelerated Pace ***Additional*** *$0.03 per month annually ($0.36 more per year)*	1,000 by 2025 (200 per year)	Address the very poor and some of the poor condition poles identified in the Asset Condition Assessment.
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	500 by 2025 (100 per year)	Address most of the very poor condition poles identified in the Asset Condition Assessment and annual pole inspections by 2025.
Slower Pace ***Decrease*** *of $0.01 per month annually ($0.12 less per year)*	250 by 2025 (50 per year)	Address only the poles in need of immediate replacement, as identified in the annual pole inspection report.

INNOVATIVE RESEARCH GROUP

Representative Workbook

Overhead Pole Replacement

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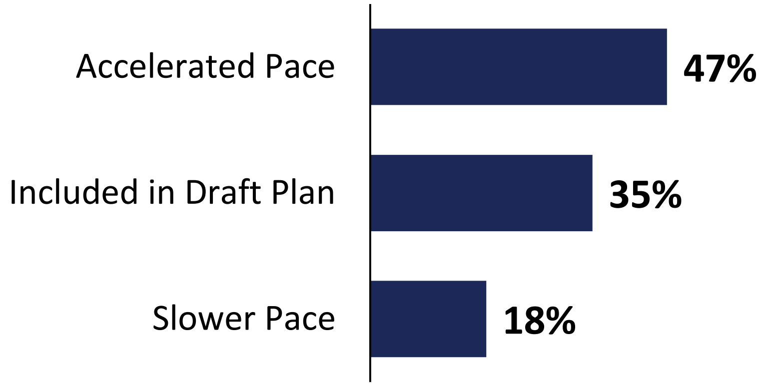
Q Which of the following options do you prefer?



n= 1,264

Regional Segmentation	Niagara Falls/Pelham	Lincoln	West Lincoln
Accelerated Pace	47%	42%	51%
Included in Draft Plan	34%	42%	31%
Slower Pace	19%	16%	18%

Bill Impact on Finances	Significant impact	Impact	No Impact
Accelerated Pace	32%	44%	55%
Included in Draft Plan	25%	38%	36%
Slower Pace	43%	17%	9%

LEAP Qualification	LEAP Qualified	Not Qualified (<$52k)	Not Qualified (>$52k)
Accelerated Pace	37%	41%	53%
Included in Draft Plan	30%	38%	36%
Slower Pace	33%	22%	11%

Representative Workbook

Additional Feedback: Overhead Pole Replacement

Q Additional Feedback (Optional)

Additional Feedback (n=138) 89% of respondents did not provide additional feedback	**%**
Bury lines/better to replace with underground lines	21%
Be proactive/pay now to save later/costs will only increase	20%
Reliability/safety outweighs cost	13%
Investigate/Invest in new pole technology	6%
Replace within budget/no increase to consumer	6%
Information misleading/skeptical about figures/inspection criteria	6%
Replace as necessary/most urgent first/my street first	5%
Issue due to poor management/maintenance should have been ongoing	4%
New developments/drivers involved in accidents should be responsible	3%
Extreme weather events should make this a priority	3%
Cost acceptable	2%
Need more information	1%
Coordinate with other services/find other revenue streams	1%
Other	2%
None	5%
Don’t know	1%

Making Choices (2 of 7)

Overhead transformer replacement

Transformers are a critical piece of distribution equipment that reduce voltage from the higher levels that are more efficient to move electricity long distances to lower levels that are safer to connect to homes and businesses. They are typically either located on the ground, in underground vaults, or attached to distribution poles

A recent asset health condition assessment shows that **1,251 or approximately 21%** of the overhead transformers in NPEI's distribution system are in poor or very poor condition.

Since 2014, overhead transformer failure has directly resulted in approximately 15 outages per year. That said, in most cases, when an overhead transformer fails, it only impacts a small amount of customers and the equipment can be replaced within 2-3 hours depending on the circumstances.

However, when these outages do occur, it can take NPEI crews an extended period of time to replace the cable and restore power to affected households and businesses.

NPEI is proposing a new program to proactively replace **250 of the 677 or 37%** of the overhead transformers identified as very poor condition before they fail over the course of the next five years.

As with distribution poles, NPEI will proactively invest in overhead transformer replacement, therefore, this is a matter of whether customers would rather pay more during the upcoming period, or push some level of investment beyond the next five years.

Option	**Transformers Replaced**	**Expected Outcome**
Accelerated Pace ***Additional*** *$0.01 per month annually ($0.12 more per year)*	375 by 2025 (75 per year)	Address some of the polemount transformers identified as very poor in the Asset Condition Assessment report.
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	250 by 2025 (50 per year)	Address some of the polemount transformers identified as very poor in the Asset Condition Assessment report.
Slower Pace ***Decrease*** *of $0.01 per month annually ($0.12 less per year)*	125 by 2025 (25 per year)	Address only the worst of the polemount transformers identified as very poor in the Asset Condition Assessment report.

Representative Workbook

Overhead transformer replacement

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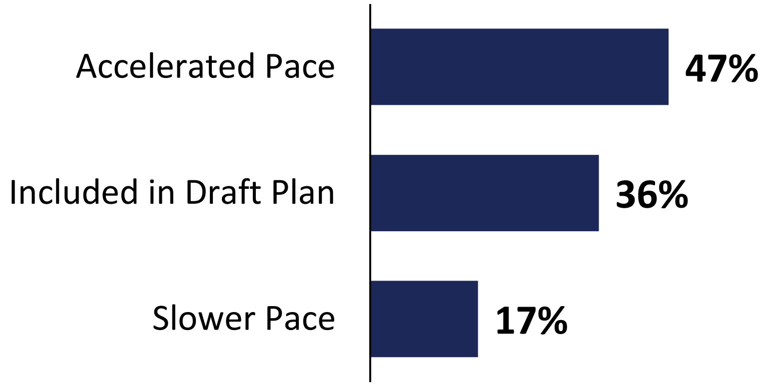
Q Which of the following options do you prefer?



n= 1,264

Regional Segmentation	Niagara Falls/Pelham	Lincoln	West Lincoln
Accelerated Pace	47%	47%	46%
Included in Draft Plan	34%	40%	40%
Slower Pace	19%	13%	14%

Bill Impact on Finances	Significant impact	Impact	No Impact
Accelerated Pace	31%	42%	57%
Included in Draft Plan	30%	40%	35%
Slower Pace	38%	18%	8%

LEAP Qualification	LEAP Qualified	Not Qualified (<$52k)	Not Qualified (>$52k)
Accelerated Pace	38%	41%	53%
Included in Draft Plan	31%	40%	37%
Slower Pace	31%	19%	11%

Representative Workbook

Residential

Additional Feedback: Overhead transformer replacement

Q Additional Feedback (Optional)

Additional Feedback (n=99) 92% of respondents did not provide additional feedback	**%**
Replace with underground/more secure alternative	20%
Reliability/safety outweighs cost	13%
Be proactive/pay now to save later/costs will only increase	8%
Replace as necessary/most urgent/poor transformers first	8%
Issue due to poor management/maintenance should have been ongoing	7%
Replace within budget/find efficiencies/no increase to the consumer	6%
Need more information	4%
Data/figures questionable	3%
Cost acceptable/negligible	3%
Keeping consumer costs low should be a priority/cost already high	2%
Outages acceptable	2%
Only affected customers should pay	1%
Coordinate with pole replacement	1%
Other	1%
None	18%
Don't Know	1%

INNOVATIVE RESEARCH GROUP

Making Choices (3 of 7)

Converting Outdated Underground Kiosk Transformers

NPEI's system features a type of underground transformer that was popular in the 1940s to 1970s which no longer meets construction and safety standards. While this equipment still functions, it is becoming increasingly difficult to safely and effectively maintain. When this equipment does fail, it can result in lengthy outages due to the limited accessibility due to the original method of construction.

On average, since 2014, NPEI has converted approximately 9 kiosk transformers per year. Between 2018 and 2019, the pace of this program has been pushed off, and today, there remains 75 transformers in need of replacement.

NPEI is proposing to convert all of this equipment within the next seven years, with 55 being converted in the next five year period. That said, there is an opportunity to convert these kiosk transformers more slowly.

Option	Transformers Installed	Expected Outcome
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	55 by 2025 (11 per year)	Work towards eliminating all old installations over the next 7 years.
Reduced Pace ***Decrease*** *of $0.02 per month annually ($0.24 less per year)*	25 by 2025 (5 per year)	Work towards eliminating all old installations over the next 15 years.
Slower Pace ***Decrease*** *of $0.03 per month annually ($0.36 less per year)*	10 by 2025 (2 per year)	Work towards eliminating all old installations over the next 35 years.

Representative Workbook

Converting Outdated Underground Kiosk Transformers

Niagara Peninsula Energy Inc.
EB-2020-0040
Filed: August 31, 2020
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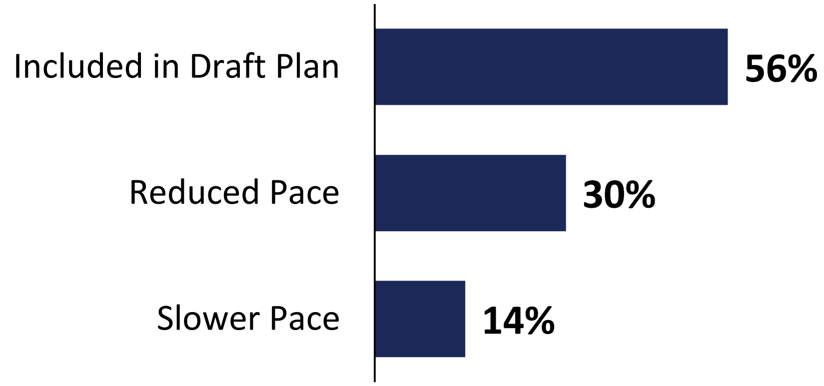
Q Which of the following options do you prefer?



n= 1,264

Regional Segmentation	Niagara Falls/Pelham	Lincoln	West Lincoln
Included in Draft Plan	55%	61%	49%
Reduced Pace	29%	29%	37%
Slower Pace	15%	10%	15%

Bill Impact on Finances	Significant impact	Impact	No Impact
Included in Draft Plan	27%	53%	69%
Reduced Pace	37%	33%	25%
Slower Pace	36%	14%	6%

LEAP Qualification	LEAP Qualified	Not Qualified (<$52k)	Not Qualified (>$52k)
Included in Draft Plan	42%	52%	63%
Reduced Pace	35%	32%	27%
Slower Pace	24%	16%	10%

Representative Workbook

Additional Feedback: Underground Kiosk Transformers

Q Additional Feedback (Optional)

Additional Feedback (n=75) 94% of respondents did not provide additional feedback	**%**
Reliability/safety outweighs cost	22%
Replace as necessary/most urgent/outdated first/run to fail	13%
Be proactive	9%
Need more information	8%
Replace within budget/find efficiencies/no increase to the consumer	7%
Issue due to poor management/maintenance should have been ongoing	6%
Only affected customers should pay	5%
Improve infrastructure	4%
Other	4%
None	17%
Don't Know	6%

Making Choices (4 of 7)

Underground cable replacement

Many neighbourhoods across NPEI's service territory are serviced by underground cables. Historically, NPEI has taken a "run-to-failure" approach with this equipment; that is, a cable will be replaced only once it has failed. The age of this equipment is now becoming a concern, with approximately 78 km or 18% of underground cable operating beyond its estimated useful life of 35 years.

Since 2014, underground cable failure has directly resulted in approximately ten outages per year, and when these outages do occur, it can take NPEI crews an extended period to replace the cable and restore power to affected households and businesses.

Between 2021 and 2025, NPEI is proposing a new program that will replace cable that has been identified as past end of life when completing other associated work. NPEI believes that this could help reduce the number and length of outages caused by underground cable failure, as well as to start getting ahead of the ongoing age issue. That said, there is an opportunity to take a more proactive approach to addressing some of the older cable in the system.

Option	**Km of cable installed**	**Expected Outcome**
Further Accelerated Pace ***Additional*** *$0.13 per month annually ($1.56 more per year)*	24 km by 2025 (4.8 km per year)	Proactively replace more of the cables identified as past end of life in the Asset Condition Assessment Report.
Accelerated Pace ***Additional*** *$0.06 per month annually ($0.72 more per year)*	12 km by 2025 (2.4 km per year)	Proactively replace some of the cables identified as past end of life in the Asset Condition Assessment Report.
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	2 km by 2025 (0.4 km per year)	Replace cables past end of life as other work is being completed on associated switchgear or riser poles.

Representative Workbook

Underground cable replacement

Niagara Peninsula Energy Inc.
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Filed: August 31, 2020
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Q Which of the following options do you prefer?

n= 1,264

Regional Segmentation	Niagara Falls/Pelham	Lincoln	West Lincoln
Further Accelerated Pace	31%	27%	23%
Accelerated Pace	37%	37%	30%
Included in Draft Plan	32%	36%	47%

Bill Impact on Finances	Significant impact	Impact	No Impact
Further Accelerated Pace	27%	24%	34%
Accelerated Pace	31%	39%	37%
Included in Draft Plan	43%	37%	29%

LEAP Qualification	LEAP Qualified	Not Qualified (<$52k)	Not Qualified (>$52k)
Further Accelerated Pace	34%	23%	32%
Accelerated Pace	32%	40%	36%
Included in Draft Plan	34%	37%	32%

Representative Workbook

Residential

Additional Feedback: Underground cable replacement

Q Additional Feedback (Optional)

Additional Feedback (n=69) 95% of respondents did not provide additional feedback	**%**
Be proactive/pay now to save later/costs will only increase	13%
Invest in new cable technology/extend cable life	11%
Reliability/safety outweighs cost	11%
Issue due to poor management/maintenance should have been ongoing	10%
Need more information	8%
Replace as necessary/most urgent first	8%
Improve cable assessments/more investigation required	7%
Coordinate with other services	5%
Bury lines/better to replace with underground lines	4%
Replace within budget/no increase to consumer/cash grab	4%
Only affected customers should pay	3%
Other	1%
None	11%
Don't Know	3%

Making Choices (5 of 7)

Subdivision underground rehabilitation

71 of the subdivisions in NPEI's service territory were constructed with **direct buried cable** which refers to a type of construction where cables are laid directly in underground trenches without a protective barrier.

While this was typical construction at the time, 40 of these subdivisions were built 40 or more years ago, and the cables are now approaching the end of their recommended life.

In this upcoming plan, NPEI is proposing a new program to start preparing to upgrade the service in the subdivisions with the most pressing needs.

In order to keep costs down, NPEI is proposing to start rehabilitation of the underground "system" by installing ducts that will eventually carry underground cables over the next five years. The cables would be installed as needed (upon failure) or once all of the old subdivisions have had the duct installed.

Completing this work in two phases will not only save costs now, but also help ensure that NPEI will be able to rehabilitate the most subdivisions in the shortest time.

Between 2021 and 2025, NPEI is proposing a new program that will proactively install ducts in approximately 10 subdivisions. Which subdivisions receive investment first will predominantly be based on age. That said, there is an opportunity to either accelerate or slow down the pace of this new program.

Option	Km of vault installed	Expected Outcome
Accelerated Pace ***Additional*** *$0.02 per month annually ($0.24 more per year)*	30 km by 2025 (6 km per year)	Install 6 km of ducts or approximately four subdivisions per year.
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	15 km by 2025 (3 km per year)	Install 3 km of ducts or approximately two subdivisions per year.
Slower Pace ***Decrease*** *of $0.01 per month annually ($0.12 less per year)*	7.5 km by 2025 (1.5 km per year)	Install 1.5 km of ducts or approximately one subdivision per year.

Representative Workbook

Subdivision underground rehabilitation

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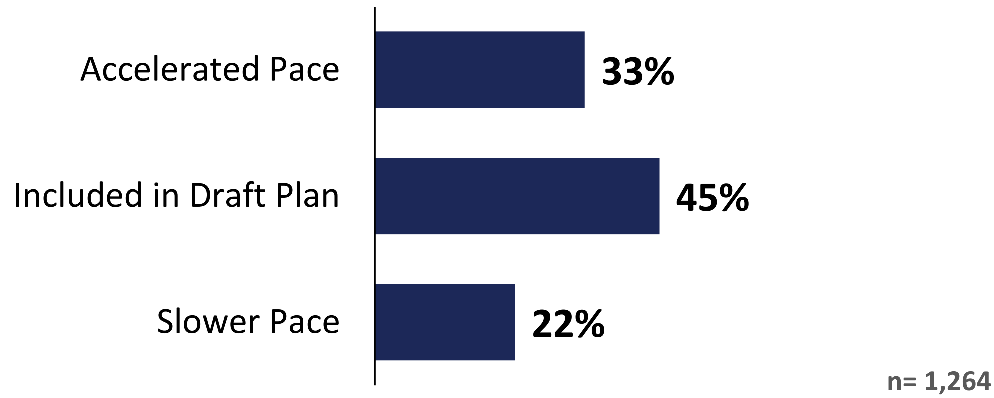
Q Which of the following options do you prefer?



Regional Segmentation	Niagara Falls/Pelham	Lincoln	West Lincoln
Accelerated Pace	35%	30%	23%
Included in Draft Plan	42%	53%	49%
Slower Pace	23%	18%	27%

Bill Impact on Finances	Significant impact	Impact	No Impact
Accelerated Pace	23%	32%	39%
Included in Draft Plan	33%	47%	47%
Slower Pace	45%	20%	14%

LEAP Qualification	LEAP Qualified	Not Qualified (<$52k)	Not Qualified (>$52k)
Accelerated Pace	34%	29%	39%
Included in Draft Plan	33%	46%	44%
Slower Pace	33%	25%	17%

Representative Workbook

Residential

Additional Feedback: Subdivision underground rehabilitation

Q Additional Feedback (Optional)

Additional Feedback (n=54) 96% of respondents did not provide additional feedback	**%**
Charge new developments/Only affected customers should pay	19%
Need more information	13%
Slower pace/investigate in new cable technology/improvements	11%
Replace as necessary/most urgent first	9%
Be proactive/pay now to save later/costs will only increase	9%
Reliability/safety outweighs cost	8%
Issue due to poor management/maintenance should have been ongoing	7%
Information misleading/skeptical about figures/inspection criteria	5%
Bury lines/better to replace with underground lines	5%
Replace within budget/no increase to consumer	2%
None	11%

Overhead rebuilds

Beyond replacing overhead poles, NPEI has a program that rebuilds the overhead system for entire streets and neighbourhoods. This includes poles, wires, and all other equipment that goes into operating the overhead system.

A recent asset health condition assessment identified a total of **60 areas** within NPEI's service territory that require complete overhead rebuilds**.** Most of this equipment is either beyond its recommended age or deteriorated due to weather and other factors. This infrastructure is in addition to the poles identified in the earlier section.

This program is intended to contribute to the "betterment" of the overhead system by;

- Improving system performance by installing animal guards and higher capacity transformers to reduce the likelihood of outages, and;
- Improving system aesthetics with new and taller poles.

On average, each of the projects would replace approximately 30-40 poles, depending on the population density of the area being worked on. NPEI's current approach would rebuild **40 out of 60 areas** in the 2021 to 2025 period.

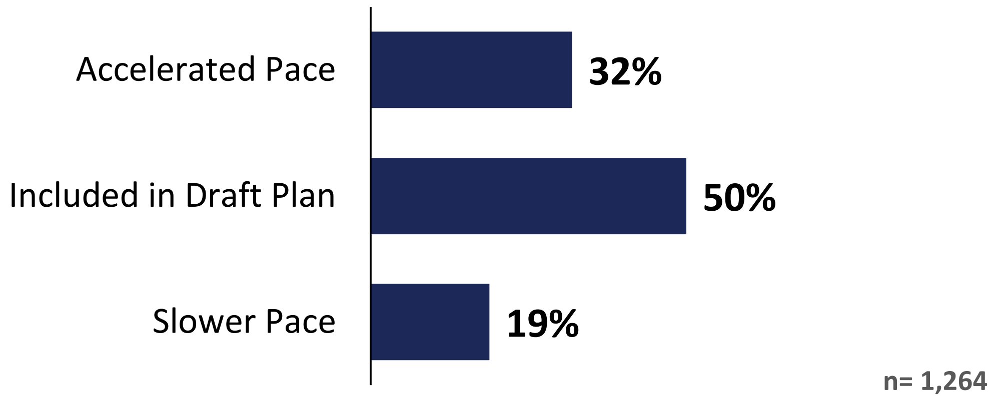
NPEI must continue to invest in overhead rebuilds, therefore, this is a matter of whether customers would rather pay more during the upcoming period or push some level of investment beyond the next five years.

Option	Overhead rebuilds	Expected Outcome
Accelerated Pace ***Additional*** *$0.03 per month annually ($0.36 more per year)*	61 km by 2025 (12.2 km per year)	Rebuild 12.2 km per year or approximately 10 projects per year
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	48.5 km by 2025 (9.7 km per year)	Rebuild areas with assets that have been identified as very poor in Asset Condition Assessment. Rebuild 9.7 km per year or approximately 8 projects per year
Slower Pace ***Decrease*** *of $0.03 per month annually ($0.36 less per year)*	36 km by 2025 (7.2 km per year)	Rebuild 7.2 km per year or approximately 6 projects per year

Representative Workbook

Overhead rebuilds

Q Which of the following options do you prefer?



Regional Segmentation	Niagara Falls/Pelham	Lincoln	West Lincoln
Accelerated Pace	34%	28%	24%
Included in Draft Plan	47%	55%	57%
Slower Pace	19%	17%	19%

Bill Impact on Finances	Significant impact	Impact	No Impact
Accelerated Pace	26%	31%	35%
Included in Draft Plan	39%	50%	53%
Slower Pace	35%	19%	12%

LEAP Qualification	LEAP Qualified	Not Qualified (<$52k)	Not Qualified (>$52k)
Accelerated Pace	33%	27%	37%
Included in Draft Plan	41%	53%	49%
Slower Pace	26%	20%	14%

Representative Workbook

Additional Feedback: Overhead rebuilds

Residential

Q Additional Feedback (Optional)

Additional Feedback (n=52) 96% of respondents did not provide additional feedback	**%**
Bury lines/better to replace with underground lines	35%
Reliability/safety outweighs cost	12%
Need more information	10%
Replace as necessary/most urgent first/run to fail	10%
Improve infrastructure/protect from animals	6%
Coordinate with pole replacement	5%
Replace within budget/find efficiencies/no increase to consumer	5%
Coordinate with other services/find other revenue streams/charge new developments	3%
Issue due to poor management/maintenance should have been ongoing	3%
Other	2%
None	8%

Making Choices (7 of 7)

Grid modernization

New technology has changed the way that NPEI can manage and monitor the distribution system.

Supervisory Control and Data Acquisition (SCADA) systems allow NPEI staff the ability to remotely monitor and trace system faults and re-close switches from a control room rather than sending a repair crew to patrol the lines. These systems are particularly effective where there are larger distances between customers, for instance, in more rural areas of the western region of NPEI's service territory.

This equipment can have significant positive impacts on restoration times when an outage does occur, particularly in instances such as during a severe weather event.

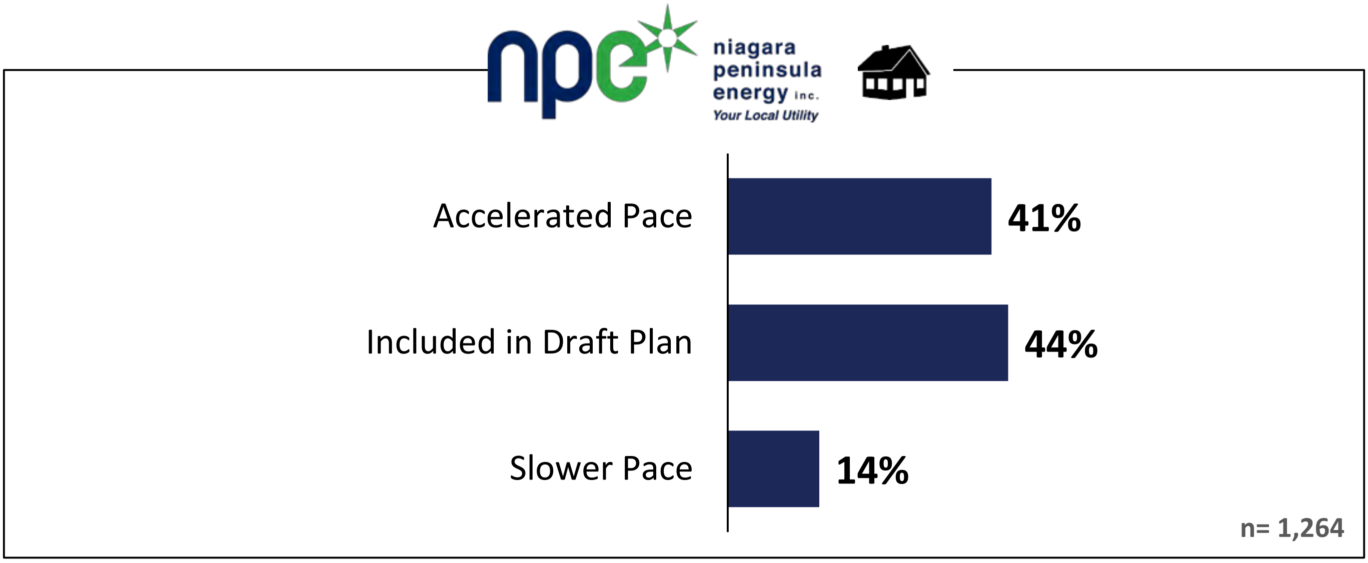
On average, since 2014, NPEI has installing approximately two remote devices per year, with focus on more rural, lower density areas. That said, there is an opportunity to install this monitoring and control equipment more quickly or slowly.

Option	**Devices installed**	**Expected Outcome**
Accelerated Pace ***Additional*** *$0.01 per month annually ($0.12 more per year)*	20 devices (4 per year)	NPEI to double installation rate to four devices per year.
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	10 Devices (2 per year)	Remain at current installation pace of two devices per year. Install new devices to expand NPEI's Smart Grid network. These devices provide better monitoring capability on the system, which leads to improved restoration times during outages.
Slower Pace ***Decrease*** *of $0.005 per month annually ($0.06 less per year)*	5 Devices (1 per year)	NPEI to cut rate of installation in half to one device per year.

Representative Workbook

Grid modernization

Q Which of the following options do you prefer?



Regional Segmentation	Niagara Falls/Pelham	Lincoln	West Lincoln
Accelerated Pace	43%	38%	38%
Included in Draft Plan	41%	52%	50%
Slower Pace	16%	10%	12%

Bill Impact on Finances	Significant impact	Impact	No Impact
Accelerated Pace	26%	38%	50%
Included in Draft Plan	38%	47%	44%
Slower Pace	36%	15%	6%

LEAP Qualification	LEAP Qualified	Not Qualified (<$52k)	Not Qualified (>$52k)
Accelerated Pace	41%	34%	46%
Included in Draft Plan	32%	49%	45%
Slower Pace	27%	17%	9%

Representative Workbook

Additional Feedback: Grid modernization

Residential

Q Additional Feedback (Optional)

Additional Feedback (n=49) 96% of respondents did not provide additional feedback	**%**
Be proactive/pay now to save later/costs will only increase	29%
Reliability/safety outweighs cost/protect grid/upgrade	16%
Only affected customers should pay	5%
Keeping consumer costs low should be a priority/cost already high	4%
Replace as necessary/most urgent/	2%
Replace within budget/find efficiencies	2%
Cost acceptable	1%
Other	23%
None	17%

Impact of Choices

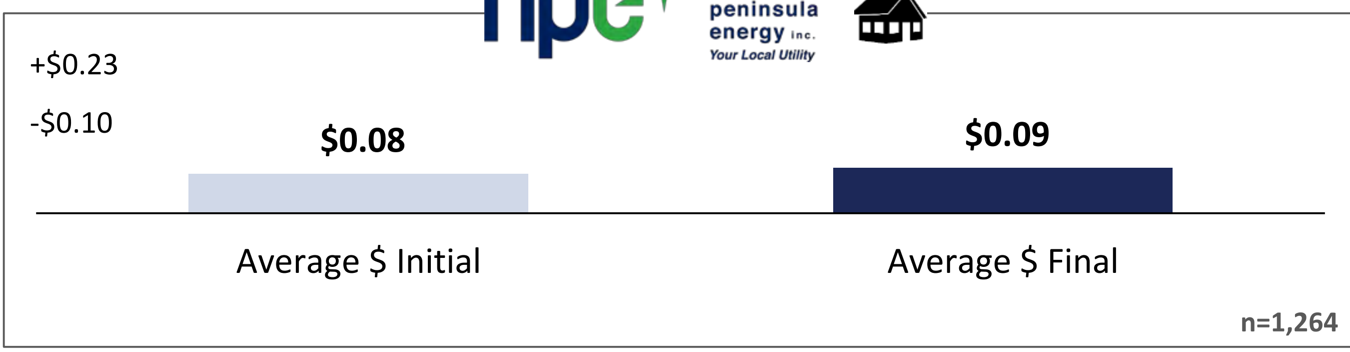
Investment Alternative Summary

Throughout this workbook, you have been asked about **seven key choices** that could impact your rates. Below is a summary of your answers to the questions that could impact your rates.

At the bottom of this page you will find the total bill impact of all the answers.

Having seen the total bill impact, please review your answers and change your responses if you desire; your potential rate impact will be re-calculated. You will have the opportunity to continue adjusting your answers until you feel you've reached the best balance for you.

Q Residential Customer Bill Impact Change and Magnitude of Bill Impact (**MEAN**)



Differences that are statistically significant at 95% are noted by an asterisk (*).

Representative Workbook

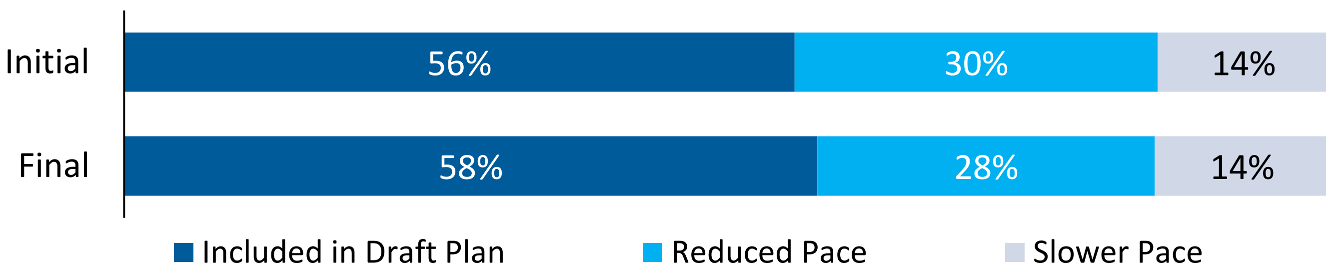
Change in Initial vs. Final Response by Project

Residential

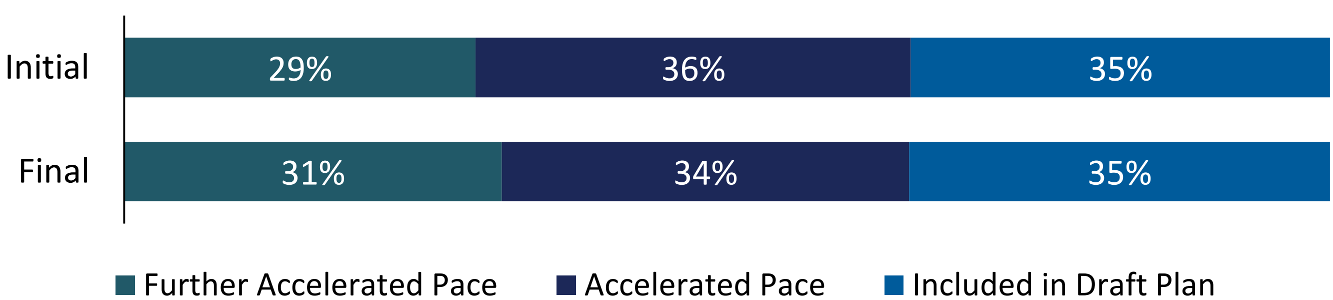
Q Overhead Pole Replacement

Q Overhead Transformer Replacement

Q Converting Outdated Underground Kiosk Transformers



Q Underground Cable Replacement

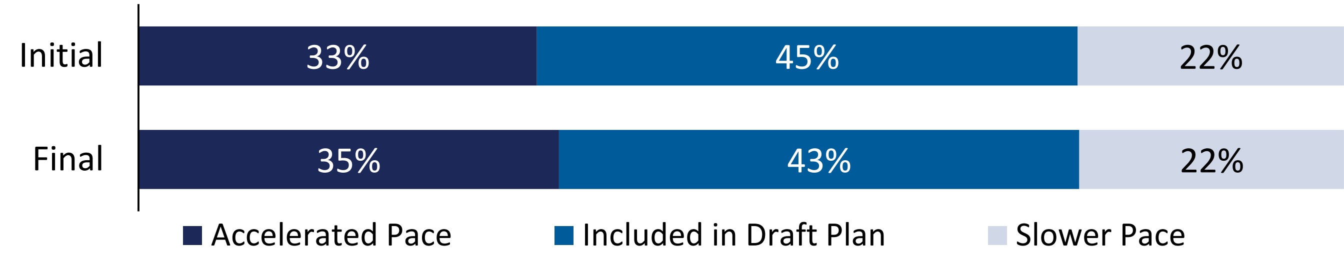


Representative Workbook

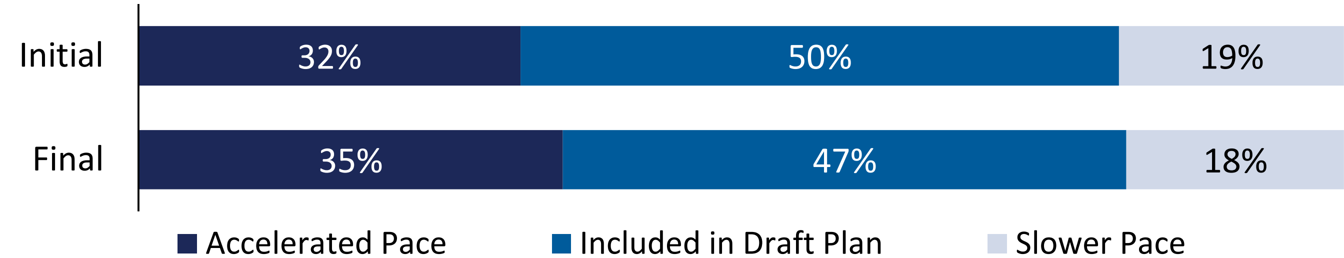
Change in Initial vs. Final Response by Project

Residential

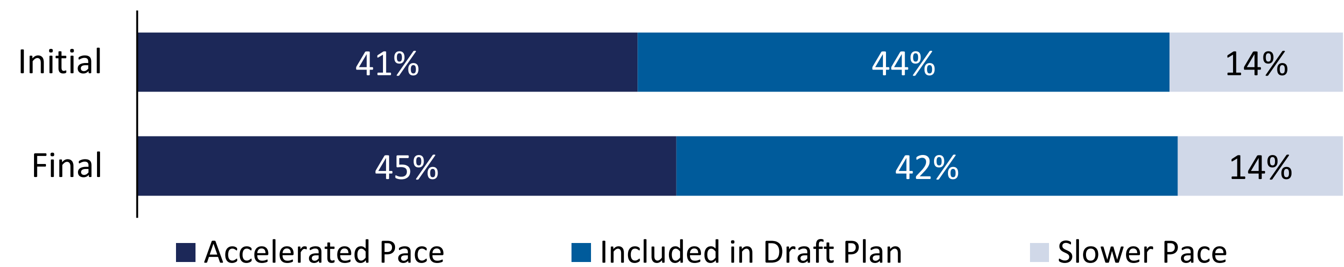
Q Subdivision Underground Rehabilitation



Q Overhead Rebuilds



Q Grid Modernization



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Impact of Choices

Assessing Niagara Peninsula Energy's draft 2021-2025 plan

Again, it is estimated that if NPEI continues with its preliminary plan, the distribution portion of the bill will increase by $2.53 per month in 2021, when the plan is set to come into effect. For the period 2022-2025, the annual bill increase is limited by the OEB to be less than the rate of inflation.

- At the end of the 5-year plan, the typical residential customer would see the distribution portion of their electricity bill increase by $4.29.
- As a result, the distribution charges on the typical residential customer's monthly bill would increase from $33.51 in 2020 to $37.80 by 2025.

Estimated Typical Residential Annual Increase in Monthly Bill (5 year forecast)

	Year	Average Residential Bill	Distribution Portion of Bill	Incremental Rate Change	% Change * (on distribution portion of bill)
Current Rate	2019	$113.32	$33.11		
Budgeted Rate	2020	$115.03	$33.51	$0.40	1.21%
Forecast for next rate period	2021	$116.33	$36.04	$2.53	7.55%
	2022	$118.08	$36.47	$0.43	1.20%
	2023	$119.85	$36.91	$0.44	1.20%
	2024	$121.65	$37.35	$0.44	1.20%
	2025	$123.47	$37.80	$0.45	1.20%
				$4.29	

*** These estimates are preliminary, and are subject to your feedback as the business plan is finalized .**

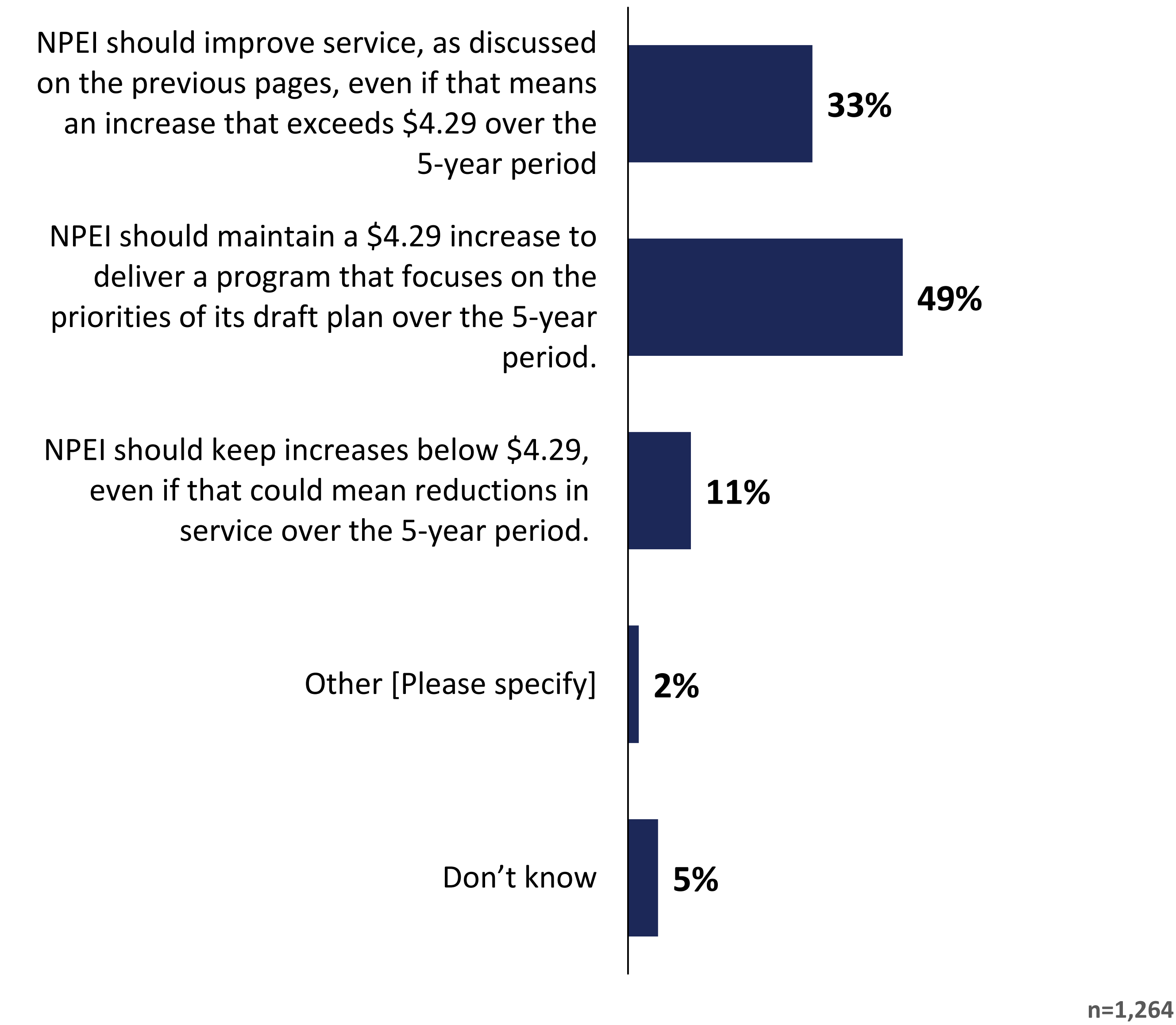
Representative Workbook

Assessing Niagara Peninsula Energy's draft 2021-2025 plan

Residential

Q

Considering what you know about Niagara Peninsula Energy's draft plan – which would see the typical residential customer's distribution portion of their bill increase by $4.29 over the 5-year period – which of the following best represents your point of view?



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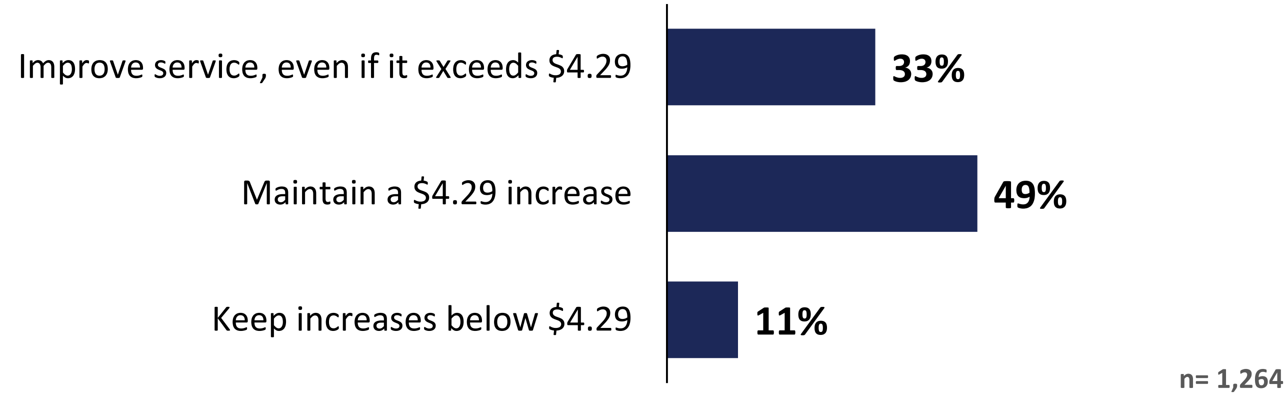
Representative Workbook

Assessing Niagara Peninsula Energy's draft 2021-2025 plan

Q Which of the following best represents your point of view?



n= 1,264

Regional Segmentation	Niagara Falls/Pelham	Lincoln	West Lincoln
Improve service	34%	32%	26%
Maintain increase	46%	56%	56%
Keep increases below	12%	8%	12%

Bill Impact on Finances	Significant impact	Impact	No Impact
Improve service	17%	27%	43%
Maintain increase	36%	55%	50%
Keep increases below	29%	13%	3%

LEAP Qualification	LEAP Qualified	Not Qualified (<$52k)	Not Qualified (>$52k)
Improve service	28%	27%	39%
Maintain increase	41%	52%	48%
Keep increases below	16%	13%	8%

Representative Workbook

Final Comments

Q Thinking about your answer to the previous question, why do you feel that NPEI should take that approach over the 2021-2025 period?

Final Comments (n=370) 71% of respondents did not provide additional feedback	**%**
Proactive approach-Pay now to ensure proper maintenance and prevent higher cost in the future	40%
Increase is reasonable -taking affordability into account	30%
Rates are high enough already/no increase	8%
Prioritize necessary improvements /repair as needed	3%
Unforeseen issues and maintenance should have already been planned in current budget	3%
Look for efficiencies to offset cost	2%
Service reliability should be priority	2%
Need more information	1%
Find alternative funding-Customers should not bear cost increase	1%
Balance approach	1%
Other	7%
None	2%

Q Do you have any final comments regarding NPEI or the customer engagement that you just completed?

Final Comments (n=171) 86% of respondents did not provide additional feedback	**%**
Positive - General NPEI/Survey/ asking for Customer input/informative	35%
Invest now to avoid higher cost in the future/Maintain and repair accordingly	20%
Cost issues/delivery fees/High rates/keep cost low	14%
Alternative energy sources/Turbine/Solar	3%
Negative-General	2%
Transparency-future planning	1%
Other	14%
None	12%

Representative Workbook

Final Thoughts: Workbook Diagnostics

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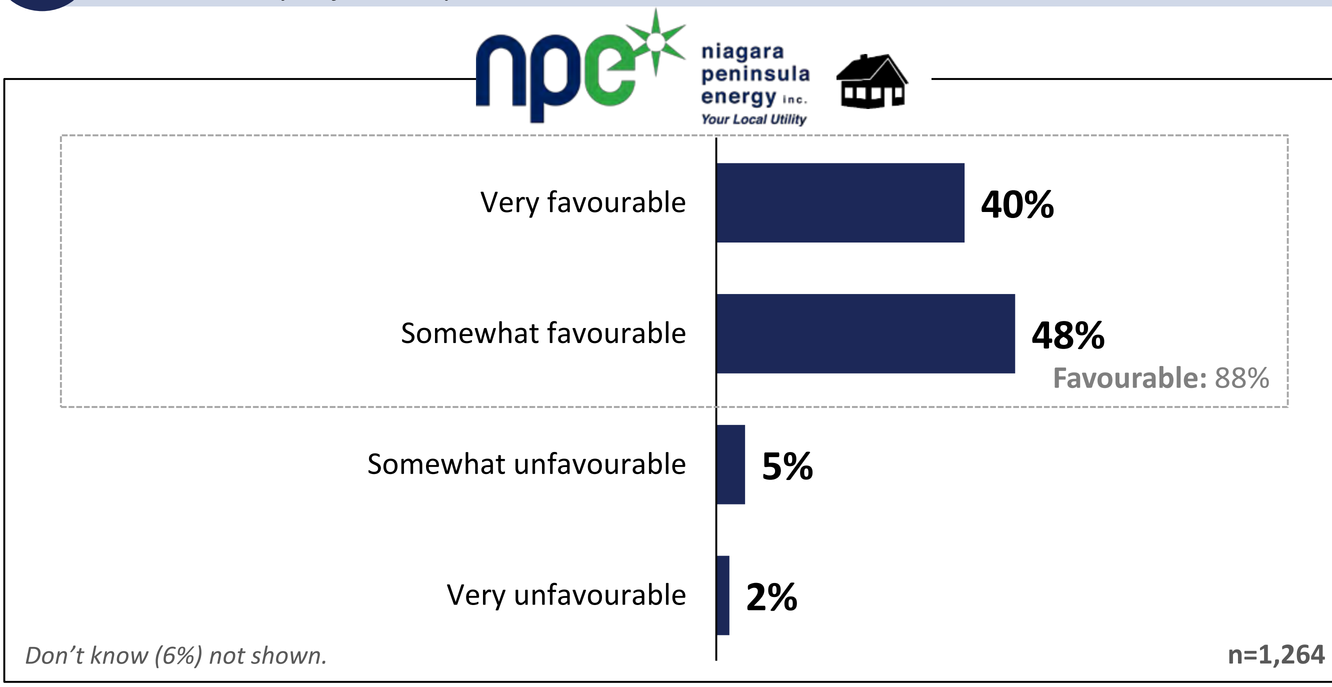
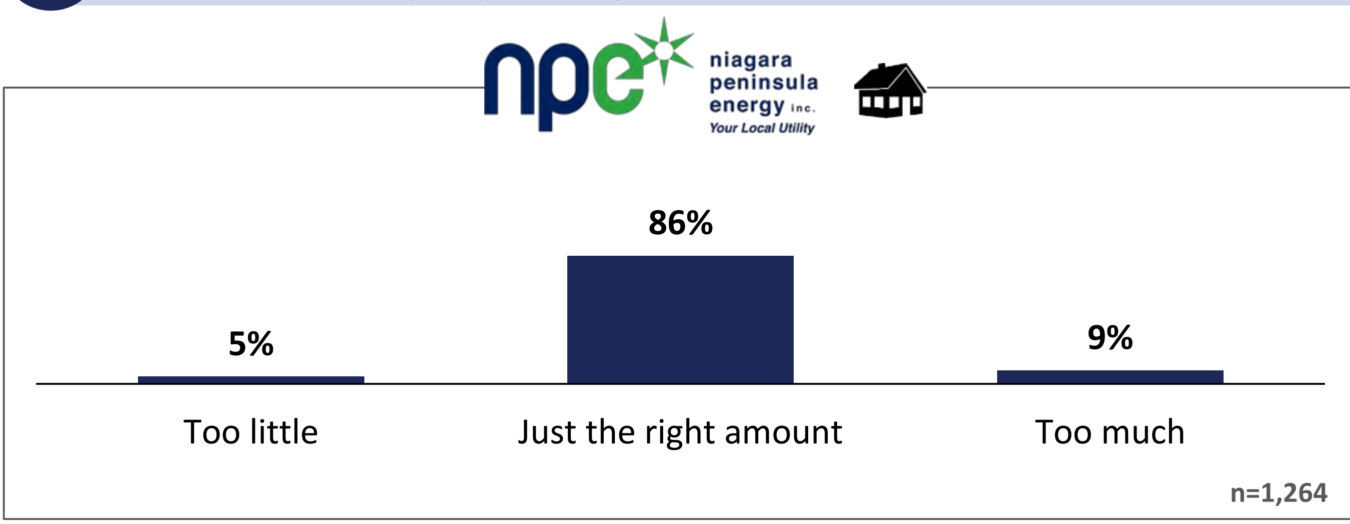
Q **Overall Impression**: Overall, did you have a favourable or unfavourable impression of the consultation you just completed?



Q **Volume of Information:** In this consultation, do you feel that NPEI provided too much information, not enough, or just the right amount?



Representative Workbook

Content Covered and Unanswered Questions

Q Was there any content missing that you would have liked to have seen included in this consultation?

Content Covered (n=1,264)	%
None	90%
Operating costs/Executive-Salaries/bonuses	1%
Alternative energy sources/Turbine/Solar/renewable	1%
Cost/delivery fees/High rates/keep cost low	1%
transparency/breakdown of cost allocation	1%
More information on system reliability aging infrastructure/preventative measures	1%
Billing issues/clearer breakdown/electronic	1%
Other	3%

Q Is there anything that you would still like answered?

Unanswered Questions (n=1,264)	%
None	93%
Cost issues/delivery fees/High rates/keep cost low	2%
Operating costs/Executive-Salaries/bonuses	1%
Power outage information	1%
Other	2%

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Small Business Customers

Online Workbook Results

Representative Workbook

Survey Design & Methodology

INNOVATIVE was engaged by NPEI to gather input on preferences on program timing and balancing outcomes. **Pages 71 to 112** show the actual pages of the workbook that was sent and completed by customers. The only additions are the actual results.

Field Dates & Workbook Delivery

The **Small Business Online Workbook** was sent to all Niagara Peninsula Energy small business customers who have provided the utility with an email address. Customers had an opportunity to complete the workbook between **November 25th and December 27th, 2019**.

Each customer received a unique URL that could be linked back to their annual consumption, region and rate class.

In total, the small business workbook was sent to **1,446** customers via e-blast from INNOVATIVE.

Small Business Online Workbook Completes

A total of **56** (unweighted) Niagara Peninsula Energy small business customers completed the online workbook via a unique URL.

Sample Weighting

The small business online workbook sample has been weighted proportionately by region and consumption quartiles in order to be representative of the broader Niagara Peninsula Energy service territory.

The table below summarizes the unweighted and weighted (in brackets) sample breakdown by region and quartile.

Region	Consumption Quartiles				Total	Distribution
	Low	Medium-Low	Medium-High	High		
Niagara Falls/Pelham	9 (9)	10 (9)	5 (9)	8 (9)	32 (36)	57% (64%)
Lincoln/West Lincoln	5 (5)	5 (5)	7 (5)	7 (5)	24 (20)	43% (36%)
Total	14 (14)	15 (14)	12 (14)	15 (14)	56 (56)	**100%**

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Representative Workbook

Demographic Breakdown

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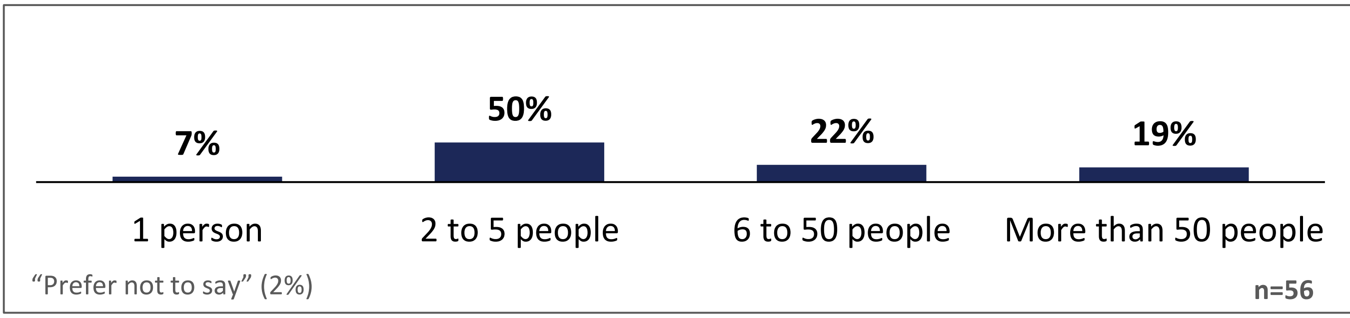
Q Company Size



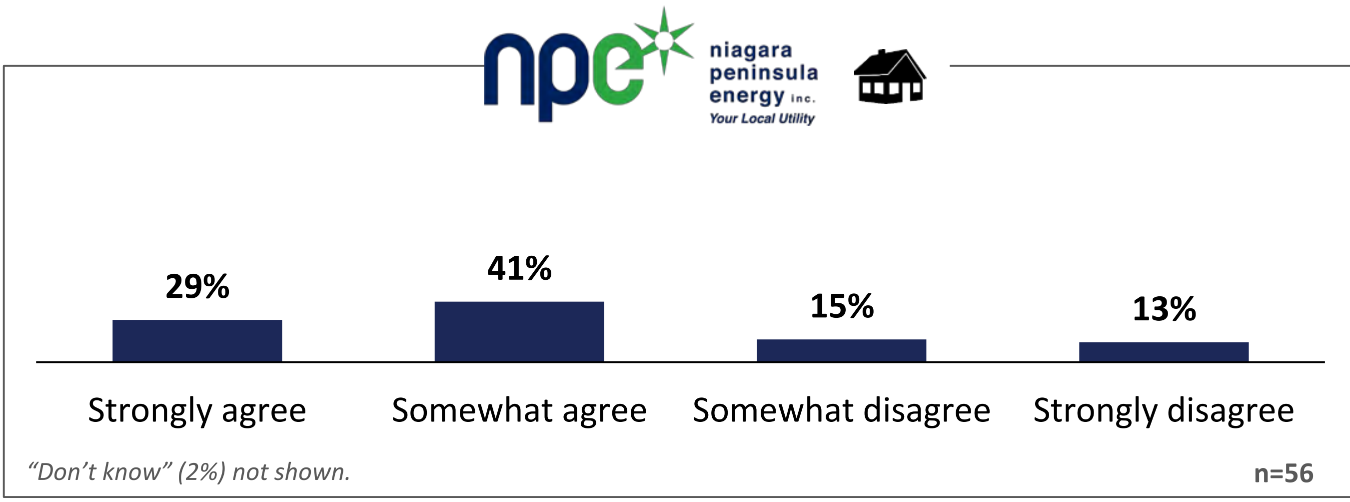
Q Responsibility for Managing or Overseeing Organization's Hydro Bill

Q Sector

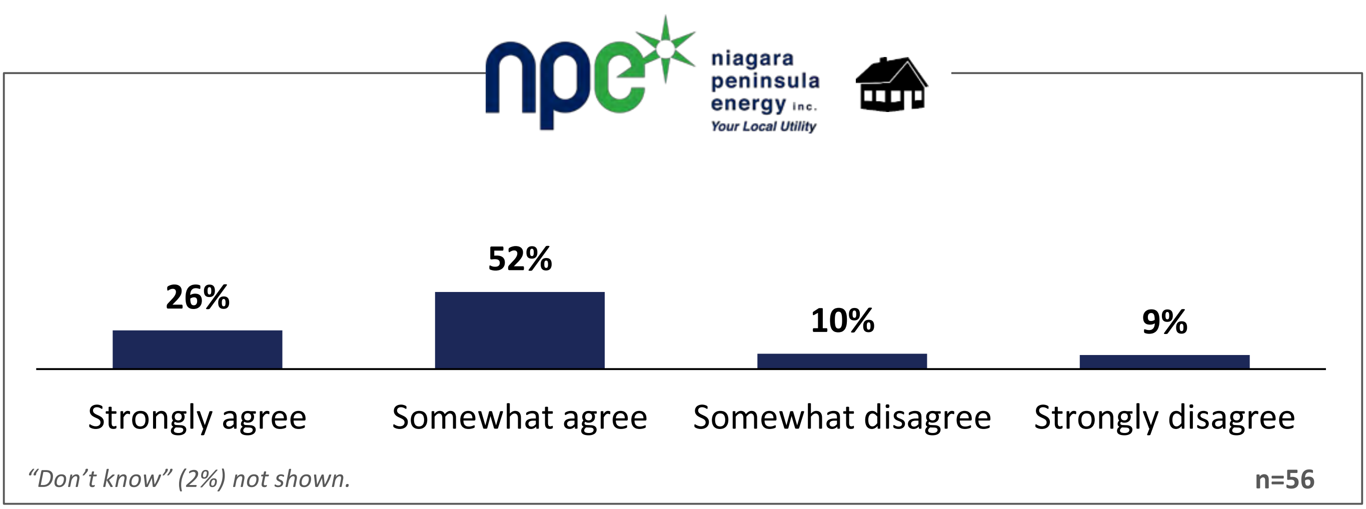
Sector	n-size	Sector	n-size
Commercial	14	Manufacturing/Industrial	2
Retail	12	Hospitality	2
Agriculture/Farm	7	Data Centre	2
Professional Services	5	School	1
Property Management	5	Restaurant/Tavern	1
Not-for-Profit/Church	3	*Prefer not to say*	3

Thinking generally about the electricity system in Ontario, including generation, transmission and local distribution, do you agree or disagree with the following statements?

Q The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.



Q Customers are well served by the electricity system in Ontario.



Representative Workbook

Background Information

About this Consultation

Welcome to Niagara Peninsula Energy's Customer Engagement!

Niagara Peninsula Energy (NPEI) needs your input on choices that will impact the services you receive and the rates that you pay.

- **NPEI** is developing its investment plan for 2021 to 2025. This plan will determine the investments NPEI will make in equipment and infrastructure; the services it provides; and the rates you pay.
- As **NPEI** plans for the future, they want to ensure their business decisions are aligned with customers priorities, preferences, and needs.
- Throughout this survey, information will be provided in an effort to give you more background on which to base your responses.
- While responding to the following questions, remember that there are no wrong answers, and that your individual responses will remain anonymous.
- This customer engagement will take approximately 25-35 minutes to complete, depending on the level of feedback you wish to provide. Your progress will be saved as you move through the workbook, meaning you can leave and return to the customer engagement at any time.

All individual responses will be kept confidential. Innovative Research Group (INNOVATIVE), an independent research company, has been hired NPEI to gather your feedback.

Those who complete the questions that follow will be invited to enter a draw to win one (1) $500 cash prize.

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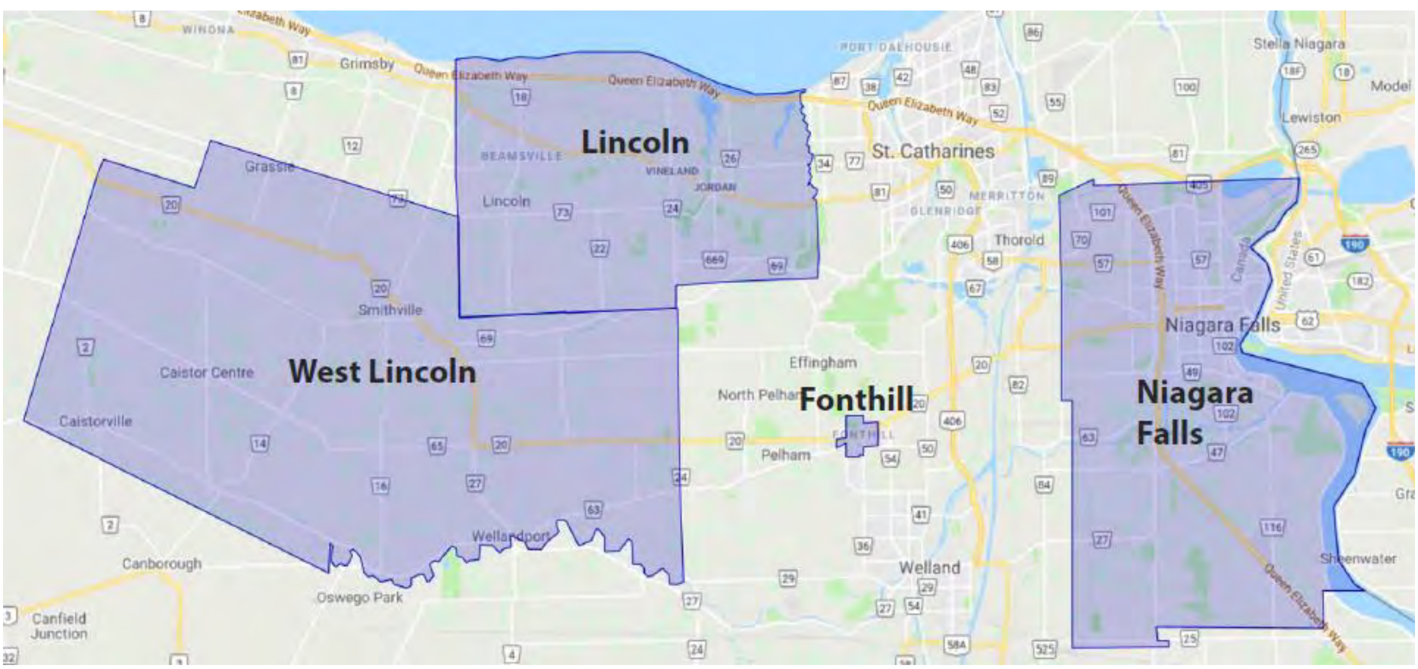
Electricity 101

Who is Niagara Peninsula Energy?

NPEI provides local electricity distribution and related services to residential and business customers in the City of Niagara Falls, Town of Lincoln, Town of Pelham, and Township of West Lincoln.

- NPEI serves an area of approximately 827 square kilometers and 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 local distribution company (LDC) and regulated entity, NPEI applies for, and receives approval from the regulator to charge for its services.



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Background Information

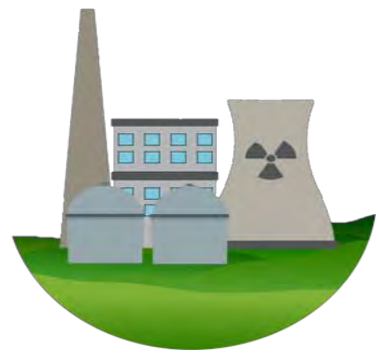
Electricity 101

Niagara Peninsula Energy's Role in Ontario's Electricity System

Ontario's electricity system is owned and operated by public, private, and municipal corporations across the province. It is made up of three key components: **generation**, **transmission** and **distribution**.

Generation

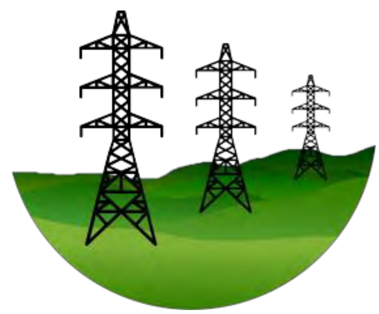
Where electricity comes from



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.

Transmission

How electricity travels across Ontario



Once generated, electricity must be transported to electrical substations 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 kilometres of 'electricity highway', most of which is owned and operated by Hydro One.

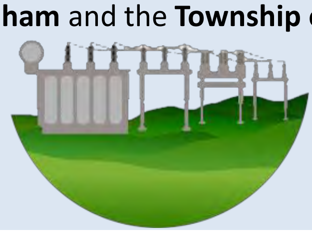
Local Distribution

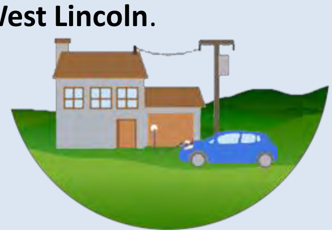
How electricity is delivered to the end-consumer

NPEI is responsible for the last step of the journey: distributing electricity to customers through its distribution system. This local distribution system includes transformer stations that decrease the voltage of the electricity so it can be used safely in your home or business.

There are approximately 1,451 km of overhead power lines and 573 km of underground cable. Through this distribution network, NPEI delivers electricity to approximately 55,600 residential and business customers.

Niagara Peninsula Energy Inc. is jointly owned by the **City of Niagara Falls**, the **Town of Lincoln**, the **Town of Pelham** and the **Township of West Lincoln**.





npe niagara peninsula energy inc.
Your Local Utility

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Familiarity with Ontario's electricity system

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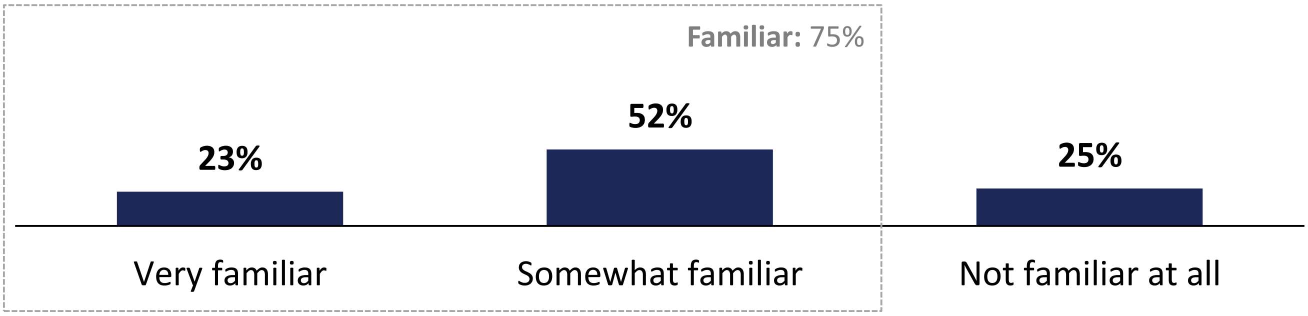
Q Before this survey, how familiar were you with Niagara Peninsula Energy, which operates the electricity distribution system in your community?



n=56

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Electricity 101

How much of my electricity bill goes to Niagara Peninsula Energy?

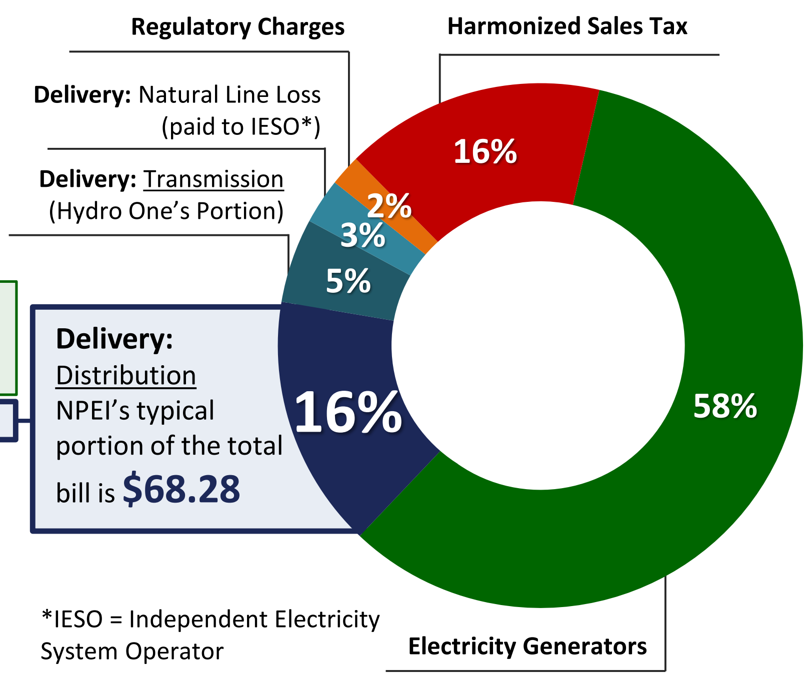
- Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board (OEB), the provincial energy regulator.
- While NPEI is responsible for collecting payment for the entire electricity bill, it retains only the distribution portion of the delivery charge.
- Distribution makes up about **16%** of the typical small business customer's bill.
- The rest of your bill is passed onto provincial transmission companies, power generation companies, the government and regulatory agencies.

NPEI Sample Monthly Bill*
(Based on monthly usage of 2,000 kWh)

Account Number:
000 000 000 000 0000

Meter Number:
00000000

Your Electricity Charges	
Electricity	
Off-Peak @ 10.1 ¢/kWh	129.28
Mid-Peak @ 14.4 ¢/kWh	51.84
On-Peak @ 20.8 ¢/kWh	74.88
Delivery	103.35
Regulatory Charges	8.42
Total Electricity Charges	**$367.77**
HST	47.81
Ontario Electricity Rebate*	(-$116.95)
Total Amount	**$298.63**



*IESO = Independent Electricity System Operator

* As of November 1, 2019. Chart is based on total bill amount after applying the Ontario Electricity Rebate.

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Overall Satisfaction with Niagara Peninsula Energy

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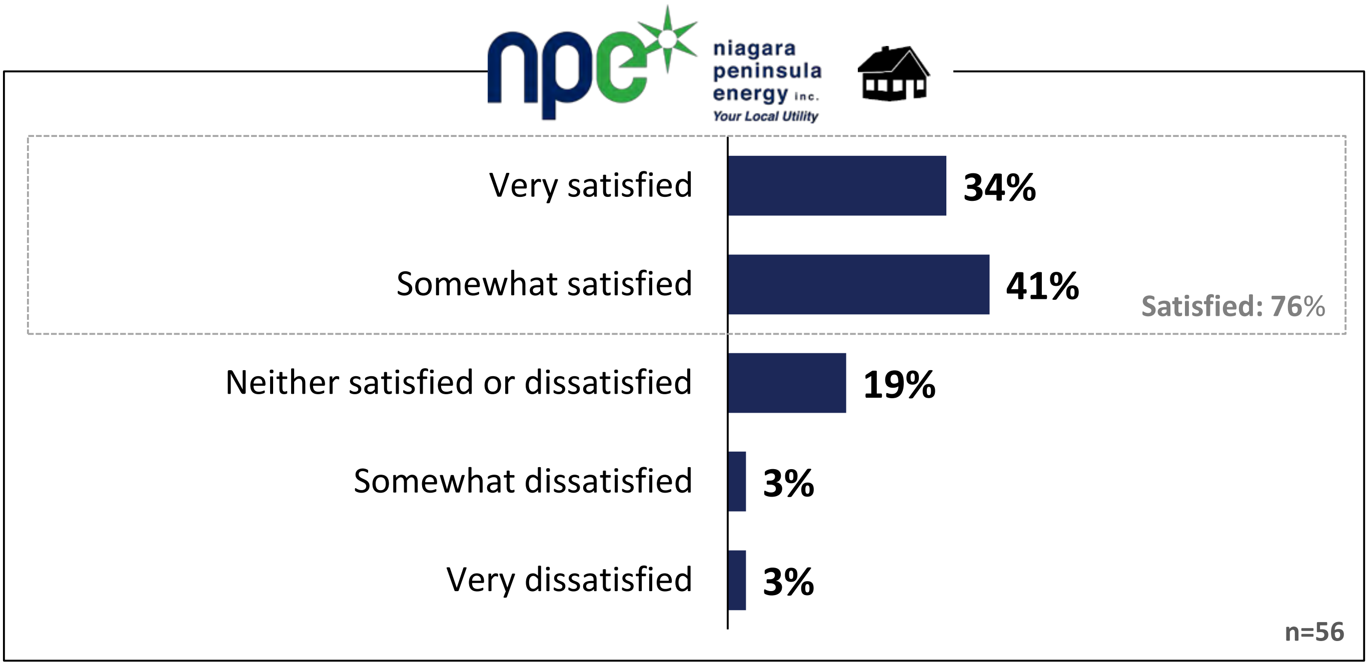
Q Thinking specifically about the services provided to you and your community by Niagara Peninsula Energy, overall, how satisfied or dissatisfied are you with the services that your organization receive?



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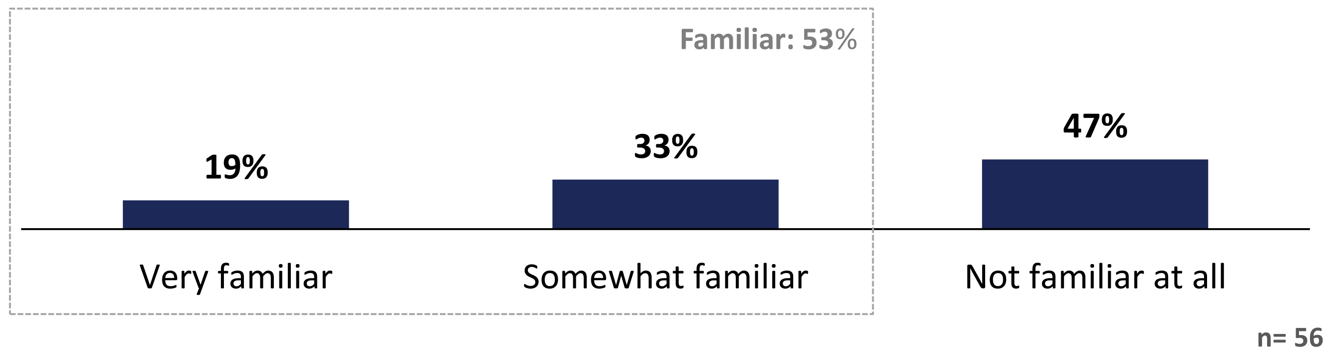
Familiarity with Percentage if Bill Remitted to NPEI

Q Before this survey, how familiar were you with the amount of your organization's electricity bill that went to Niagara Peninsula Energy?



Q Is there anything in particular you would like Niagara Peninsula Energy to do to improve its services to your organization?

Improving Services (n=17) 70% of respondents did not provide additional feedback	**n-size**
Improve billing - clarity/payment terms/methods/website	4
Decrease/eliminate delivery charges	3
Improve reliability/less outages	2
Lower rates/Charge less	1
Do not increase rates/keep rates affordable	1
Provide more info on energy consumption/conservation/renewables	1
Invest in infrastructure/move cables underground	1
None	4

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Niagara Peninsula Energy Background

Building Niagara Peninsula Energy's draft plan

NPEI has put together its draft business plan based on the information and input from various sources, such as:

- **Legal and regulatory** requirements by continuing to meet its obligations.
- **Internal business planning** based on expert analysis and professional judgment to develop construction and operations programs that address safety, business, technical, and operational needs.
- **Customer feedback** collected through both ongoing dialogues and specific engagements, such as this.

There are three key organizations responsible for setting the policy direction of Ontario's electricity system. The decisions made by these organizations impact how utilities operate their businesses and serve their customers.

- **Policy**: The Ontario Ministry of Energy, Northern Development and Mines (MNDM) creates energy policy for the province.
- **Regulation**: The electricity industry in Ontario is regulated by the Ontario Energy Board (OEB). One of the OEB's roles is to review the business and distribution plans of all electricity distributors and approve the rates that they charge customers.
- **Operations and Planning**: The Independent Electricity System Operator (IESO) manages the provincial electricity grid, plans for the province's future energy needs, and develops conservation programs.

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How did customer feedback shape Niagara Peninsula Energy's draft plan?

NPEI is placing more emphasis on incorporating customer feedback into the planning process than ever before.

NPEI engages with its customers both in day-to-day interactions and in a variety of customer engagement activities. These interactions help identify customer needs and preferences, and inform how the utility plans for the future.

This past summer, NPEI engaged with **thousands of residential and business customers** from across its service territory – both in person and through telephone and online surveys.

What did NPEI hear from customers like yourself?

1. The clear majority of NPEI residential and small business customers are satisfied with the current service they receive. When asked how NPEI can improve service, top responses for residential customers were "nothing", followed by "lower or reduce rates".

2. Among competing outcomes, **price**, **reliability**, and **finding internal cost efficiencies** are the top three priorities for both residential and small business customers.

3. While keeping price at a reasonable and affordable level is an important priority, many customers feel that investing in the grid to maintain reliability, is preferable to deferring investments to keep bills low.

Considering this feedback, as well as the information and inputs discussed on the previous page, NPEI has developed a draft plan that is responsive to:

1. Legal requirements by continuing to meet its obligations, including safety and reliability;

2. A transformer station upgrade to accommodate the new Niagara South Hospital and future surrounding growth.

3. Mandatory service connections to accommodate new customers and customer-required upgrades, of which NPEI does not have control over how and when these costs are incurred.

4. Customer feedback by:

    a) Keeping distribution price increases as low as possible;

    b) Maintaining long-term performance for customers experiencing average or better service;

    c) Improving service levels for customers experiencing below average service or who have special reliability needs (e.g. hospitals); and,

    d) Balancing other customer priorities (e.g. customer service) with the need to contain rate increases.

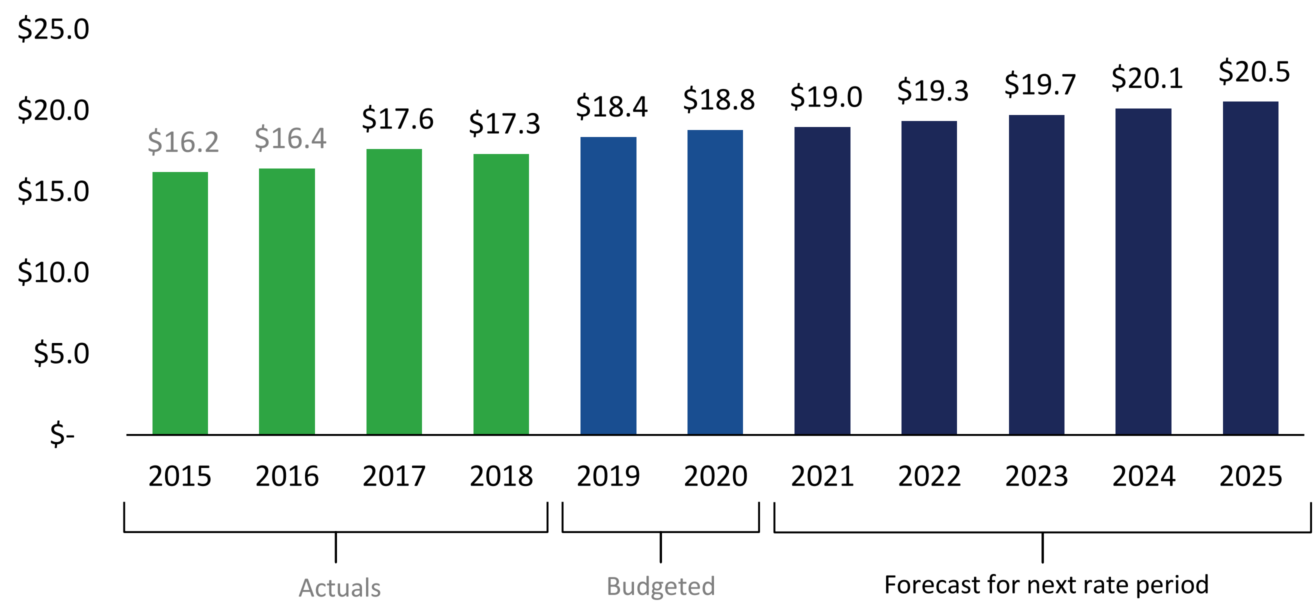
Niagara Peninsula Energy Background

Operating Expenses

In this section, we want to focus on operating expenses and how NPEI compares to its peers.

NPEI's operating budget covers recurring expenses, such as the maintenance of poles, wires, transformers, fleet and buildings as well as proactive maintenance programs such as tree trimming, and payroll for employees. Meter reading, postage, cyber security and hardware/software maintenance expenses are billing and customer service-related expenses. The proposed 5-year plan, between 2021 and 2025, would see NPEI spend an estimated total of $98.7 million on operations.

NPEI's Current and Forecasted Operating Expenses, per Year (Millions)*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

NPEI's **operating costs** are benchmarked by the OEB against other utilities in Ontario. In the last year of publicly available data collected by the OEB, NPEI's operating costs per customer was **$311.67**, which is slightly more than some, while less than both Hydro One and Canadian Niagara Power.

2018 Operating & Maintenance and Administration (OM&A) Per Customer ($)

The diverse geographical nature of NPEI's service territory, which is a mix of urban and rural communities is a large consideration/driver of these OM&A costs. In some parts of the service territory, there may be less than 30 customers per kilometer of line. Despite low density, these lines still require the same level of ongoing maintenance, including tree trimming and other expenses that contribute to operating the system; thereby resulting in a higher cost per customer.

Niagara Peninsula Energy Background

Operating Expenses

Recall, this customer feedback portal does not ask questions that expect you to be an electricity expert.

The OEB runs an open and transparent review process where experts from the OEB and intervenor groups review and challenge NPEI's analyses and assessments. You are welcome to participate in the OEB process if you are interested in those issues. Details can be found at oeb.ca/participate.

This customer engagement however, is focused on capital investments.

Detailed discussion of NPEI's operating budget is left to experts from the OEB and intervenors in the formal rate application review; this workbook focuses on collecting your view on competing trade-offs in capital investments.

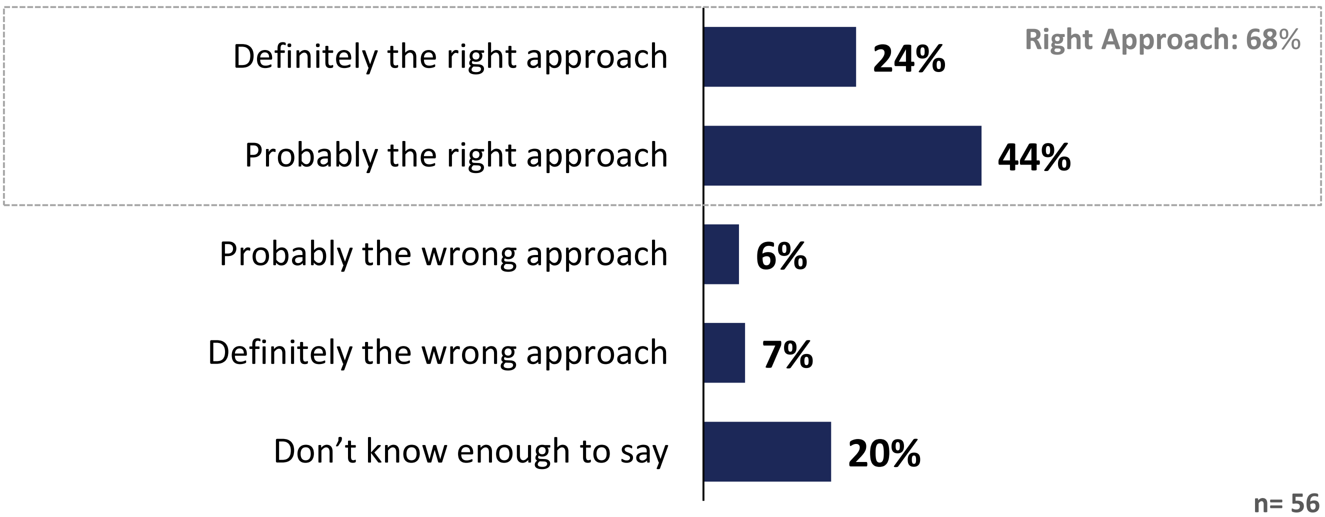
Representative Workbook

Approach to Operating Expenses

Small Business

Q

Does leaving the detailed discussion about Niagara Peninsula Energy's operating budget to experts from the OEB and intervenors seem like the right approach or wrong approach to you?



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Background Information

Niagara Peninsula Energy Background

Capital Investments

NPEI's **capital budget** covers items that, once purchased, have lasting benefits over many years. Year-over-year, regardless of external drivers, NPEI will need to make investments in the core distribution system, including poles, wires, cables and transformers.

Based on initial customer input and the approach outlined previously, NPEI believes the capital expenditure required to address system renewal, maintain system reliability and safety, and invest in other infrastructure priorities between 2021 and 2025 is estimated to be **$70.3 million**.

NPEI classifies the costs of four types of capital investment between 2021 and 2025. Each of these four investment categories helps NPEI pace and prioritize projects.

2021-2025 Forecasted Capital Investments

System Renewal ($38.2 million)

These projects are a mix of planned end-of-life replacements and emergency replacements.

Projects Include: Replacement of existing overhead wires, poles, and pole mounted transformers, underground cables and transformers and transformer station upgrades.

System Access ($17.1 million)

"Must do" investments that respond to customer requests for new connections or new infrastructure development.

Projects Include: NPEI's share of new subdivisions, new upgraded commercial and industrial services, and relocating assets based on road infrastructure needs.

General Plant ($8.4 million)

These are investments needed to support the distribution system, such as tools, vehicles, buildings, and computers.

Projects Include: Financial and customer IT systems, enhanced cyber security investments, facility renovations, backup generation, and vehicle replacements.

System Service ($6.6 million)

These investments consist of projects that address capacity constraints, improve system reliability and customer service.

Projects Include: Installation of automated switches and system expansion to supply new development.

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Niagara Peninsula Energy Background

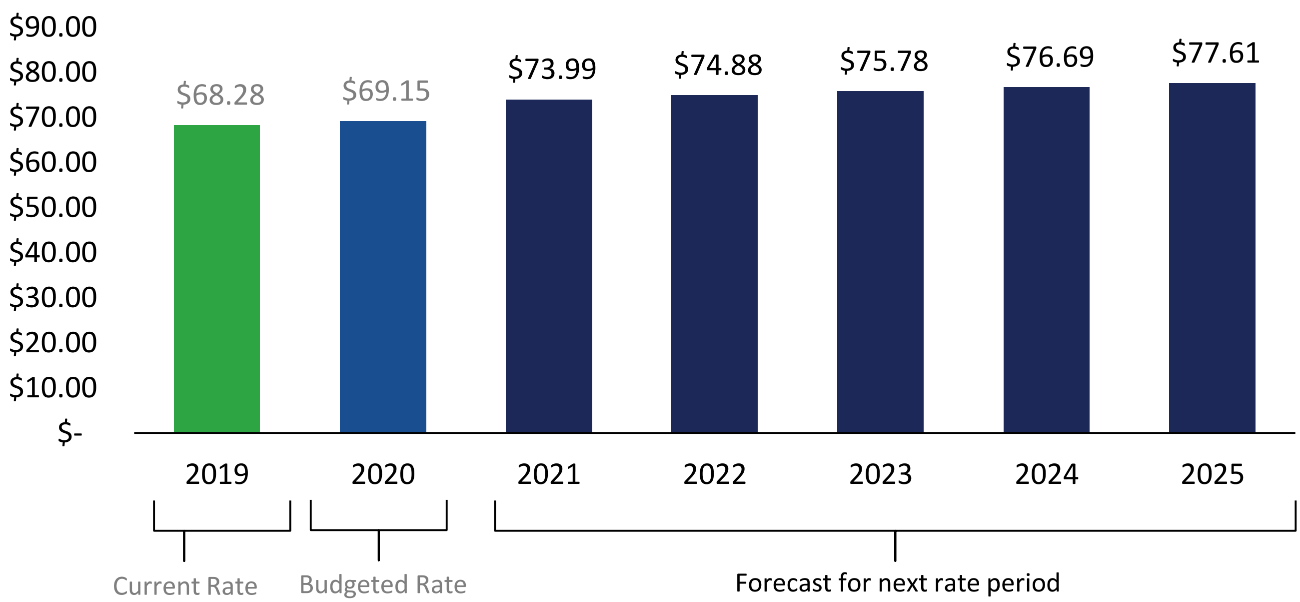
How much will this draft plan cost me?

Remember, the current typical NPEI small business customer's electricity bill is about $298 per month, of which $68.28 goes to NPEI.

It is estimated that if NPEI continues with its preliminary plan, the distribution portion of the bill will increase by $4.84 per month in 2021, when the plan is set to come into effect. For the period 2022-2025, the annual bill increase is limited by the OEB to be less than the rate of inflation.

- At the end of the 5-year plan, the typical small business customer would see the distribution portion of their electricity bill increase by $8.46.
- As a result, the distribution charges on the typical small business customer's monthly bill would increase from $69.15 in 2020 to $77.61 by 2025.

Estimated Small Business Monthly Distribution Charge, per Year*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

NPEI is looking for your input on its preliminary plan to ensure it is making the spending decisions that matter to you, the customer.

The following sections of this workbook will explore some of the choices Niagara Peninsula Energy needs to make to help finalize its preliminary plan.

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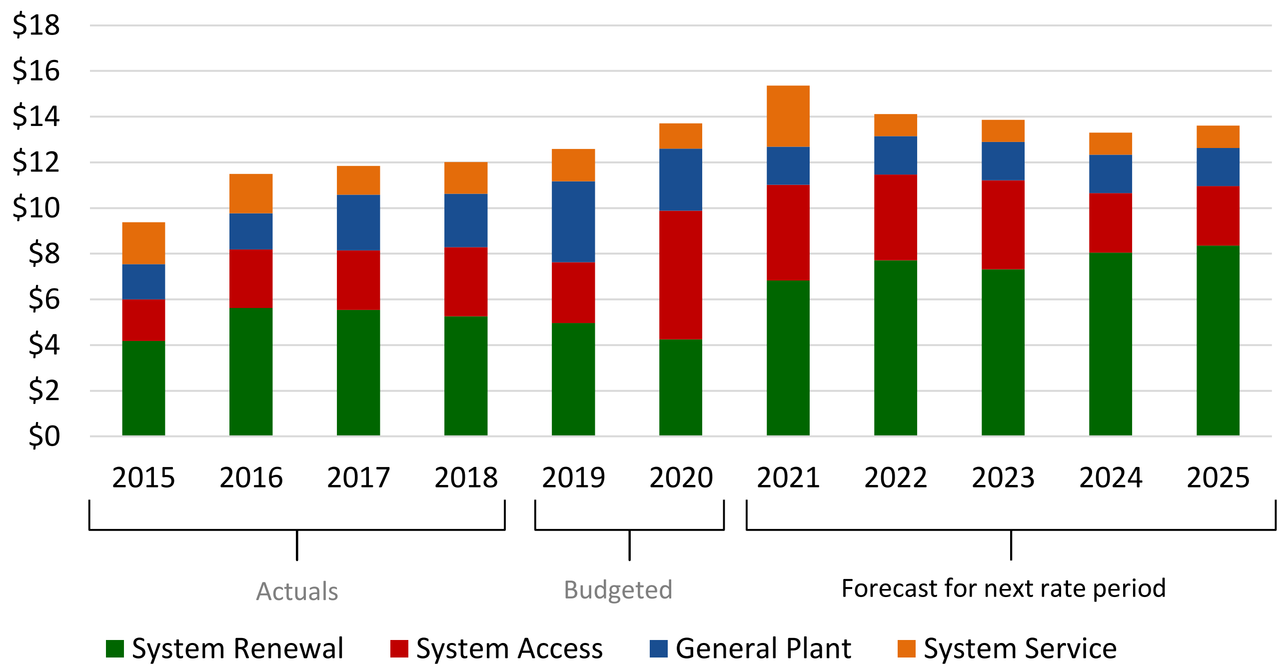
Niagara Peninsula Energy Background

Pacing Capital Investments

The overall amount NPEI invests in capital projects remains generally the same year over year, but what does change is where these investments are made. In some years, when unplanned or unforeseen investments are needed, NPEI will re-allocate funds to make room for these projects within the approved budget. This helps limit the overall amount that the distribution charges fluctuate year-over-year.

The chart below outlines NPEI's spending in past years, and proposed spending for the 5-year period 2021 to 2025.

2015 – 2025 Historical and Forecasted Capital Investments*



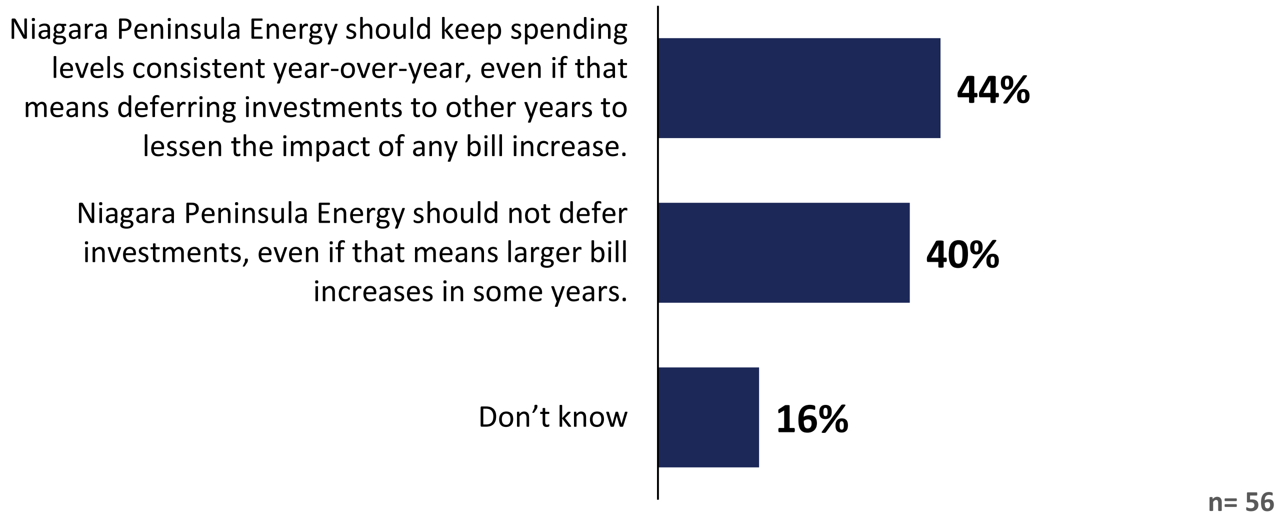
* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

System Access expenditures are budgeted to increase to $5.6M in 2020 to accommodate a number of large commercial customer growth projects as well as municipal road work.

Representative Workbook

Approach to Pacing Investments

Q Which of the following statements best represents your point of view regarding Niagara Peninsula Energy's approach to pacing investments?



Q Additional Feedback (Optional)

Additional Feedback (n=8) 86% of respondents did not provide additional feedback	**n-size**
Deferring only increases future prices/invest now in technology and equipment	2
No increase-keep cost low too high already	2
Case by case basis/Prioritize spending on what is needed most	1
Reliability of services is paramount	1
None	3

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Mandatory Investments

Federal, provincial, and municipal governments as well as regulators set requirements and standards that NPEI must satisfy. Mandatory investments can be broken down into three categories:

- **Connecting customers**: This includes connecting customers to the grid when a new home or building is constructed or modified.
- **Moving equipment**: This includes moving equipment like poles and cables for road widening.
- **Mandated obligations**: This includes installing and maintaining customer meters and transferring electricity from the provincial transmission system.

These mandatory investments mean that about **one-in-four dollars (23%)** of your distribution rates over the past five years have not been available for other non-mandatory investments. Looking forward to the 2021-2025 period, NPEI forecasts a similar level of mandatory investments, driven largely by:

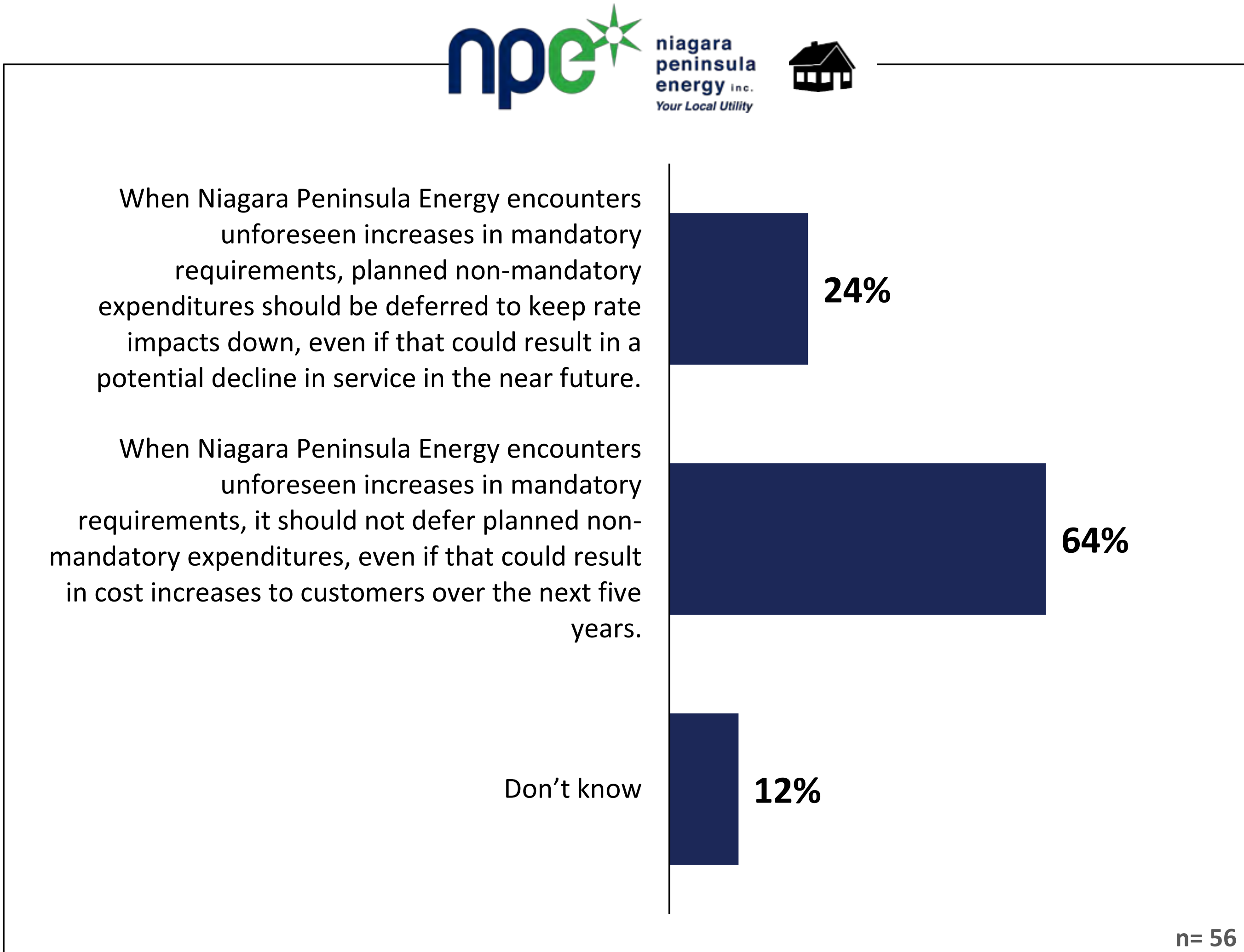
- **Preparing to connect the new Niagara South hospital;**
- **Work to accommodate the 2021 Canada Summer Games in the Niagara Region, and;**
- **Work to accommodate growth and future electricity capacity needs.**

Representative Workbook

Approach to Mandatory Investments

Small Business

Q Which of the following statements best represents your point of view regarding Niagara Peninsula Energy's approach to mandatory and non-mandatory spending?



Q Additional Feedback (Optional)

Additional Feedback (n=8) 86% of respondents did not provide additional feedback	**n-size**
Increase within reason when expenditures are necessary/Balance over 5 years	3
Case by Case basis/New developers/builders/Company/2021 Canada Games/Government- should fund costs	2
Unforeseen increases should not be encountered/should already be in budget	2
None	1

Making Choices (1 of 7)

Overhead Pole Replacement

A recent asset health condition assessment shows that **575 or approximately 3%** of the poles in NPEI's distribution system are in *poor* or *very poor* condition. Each year, new poles enter this condition, and NPEI takes an approach that proactively replaces poles as to not create a large backlog. As a general rule, pole failure only causes an outage when something happens outside of the utility's control, most frequently due to trees knocking them down or a car accident.

On average, since 2014, NPEI has replaced approximately 88 poles per year. This pace has effectively maintained reliability over this period.

NPEI is proposing to replace most of these 575 poles in poor and very poor condition over the course of the next five years, however, there is an opportunity to replace these poles more quickly or slowly. NPEI must continue to invest in overhead pole replacement, therefore, this is a matter of whether customers would rather pay more during the upcoming period, or push some level of investment beyond the next five years.

Option	Poles Replaced	Expected Outcome
Accelerated Pace ***Additional*** *$0.03 per month annually ($0.36 more per year)*	1,000 by 2025 (200 per year)	Address the very poor and some of the poor condition poles identified in the Asset Condition Assessment.
Included in Draft Plan *Within proposed average 2.4% increase over 5-years*	500 by 2025 (100 per year)	Address most of the very poor condition poles identified in the Asset Condition Assessment and annual pole inspections by 2025.
Slower Pace ***Decrease*** *of $0.02 per month annually ($0.24 less per year)*	250 by 2025 (50 per year)	Address only the poles in need of immediate replacement, as identified in the annual pole inspection report.

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Overhead Pole Replacement

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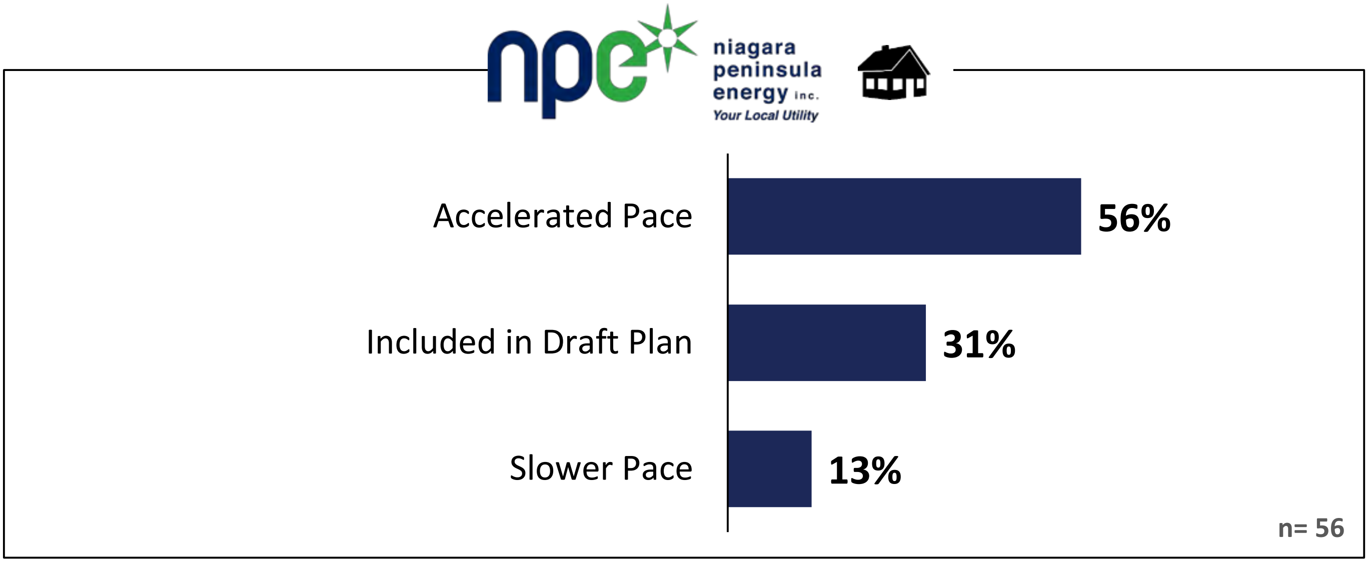
Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

Additional Feedback (n=6) 86% of respondents did not provide additional feedback	**n-size**
Be proactive/pay now to save later/costs will only increase	1
Bury lines/better to replace with underground lines	1
Reliability/safety outweighs cost	1
Investigate/Invest in new pole technology	1
Information misleading/skeptical about figures/inspection criteria	1
Coordinate with other services/find other revenue streams	1

Making Choices (2 of 7)

Overhead transformer replacement

Transformers are a critical piece of distribution equipment that reduce voltage from the higher levels that are more efficient to move electricity long distances to lower levels that are safer to connect to homes and businesses. They are typically either located on the ground, in underground vaults, or attached to distribution poles

A recent asset health condition assessment shows that **1,251 or approximately 21%** of the overhead transformers in NPEI's distribution system are in poor or very poor condition.

Since 2014, overhead transformer failure has directly resulted in approximately 15 outages per year. That said, in most cases, when an overhead transformer fails, it only impacts a small amount of customers and the equipment can be replaced within 2-3 hours depending on the circumstances.

However, when these outages do occur, it can take NPEI crews an extended period of time to replace the cable and restore power to affected households and businesses.

NPEI is proposing a new program to proactively replace **250 of the 677 or 37%** of the overhead transformers identified as very poor condition before they fail over the course of the next five years.

As with distribution poles, NPEI will proactively invest in overhead transformer replacement, therefore, this is a matter of whether customers would rather pay more during the upcoming period, or push some level of investment beyond the next five years.

Option	Transformers Replaced	Expected Outcome
Accelerated Pace ***Additional*** *$0.01 per month annually ($0.12 more per year)*	375 by 2025 (75 per year)	Address some of the polemount transformers identified as very poor in the Asset Condition Assessment report.
Included in Draft Plan *Within proposed average 2.4% increase over 5-years*	250 by 2025 (50 per year)	Address some of the polemount transformers identified as very poor in the Asset Condition Assessment report.
Slower Pace ***Decrease*** *of $0.01 per month annually ($0.12 less per year)*	125 by 2025 (25 per year)	Address only the worst of the polemount transformers identified as very poor in the Asset Condition Assessment report.

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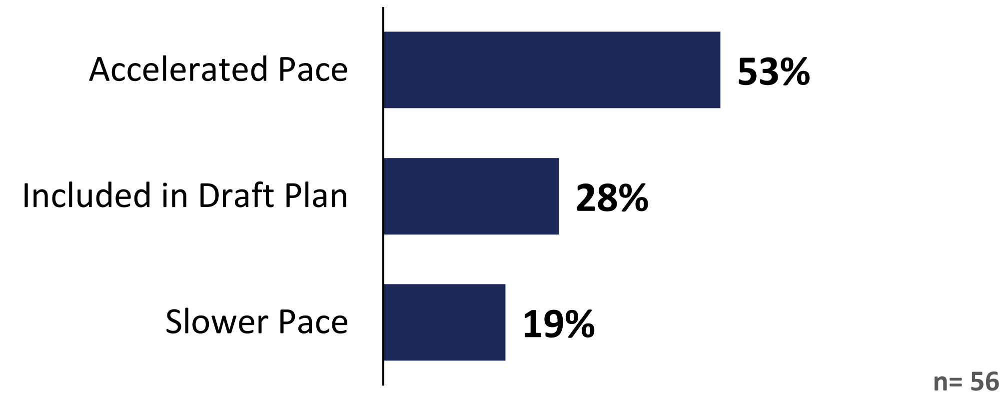
Overhead transformer replacement

Small Business

Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

Additional Feedback (n=7) 88% of respondents did not provide additional feedback	**n-size**
Replace within budget/find efficiencies/no increase to the consumer	3
Reliability/safety outweighs cost	1
Data/figures questionable	1
Cost acceptable/negligible	1
Be proactive/pay now to save later/costs will only increase	1

Making Choices (3 of 7)

Converting Outdated Underground Kiosk Transformers

NPEI's system features a type of underground transformer that was popular in the 1940s to 1970s which no longer meets construction and safety standards. While this equipment still functions, it is becoming increasingly difficult to safely and effectively maintain. When this equipment does fail, it can result in lengthy outages due to the limited accessibility due to the original method of construction.

On average, since 2014, NPEI has converted approximately 9 kiosk transformers per year. Between 2018 and 2019, the pace of this program has been pushed off, and today, there remains 75 transformers in need of replacement.

NPEI is proposing to convert all of this equipment within the next seven years, with 55 being converted in the next five year period. That said, there is an opportunity to convert these kiosk transformers more slowly.

Option	Transformers Installed	Expected Outcome
Included in Draft Plan *Within proposed average 2.4% increase over 5-years*	55 by 2025 (11 per year)	Work towards eliminating all old installations over the next 7 years.
Reduced Pace ***Decrease*** *of $0.02 per month annually ($0.24 less per year)*	25 by 2025 (5 per year)	Work towards eliminating all old installations over the next 15 years.
Slower Pace ***Decrease*** *of $0.04 per month annually ($0.48 less per year)*	10 by 2025 (2 per year)	Work towards eliminating all old installations over the next 35 years.

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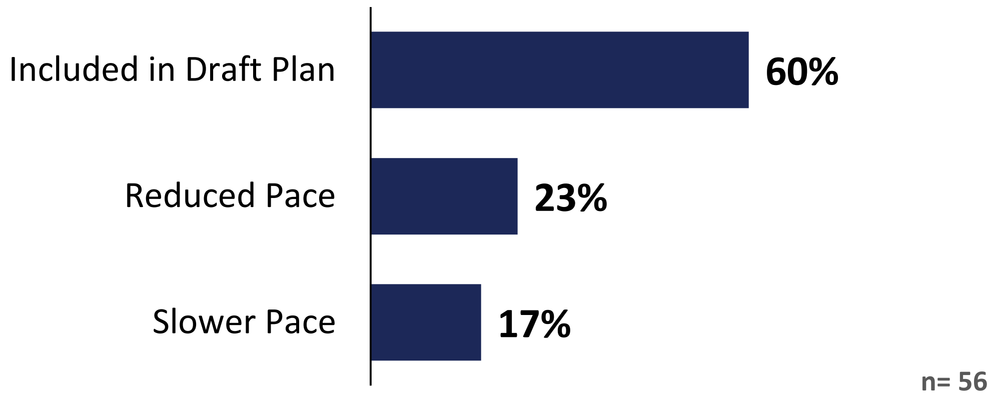
Converting Outdated Underground Kiosk Transformers

Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

Additional Feedback (n=5) 92% of respondents did not provide additional feedback	**n-size**
Replace as necessary/most urgent/outdated first/run to fail	2
Reliability/safety outweighs cost	1
Replace within budget/find efficiencies/no increase to the consumer	1
None	1

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Making Choices (4 of 7)

Underground cable replacement

Many neighbourhoods across NPEI's service territory are serviced by underground cables. Historically, NPEI has taken a "run-to-failure" approach with this equipment; that is, a cable will be replaced only once it has failed. The age of this equipment is now becoming a concern, with approximately 78 km or 18% of underground cable operating beyond its estimated useful life of 35 years.

Since 2014, underground cable failure has directly resulted in approximately ten outages per year, and when these outages do occur, it can take NPEI crews an extended period to replace the cable and restore power to affected households and businesses.

Between 2021 and 2025, NPEI is proposing a new program that will replace cable that has been identified as past end of life when completing other associated work. NPEI believes that this could help reduce the number and length of outages caused by underground cable failure, as well as to start getting ahead of the ongoing age issue. That said, there is an opportunity to take a more proactive approach to addressing some of the older cable in the system.

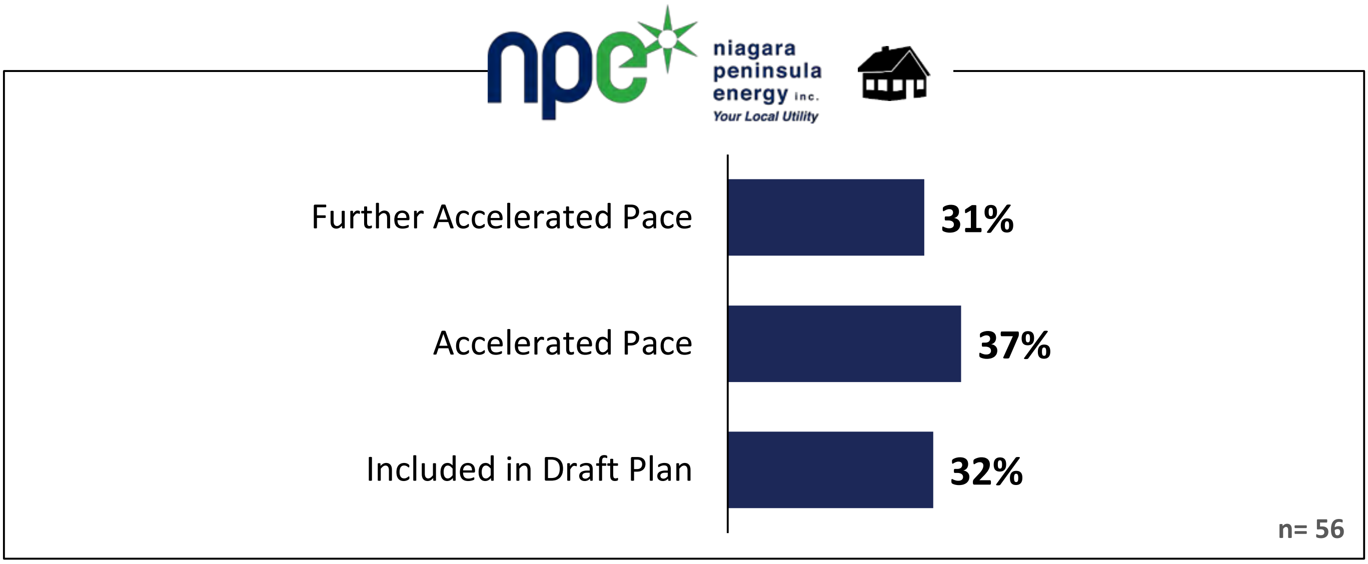
Option	Km of cable installed	Expected Outcome
Further Accelerated Pace ***Additional*** *$0.35 per month annually ($4.20 more per year)*	24 km by 2025 (4.8 km per year)	Proactively replace more of the cables identified as past end of life in the Asset Condition Assessment Report.
Accelerated Pace ***Additional*** *$0.07 per month annually ($0.84 more per year)*	12 km by 2025 (2.4 km per year)	Proactively replace some of the cables identified as past end of life in the Asset Condition Assessment Report.
Included in Draft Plan *Within proposed average 2.4% increase over 5-years*	2 km by 2025 (0.4 km per year)	Replace cables past end of life as other work is being completed on associated switchgear or riser poles.

Representative Workbook

Underground cable replacement

Small Business

Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

Additional Feedback (n=4) 93% of respondents did not provide additional feedback	**n-size**
Replace as necessary/most urgent first/if it isn't broke	2
Reliability/safety outweighs cost	1
Replace within budget/no increase to consumer/cash grab	1

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Making Choices (5 of 7)

Subdivision underground rehabilitation

71 of the subdivisions in NPEI's service territory were constructed with **direct buried cable** which refers to a type of construction where cables are laid directly in underground trenches without a protective barrier.

While this was typical construction at the time, 40 of these subdivisions were built 40 or more years ago, and the cables are now approaching the end of their recommended life.

In this upcoming plan, NPEI is proposing a new program to start preparing to upgrade the service in the subdivisions with the most pressing needs.

In order to keep costs down, NPEI is proposing to start rehabilitation of the underground "system" by installing ducts that will eventually carry underground cables over the next five years. The cables would be installed as needed (upon failure) or once all of the old subdivisions have had the duct installed.

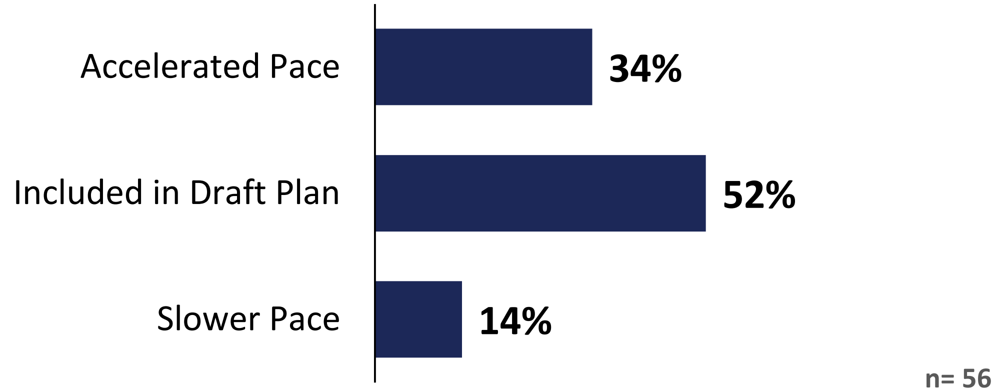
Completing this work in two phases will not only save costs now, but also help ensure that NPEI will be able to rehabilitate the most subdivisions in the shortest time.

Between 2021 and 2025, NPEI is proposing a new program that will proactively install ducts in approximately 10 subdivisions. Which subdivisions receive investment first will predominantly be based on age. That said, there is an opportunity to either accelerate or slow down the pace of this new program.

Option	Km of vault installed	Expected Outcome
Accelerated Pace ***Additional*** *$0.03 per month annually ($0.36 more per year)*	30 km by 2025 (6 km per year)	Install 6 km of ducts or approximately four subdivisions per year.
Included in Draft Plan *Within proposed average 2.4% increase over 5-years*	15 km by 2025 (3 km per year)	Install 3 km of ducts or approximately two subdivisions per year.
Slower Pace ***Decrease*** *of $0.01 per month annually ($0.12 less per year)*	7.5 km by 2025 (1.5 km per year)	Install 1.5 km of ducts or approximately one subdivision per year.

Representative Workbook
Subdivision underground rehabilitation

Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

Additional Feedback (n=2) 96% of respondents did not provide additional feedback	**n-size**
Reliability/safety outweighs cost	1
Replace within budget/no increase to consumer	1

Making Choices (6 of 7)

Overhead rebuilds

Beyond replacing overhead poles, NPEI has a program that rebuilds the overhead system for entire streets and neighbourhoods. This includes poles, wires, and all other equipment that goes into operating the overhead system.

A recent asset health condition assessment identified a total of **60 areas** within NPEI's service territory that require complete overhead rebuilds**.** Most of this equipment is either beyond its recommended age or deteriorated due to weather and other factors. This infrastructure is in addition to the poles identified in the earlier section.

This program is intended to contribute to the "betterment" of the overhead system by;

- Improving system performance by installing animal guards and higher capacity transformers to reduce the likelihood of outages, and;
- Improving system aesthetics with new and taller poles.

On average, each of the projects would replace approximately 30-40 poles, depending on the population density of the area being worked on. NPEI's current approach would rebuild **40 out of 60 areas** in the 2021 to 2025 period.

NPEI must continue to invest in overhead rebuilds, therefore, this is a matter of whether customers would rather pay more during the upcoming period or push some level of investment beyond the next five years.

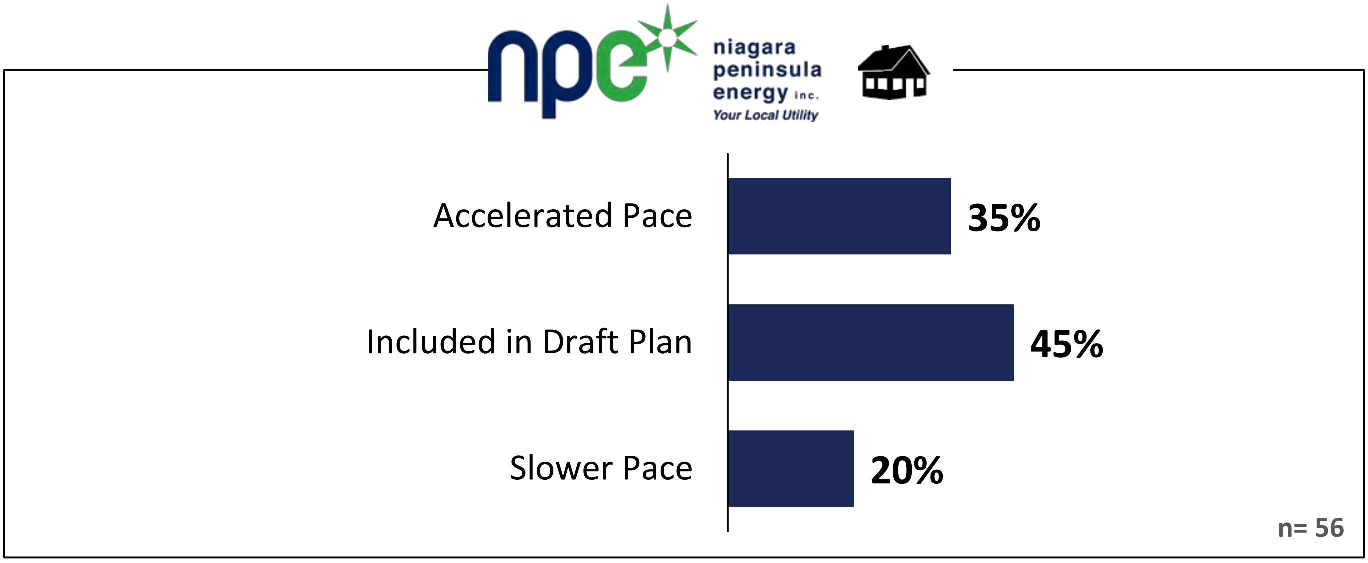
Option	Overhead rebuilds	Expected Outcome
Accelerated Pace ***Additional*** *$0.04 per month annually ($0.48 more per year)*	61 km by 2025 (12.2 km per year)	Rebuild 12.2 km per year or approximately 10 projects per year
Included in Draft Plan *Within proposed average 2.4% increase over 5-years*	48.5 km by 2025 (9.7 km per year)	Rebuild areas with assets that have been identified as very poor in Asset Condition Assessment. Rebuild 9.7 km per year or approximately 8 projects per year
Slower Pace ***Decrease*** *of $0.04 per month annually ($0.48 less per year)*	36 km by 2025 (7.2 km per year)	Rebuild 7.2 km per year or approximately 6 projects per year

Representative Workbook

Overhead rebuilds

Small Business

Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

Additional Feedback (n=2) 96% of respondents did not provide additional feedback	**n-size**
Reliability/safety outweighs cost	1
Replace within budget/find efficiencies/no increase to consumer	1

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Grid modernization

New technology has changed the way that NPEI can manage and monitor the distribution system.

Supervisory Control and Data Acquisition (SCADA) systems allow NPEI staff the ability to remotely monitor and trace system faults and re-close switches from a control room rather than sending a repair crew to patrol the lines. These systems are particularly effective where there are larger distances between customers, for instance, in more rural areas of the western region of NPEI's service territory.

This equipment can have significant positive impacts on restoration times when an outage does occur, particularly in instances such as during a severe weather event.

On average, since 2014, NPEI has installing approximately two remote devices per year, with focus on more rural, lower density areas. That said, there is an opportunity to install this monitoring and control equipment more quickly or slowly.

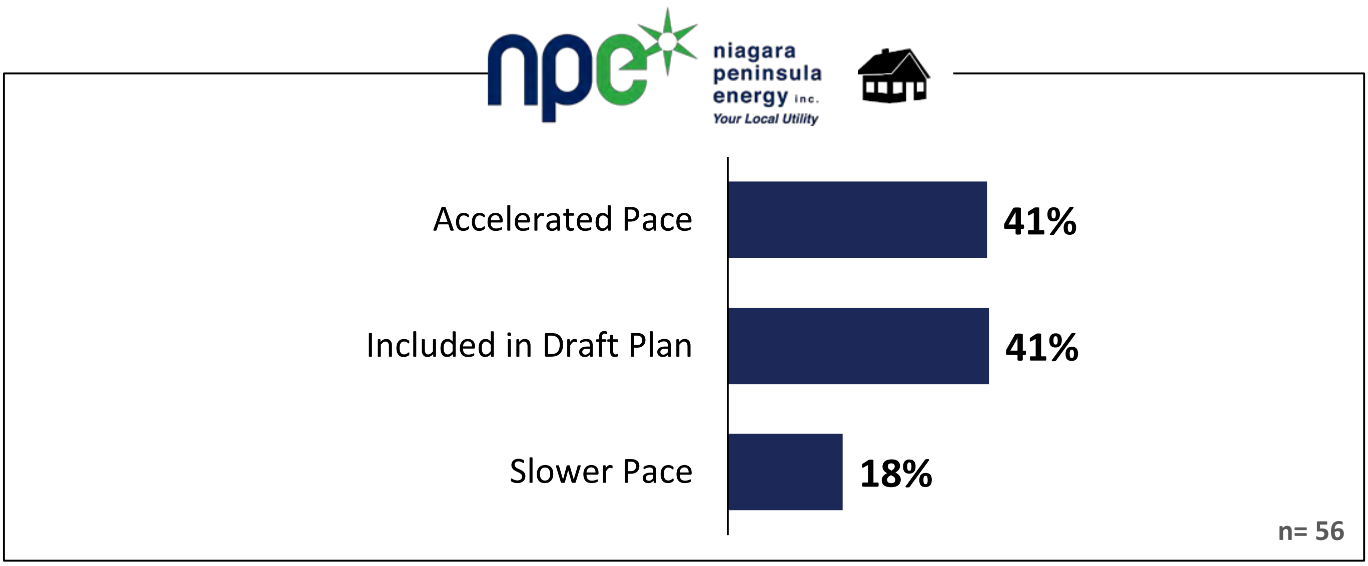
Option	Devices installed	Expected Outcome
Accelerated Pace ***Additional*** *$0.01 per month annually ($0.12 more per year)*	20 devices (4 per year)	NPEI to double installation rate to four devices per year.
Included in Draft Plan *Within proposed average 2.4% increase over 5-years*	10 Devices (2 per year)	Remain at current installation pace of two devices per year. Install new devices to expand NPEI's Smart Grid network. These devices provide better monitoring capability on the system, which leads to improved restoration times during outages.
Slower Pace ***Decrease*** *of $0.01 per month annually ($0.12 less per year)*	5 Devices (1 per year)	NPEI to cut rate of installation in half to one device per year.

Representative Workbook

Grid modernization

Small Business

Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

Additional Feedback (n=2) 96% of respondents did not provide additional feedback	**n-size**
Be proactive/pay now to save later/costs will only increase	1
None	1

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Impact of Choices

Investment Alternative Summary

Throughout this workbook, you have been asked about **seven key choices** that could impact your rates. Below is a summary of your answers to the questions that could impact your rates.

<u>At the bottom of this page you will find the total bill impact of all the answers.</u>

Having seen the total bill impact, please review your answers and change your responses if you desire; your potential rate impact will be re-calculated. You will have the opportunity to continue adjusting your answers until you feel you've reached the best balance for you.

Q Small Business Customer Bill Impact Change and Magnitude of Bill Impact (**MEAN**)

Differences that are statistically significant at 95% are noted by an asterisk (*).

Representative Workbook

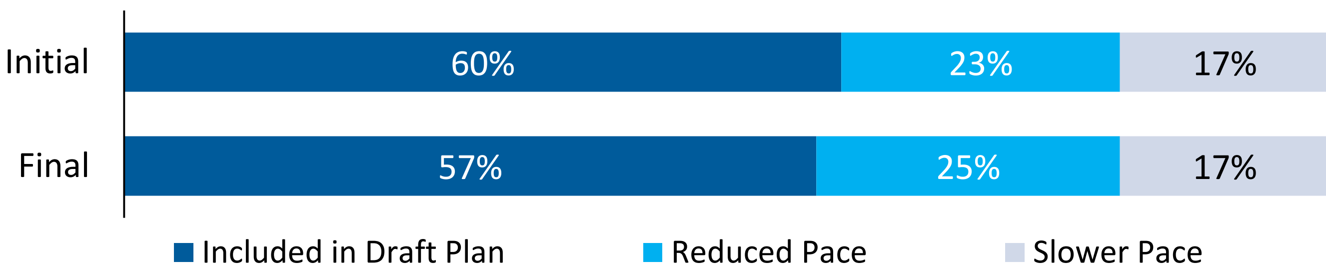
Small Business

Change in Initial vs. Final Response by Project

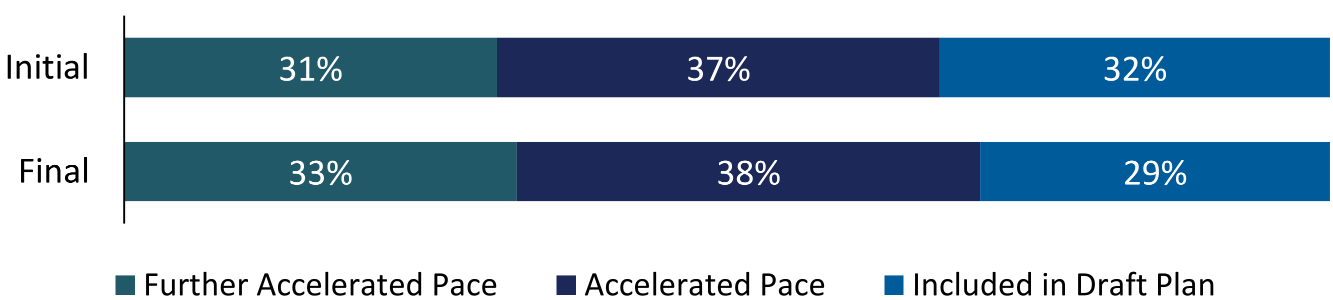
Q Overhead Pole Replacement

Q Overhead Transformer Replacement

Q Converting Outdated Underground Kiosk Transformers



Q Underground Cable Replacement

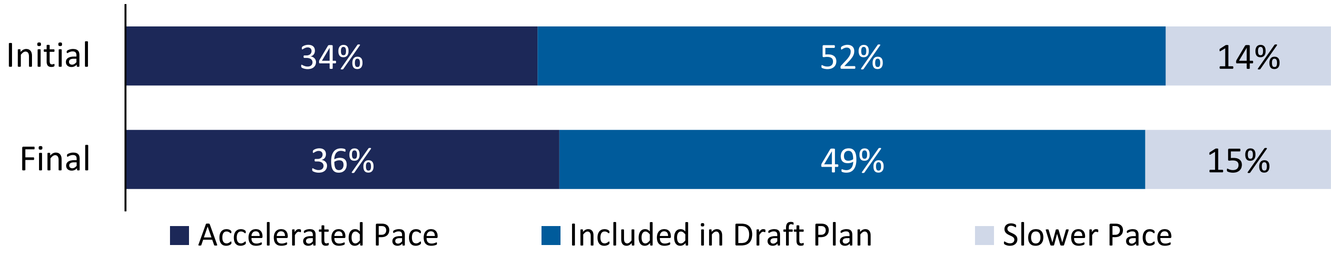


Representative Workbook

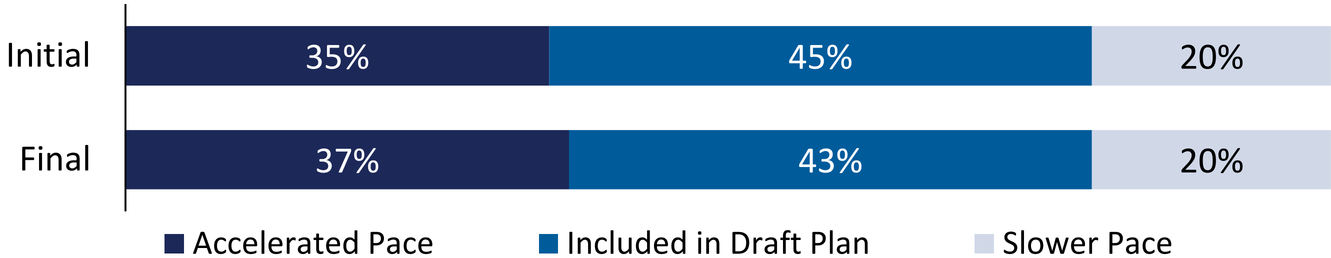
Change in Initial vs. Final Response by Project

Small Business

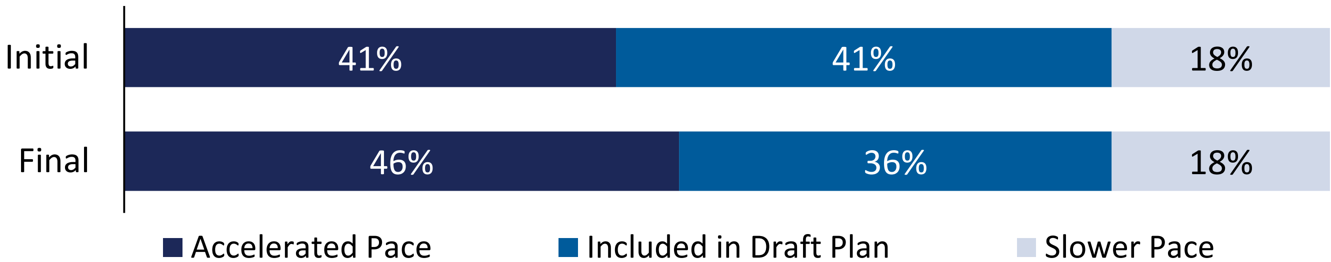
Q Subdivision Underground Rehabilitation



Q Overhead Rebuilds



Q Grid Modernization



INNOVATIVE RESEARCH GROUP

Impact of Choices

Assessing Niagara Peninsula Energy's draft 2021-2025 plan

Again, it is estimated that if NPEI continues with its preliminary plan, the distribution portion of the bill will increase by $4.84 per month in 2021, when the plan is set to come into effect. For the period 2022-2025, the annual bill increase is limited by the OEB to be less than the rate of inflation.

- At the end of the 5-year plan, the typical small business customer would see the distribution portion of their electricity bill increase by $8.46.
- As a result, the distribution charges on the typical small business customer's monthly bill would increase from $69.15 in 2020 to $77.61 by 2025.

Estimated Typical Small Business Annual Increase in Monthly Bill (5 year forecast)

	Year	Average Small Business Bill	Distribution Portion of Bill	Incremental Rate Change	% Change * (on distribution portion of bill)
Current Rate	2019	$298.63	$68.28		
Budgeted Rate	2020	$303.11	$69.15	$0.87	1.27%
Forecast for next rate period	2021	$306.98	$73.99	$4.84	7.00%
	2022	$311.58	$74.88	$0.89	1.20%
	2023	$316.26	$75.78	$0.90	1.20%
	2024	$321.00	$76.69	$0.91	1.20%
	2025	$325.82	$77.61	$0.92	1.20%
				$8.46	

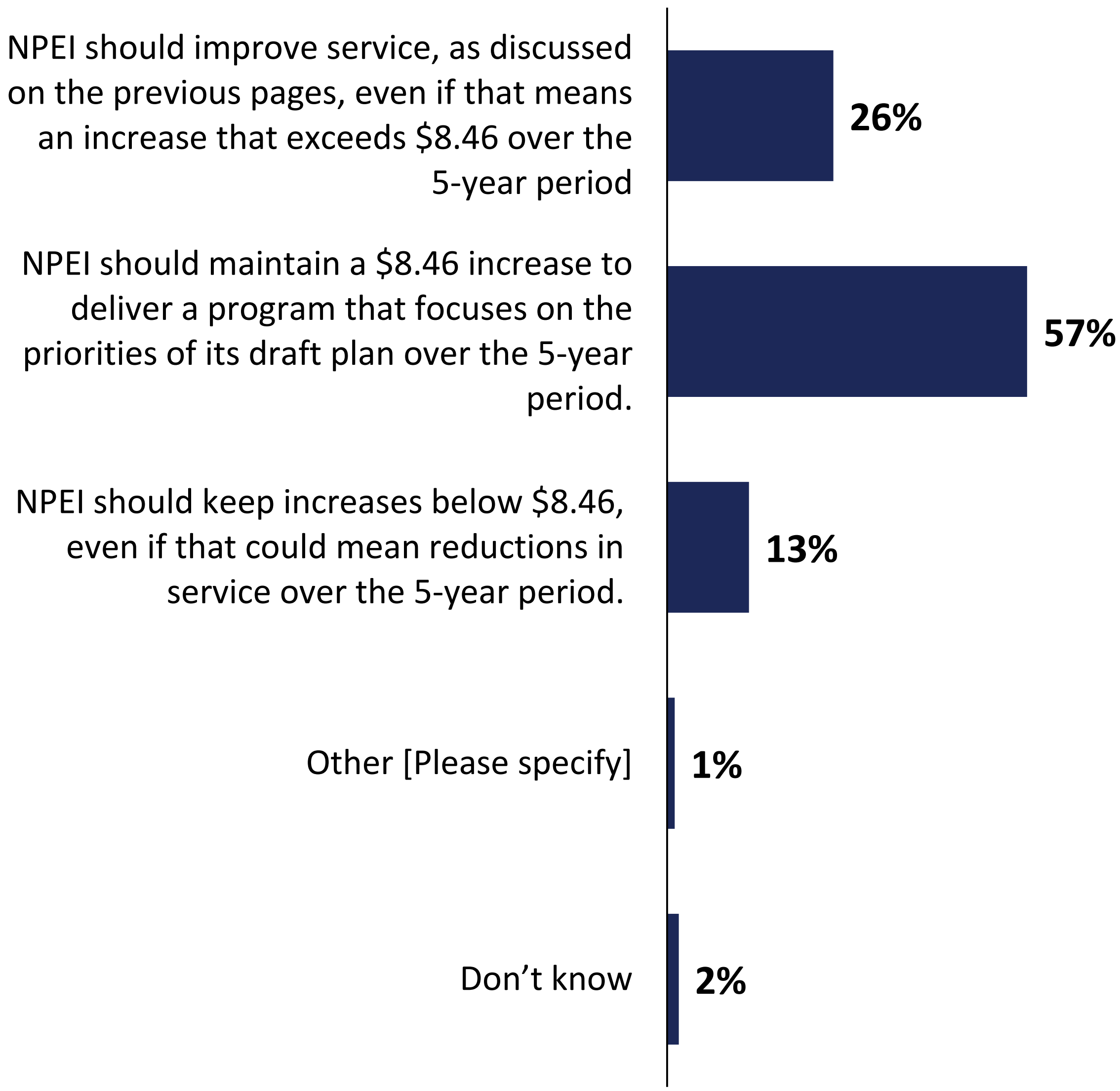
*** These estimates are preliminary, and are subject to your feedback as the business plan is finalized .**

Representative Workbook

Small Business

Assessing Niagara Peninsula Energy's draft 2021-2025 plan

Q Considering what you know about Niagara Peninsula Energy's draft plan – which would see the typical small business customer's distribution portion of their bill increase by $8.46 over the 5-year period – which of the following best represents your point of view?



n=56

Representative Workbook

Final Comments

Q Thinking about your answer to the previous question, why do you feel that NPEI should take that approach over the 2021-2025 period?

Final Comments (n=20) 64% of respondents did not provide additional feedback	**%**
Proactive approach-Pay now to ensure proper maintenance and prevent higher cost in the future	9
Increase is reasonable -taking affordability into account	8
Rates are high enough already/no increase	3
None	1

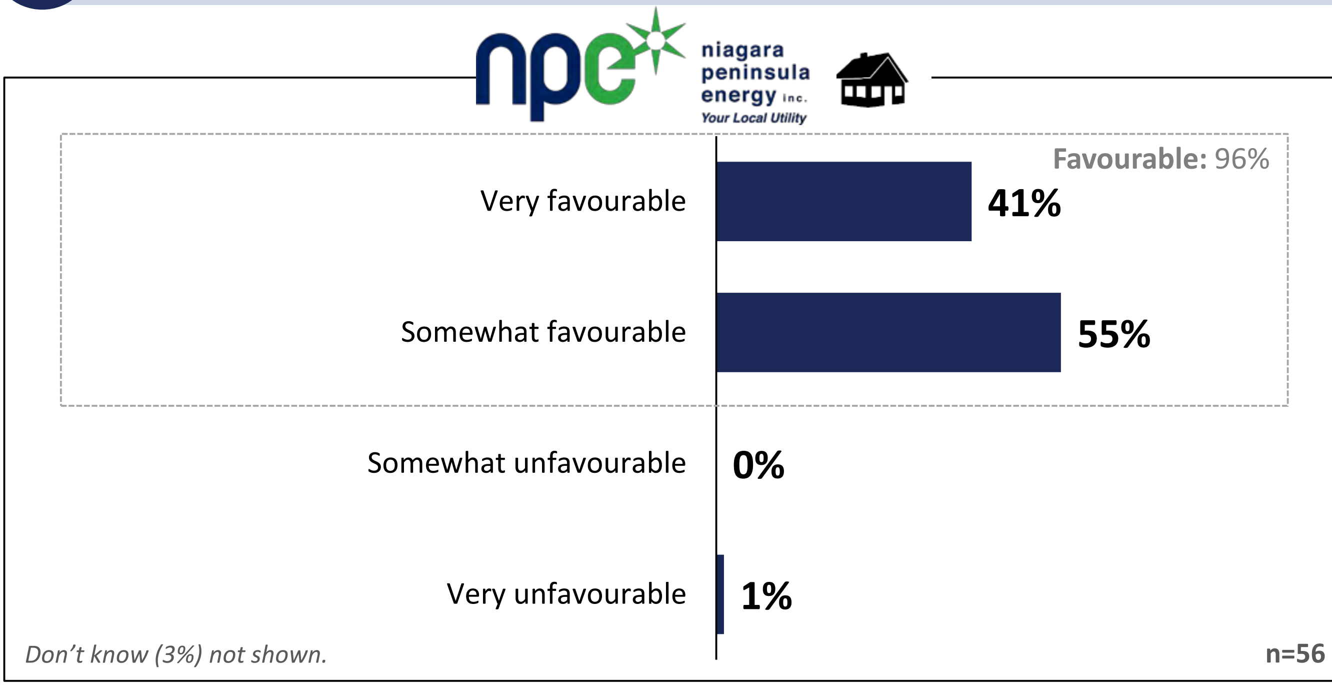
Q Do you have any final comments regarding NPEI or the customer engagement that you just completed?

Final Comments (n=10) 82% of respondents did not provide additional feedback	**%**
Positive - General NPEI/Survey/ asking for Customer input/informative	4
Invest now to avoid higher cost in the future/Maintain and repair accordingly	3
Cost issues/delivery fees/High rates/keep cost low	2
None	1

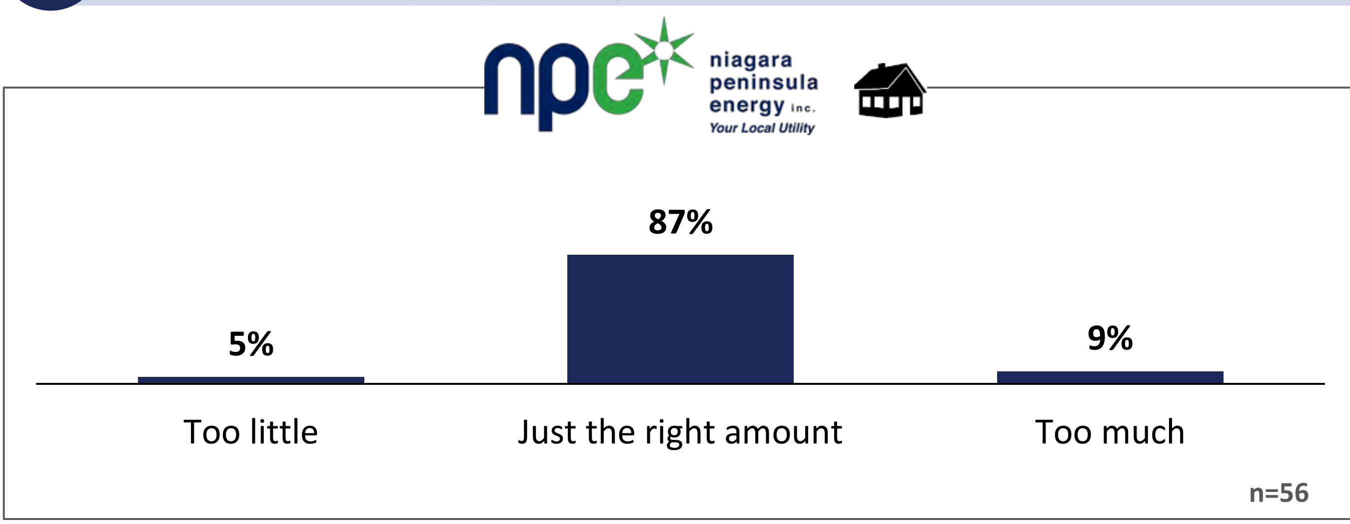
Representative Workbook

Final Thoughts: Workbook Diagnostics

Q **Overall Impression**: Overall, did you have a favourable or unfavourable impression of the consultation you just completed?



Q **Volume of Information:** In this consultation, do you feel that NPEI provided too much information, not enough, or just the right amount?



Representative Workbook

Content Covered and Unanswered Questions

Q Was there any content missing that you would have liked to have seen included in this consultation?

Content Covered (n=56)	%
None	50
Cost/delivery fees/High rates/keep cost low	2
More information on system reliability aging infrastructure/preventative measures	1
Billing issues/clearer breakdown/electronic	1
Other	3

Q Is there anything that you would still like answered?

Unanswered Questions (n=56)	%
None	50
Transparency-Cost allocation	2
Going underground/transformers/lines	1
Consultations with Customers/ updates as to what course of action and plan will be taken	1
Cost issues/delivery fees/High rates/keep cost low	1
Positive - General NPEI/Survey/ asking for Customer input/informative	1

INNOVATIVE
RESEARCH GROUP

Commercial (GS > 50 kW) Customers
Online Workbook Results

Representative Workbook
Survey Design & Methodology

INNOVATIVE was engaged by NPEI to gather input among commercial (GS > 50 kW) customers on preferences on program timing and balancing outcomes. **Pages 115 to 157** show the actual pages of the workbook that was sent and completed by customers. The only additions are the actual results.

Field Dates & Workbook Delivery

The **Commercial Online Workbook** was sent to all NPEI GS > 50 kW customers who have provided the utility with an email address. Customers had an opportunity to complete the workbook between **December 3rd and December 18th, 2019**.

Beyond the initial invite on **December 3rd**, customers were sent multiple reminder emails to encourage participation. Additionally, NPEI staff placed follow-up telephone calls to encourage participation.

Each customer received a unique URL that could be linked back to their annual consumption, region and rate class.

In total, the workbook was sent to **447 GS > 50 kW** customers via e-blast from INNOVATIVE.

Commercial (GS > 50 kW) Online Workbook Completes

A total of **32** (unweighted) NPEI GS > 50 kW customers completed the online workbook via a unique URL.

Individual GS > 50 kW customer responses were anonymous and no identifiable respondent information was shared with NPEI. Responses were combined to protect the confidentiality of individual customers.

Sample Distribution

Due to sample size this data has not been weighted, and is presented in n-sizes rather than percentages. Results should be treated as directional only.

Eligible Sample (Accounts with email addresses)	Completed Workbooks	% of Completed Workbooks vs. Eligible Sample
447	32	7.2%

Total Sample (Unique accounts)	Approximate # of unique accounts represented*	% of Unique Accounts Represented vs. Total Sample
781	74	9.5%

* Based on an analysis of the "total" sample, the 32 completed workbooks represent approximately 74 unique GS > 50 kW accounts or 9.5% of the total sample pool of 781 GS > 50 kW customers.

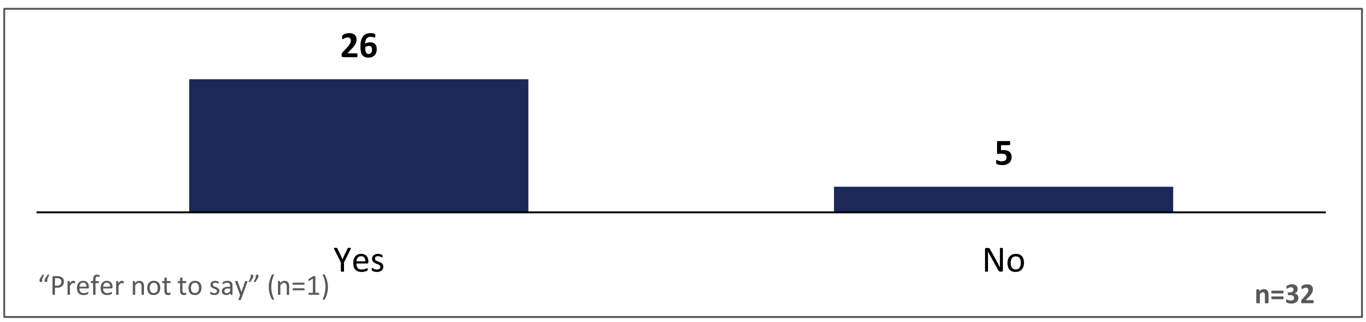
Representative Workbook

Demographic Breakdown

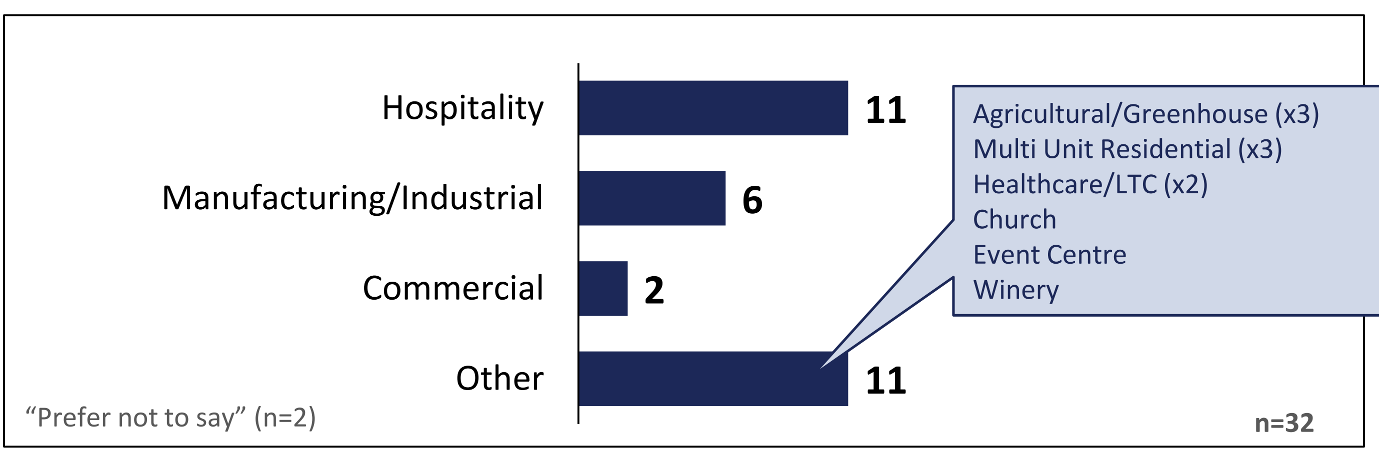
Commercial
GS > 50 kW

Q Company Size

Q Responsibility for Managing or Overseeing Organization's Hydro Bill



Q Sector

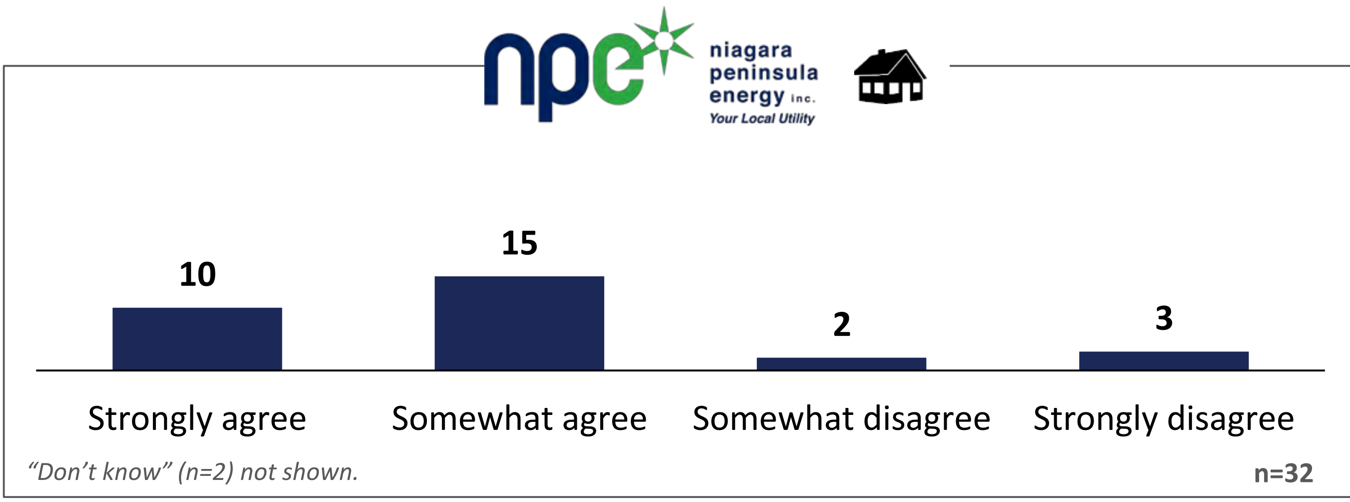


Representative Workbook

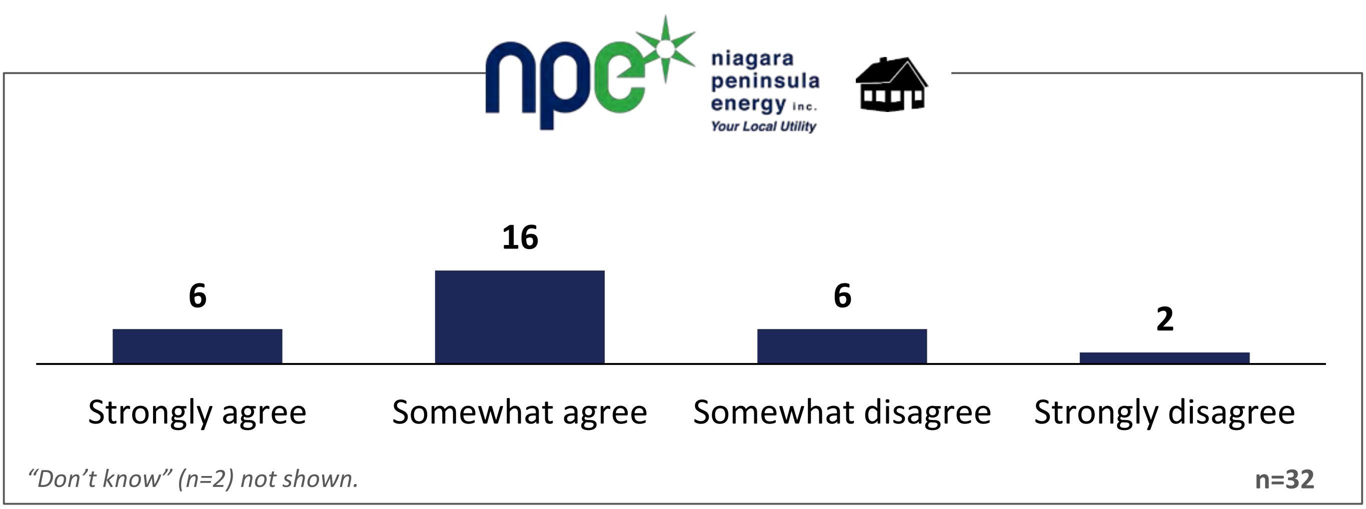
Environmental Controls

Thinking generally about the electricity system in Ontario, including generation, transmission and local distribution, do you agree or disagree with the following statements?

Q The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.



Q Customers are well served by the electricity system in Ontario.



Representative Workbook

Background Information

Commercial
GS > 50 kW

About this Consultation

Welcome to Niagara Peninsula Energy's Customer Engagement!

Niagara Peninsula Energy (NPEI) needs your input on choices that will impact the services you receive and the rates that you pay.

- **NPEI** is developing its investment plan for 2021 to 2025. This plan will determine the investments NPEI will make in equipment and infrastructure; the services it provides; and the rates you pay.
- As **NPEI** plans for the future, they want to ensure their business decisions are aligned with customers priorities, preferences, and needs.
- Throughout this survey, information will be provided in an effort to give you more background on which to base your responses.
- While responding to the following questions, remember that there are no wrong answers, and that your individual responses will remain anonymous.
- This customer engagement will take approximately 25-35 minutes to complete, depending on the level of feedback you wish to provide. Your progress will be saved as you move through the workbook, meaning you can leave and return to the customer engagement at any time.

All individual responses will be kept confidential. Innovative Research Group (INNOVATIVE), an independent research company, has been hired NPEI to gather your feedback.

Those who complete the questions that follow will be invited to enter a draw to win one (1) $500 cash prize.

If you are reading this on a smaller mobile device, you may want to consider accessing the survey from a tablet, desktop or laptop instead so that it is easier for you to read.

Please note that the estimates throughout are for illustrative purposes only and may not reflect the actual size of your organization's monthly electricity bill.

For the purpose of this exercise, the estimates are based on a customer with a monthly demand of 180 kW and monthly consumption of 65,000 kWh.

Representative Workbook

Background Information

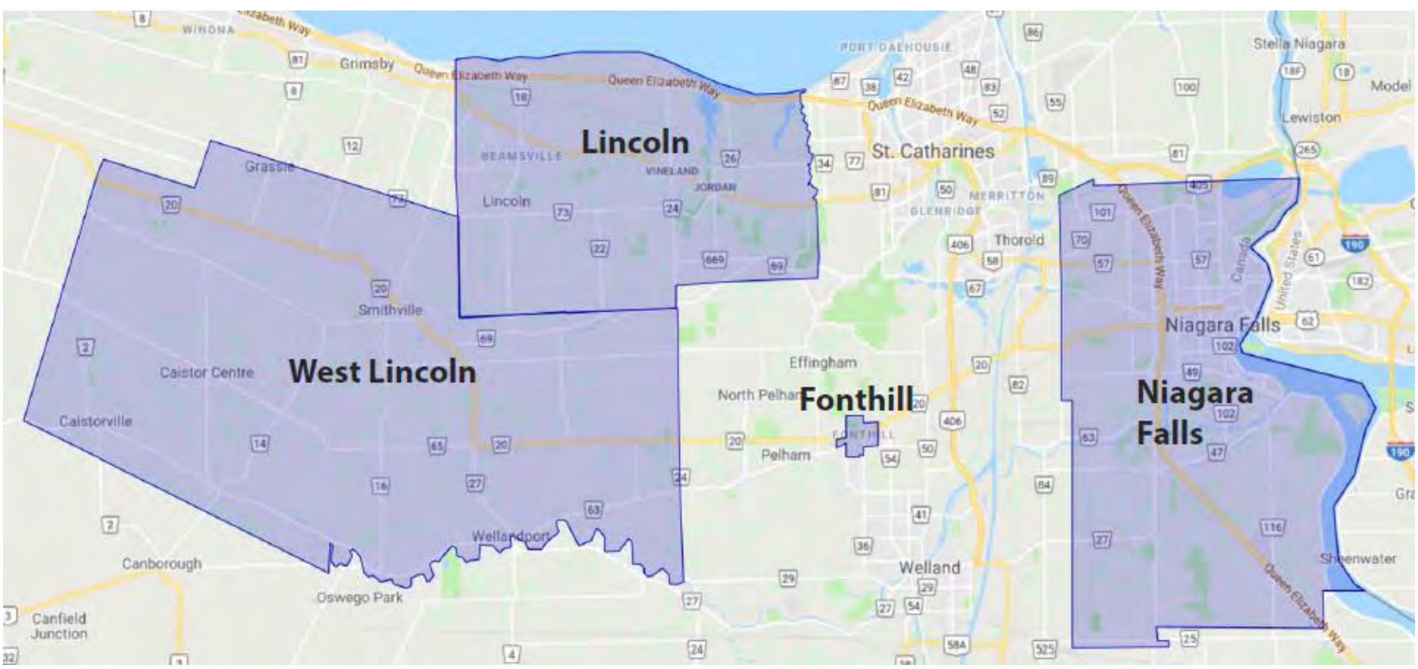
Commercial
GS > 50 kW

Electricity 101

Who is Niagara Peninsula Energy?

NPEI provides local electricity distribution and related services to residential and business customers in the City of Niagara Falls, Town of Lincoln, Town of Pelham, and Township of West Lincoln.

- NPEI serves an area of approximately 827 square kilometers and 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 local distribution company (LDC) and regulated entity, NPEI applies for, and receives approval from the regulator to charge for its services.



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Electricity 101

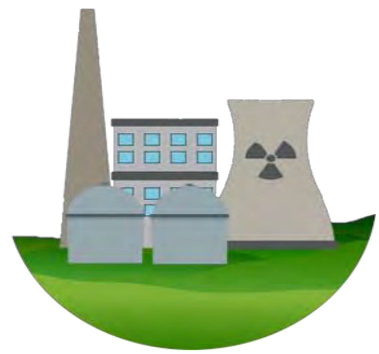
Niagara Peninsula Energy's Role in Ontario's Electricity System

Ontario's electricity system is owned and operated by public, private, and municipal corporations across the province. It is made up of three key components: **generation**, **transmission** and **distribution**.

Generation

Where electricity comes from

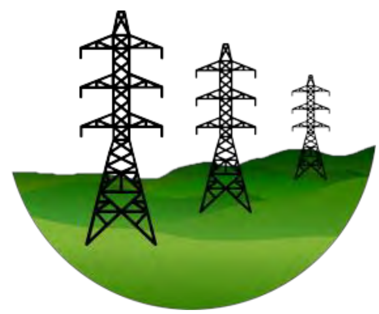
Ontario's electricity is generated using a mix of nuclear, gas-fired, and water power (hydro), as well as biomass and renewable sources such as wind and solar technology. In Ontario, a number of companies own these generating stations but approximately half of the electricity is generated by Ontario 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.



Transmission

How electricity travels across Ontario

Once generated, electricity must be transported to electrical substations 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 kilometres of 'electricity highway', most of which is owned and operated by Hydro One.



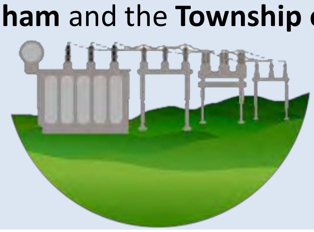
Local Distribution

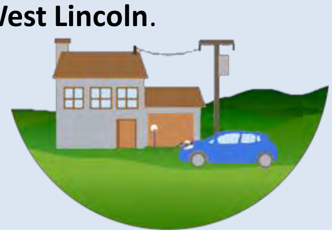
How electricity is delivered to the end-consumer

NPEI is responsible for the last step of the journey: distributing electricity to customers through its distribution system. This local distribution system includes transformer stations that decrease the voltage of the electricity so it can be used safely in your home or business.

There are approximately 1,451 km of overhead power lines and 573 km of underground cable. Through this distribution network, NPEI delivers electricity to approximately 55,600 residential and business customers.

Niagara Peninsula Energy Inc. is jointly owned by the **City of Niagara Falls**, the **Town of Lincoln**, the **Town of Pelham** and the **Township of West Lincoln**.





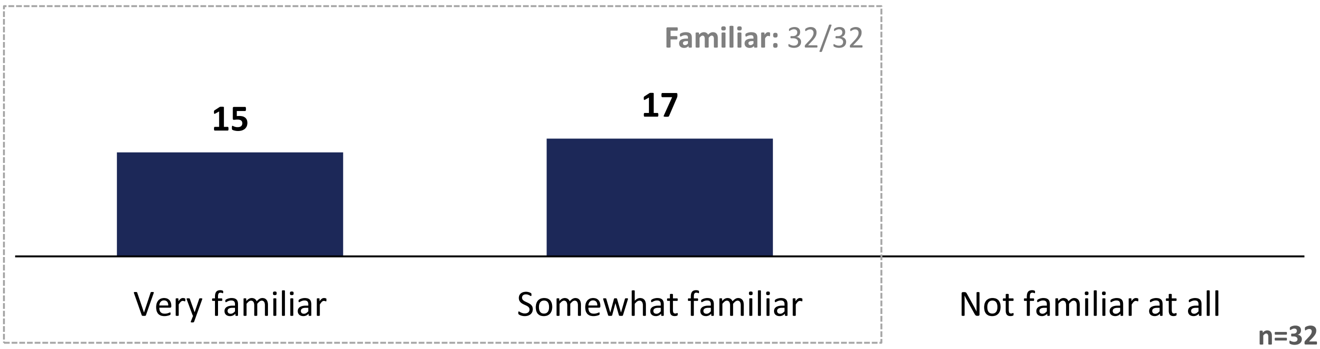
npe niagara peninsula energy Inc.
Your Local Utility

Representative Workbook

Familiarity with Ontario's electricity system

Commercial
GS > 50 kW

Q Before this survey, how familiar were you with Niagara Peninsula Energy, which operates the electricity distribution system in your community?



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Electricity 101

How much of my electricity bill goes to Niagara Peninsula Energy?

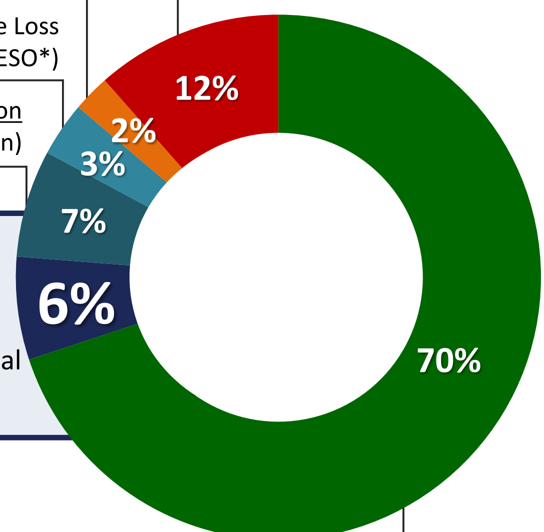
- Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board (OEB), the provincial energy regulator.
- While NPEI is responsible for collecting payment for the entire electricity bill, it retains only the distribution portion of the delivery charge.
- Distribution makes up about **6%** of the typical mid-sized business customer's bill.
- The rest of your bill is passed onto provincial transmission companies, power generation companies, the government and regulatory agencies.

NPEI Sample Monthly Bill*
(Based on 180 kW Monthly Demand)

Account Number:
000 000 000 000 0000

Meter Number:
00000000

Your Electricity Charges	
Electricity	
Electricity Charge	1,202.50
Global Adjustment	6,951.10
Delivery	1,900.21
Regulatory Charges	265.89
Total Electricity Charges	$10,319.71
HST	1,341.56
Total Amount	$11,661.27



Delivery: Distribution
NPEI's typical portion of the total bill is **$738.65**

*IESO = Independent Electricity System Operator

* As of November 1, 2019. Based on typical monthly consumption of 65,000 kWh

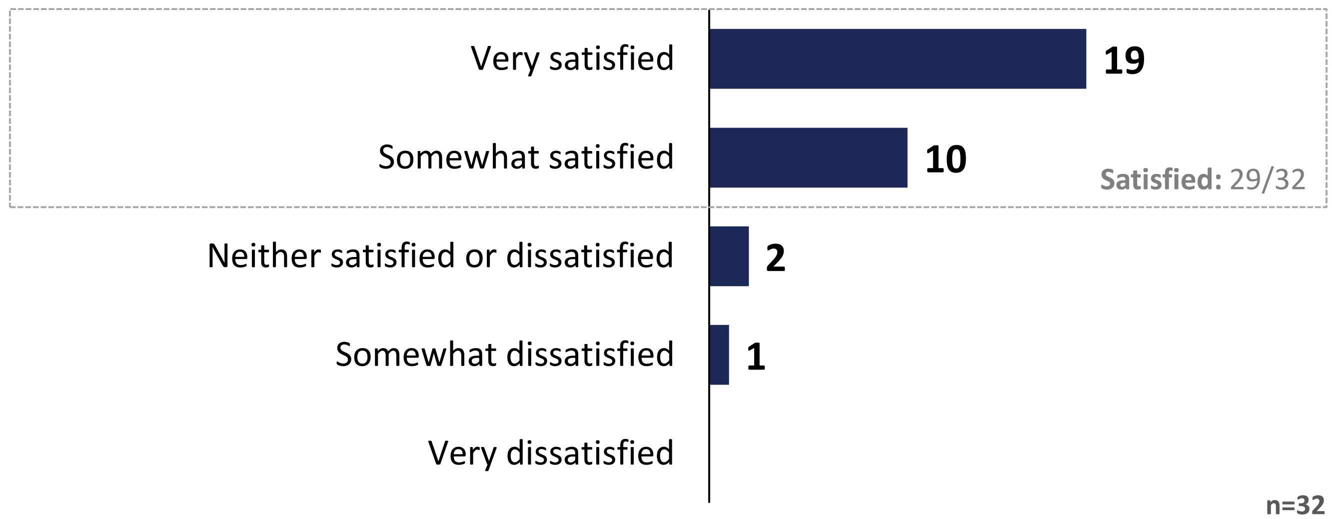
INNOVATIVE RESEARCH GROUP

Representative Workbook

Overall Satisfaction with Niagara Peninsula Energy

Commercial
GS > 50 kW

Q Thinking specifically about the services provided to you and your community by Niagara Peninsula Energy, overall, how satisfied or dissatisfied are you with the services that your organization receive?

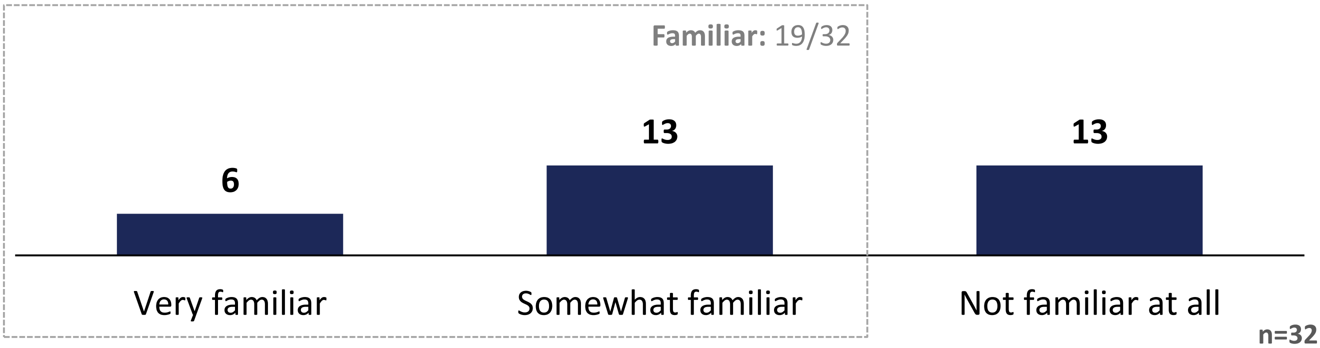


Representative Workbook

Familiarity with Percentage if Bill Remitted to NPEI

Commercial
GS > 50 kW

Q Before this survey, how familiar were you with the amount of your organization's electricity bill that went to Niagara Peninsula Energy?



Q Is there anything in particular you would like Niagara Peninsula Energy to do to improve its services to your organization?

Improving Services (n=6) Verbatim Responses 26/32 of respondents did not provide additional feedback
As a long-term care facility with 231 residents, we rely on a reliable source of electricity, and while we have a generator backup that powers some of our equipment, power outages do cause some issues with the our building systems and computer equipment. We understand that power outages beyond your control do occur, but any tree trimming near hydro lines helps reduce risk.
I would like them to continue doing the retro fit LED program.
Ignoring our "battle" at minimizing the global adjustment which is our main issue I would like our monthly invoices to reach is much sooner than they do now. This is obviously for financial statement purposes.
More Education to their customers.
Ontario electricity rates are too high compared to other provinces. Especially in the Niagara Region where we can generate hydro electric power
The delivery charge on our bill is closer to 50% of the final bill... we have queried this in the past without any success.

INNOVATIVE RESEARCH GROUP

Niagara Peninsula Energy Background

Building Niagara Peninsula Energy's draft plan

NPEI has put together its draft business plan based on the information and input from various sources, such as:

- **Legal and regulatory** requirements by continuing to meet its obligations.
- **Internal business planning** based on expert analysis and professional judgment to develop construction and operations programs that address safety, business, technical, and operational needs.
- **Customer feedback** collected through both ongoing dialogues and specific engagements, such as this.

There are three key organizations responsible for setting the policy direction of Ontario's electricity system. The decisions made by these organizations impact how utilities operate their businesses and serve their customers.

- **Policy**: The Ontario Ministry of Energy, Northern Development and Mines (MNDM) creates energy policy for the province.
- **Regulation**: The electricity industry in Ontario is regulated by the Ontario Energy Board (OEB). One of the OEB's roles is to review the business and distribution plans of all electricity distributors and approve the rates that they charge customers.
- **Operations and Planning**: The Independent Electricity System Operator (IESO) manages the provincial electricity grid, plans for the province's future energy needs, and develops conservation programs.

Ontario ENERGY /ÉNERGIE

ONTARIO ENERGY BOARD

ieso Connecting Today. Powering Tomorrow.

Niagara Peninsula Energy Background

How did customer feedback shape Niagara Peninsula Energy's draft plan?

NPEI is placing more emphasis on incorporating customer feedback into the planning process than ever before.

NPEI engages with its customers both in day-to-day interactions and in a variety of customer engagement activities. These interactions help identify customer needs and preferences, and inform how the utility plans for the future.

This past summer, NPEI engaged with **thousands of residential and business customers** from across its service territory – both in person and through telephone and online surveys.

What did NPEI hear from customers like yourself?

1. The clear majority of NPEI residential and small business customers are satisfied with the current service they receive. When asked how NPEI can improve service, top responses for residential customers were "nothing", followed by "lower or reduce rates".

2. Among competing outcomes, **price**, **reliability**, and **finding internal cost efficiencies** are the top three priorities for both residential and small business customers.

3. While keeping price at a reasonable and affordable level is an important priority, many customers feel that investing in the grid to maintain reliability, is preferable to deferring investments to keep bills low.

Considering this feedback, as well as the information and inputs discussed on the previous page, NPEI has developed a draft plan that is responsive to:

1. Legal requirements by continuing to meet its obligations, including safety and reliability;

2. A transformer station upgrade to accommodate the new Niagara South Hospital and future surrounding growth.

3. Mandatory service connections to accommodate new customers and customer-required upgrades, of which NPEI does not have control over how and when these costs are incurred.

4. Customer feedback by:

    a) Keeping distribution price increases as low as possible;

    b) Maintaining long-term performance for customers experiencing average or better service;

    c) Improving service levels for customers experiencing below average service or who have special reliability needs (e.g. hospitals); and,

    d) Balancing other customer priorities (e.g. customer service) with the need to contain rate increases.

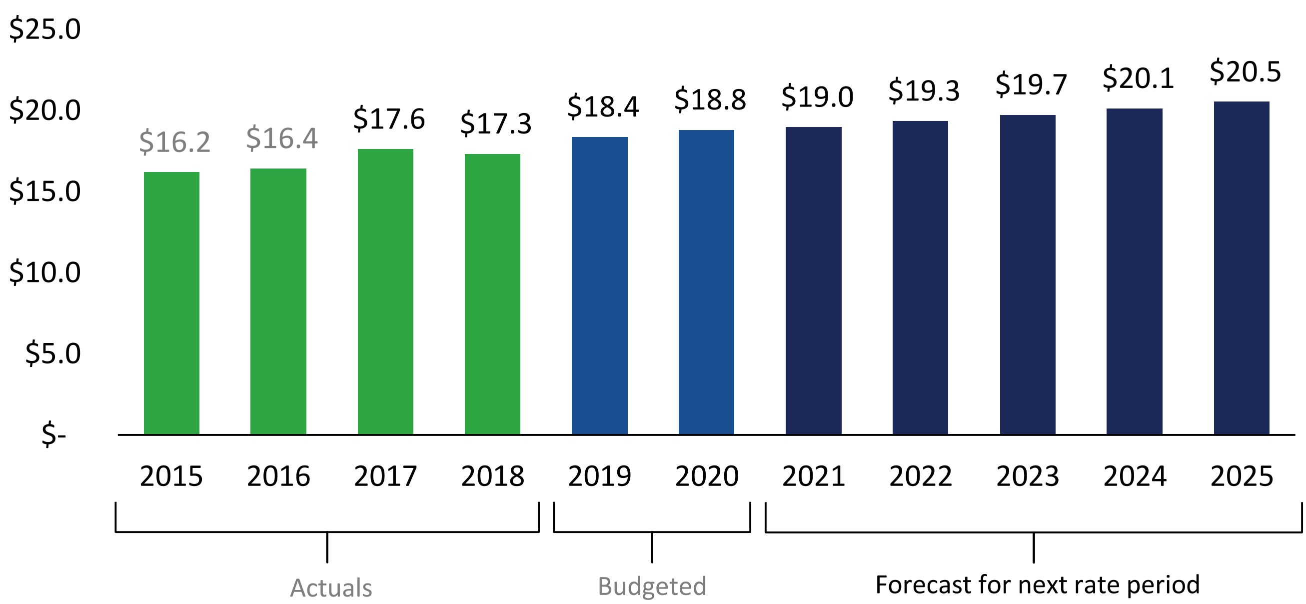
Niagara Peninsula Energy Background

Operating Expenses

In this section, we want to focus on operating expenses and how NPEI compares to its peers.

NPEI's operating budget covers recurring expenses, such as the maintenance of poles, wires, transformers, fleet and buildings as well as proactive maintenance programs such as tree trimming, and payroll for employees. Meter reading, postage, cyber security and hardware/software maintenance expenses are billing and customer service-related expenses. The proposed 5-year plan, between 2021 and 2025, would see NPEI spend an estimated total of $98.7 million on operations.

NPEI's Current and Forecasted Operating Expenses, per Year (Millions)*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

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NPEI's **operating costs** are benchmarked by the OEB against other utilities in Ontario. In the last year of publicly available data collected by the OEB, NPEI's operating costs per customer was **$311.67**, which is slightly more than some, while less than both Hydro One and Canadian Niagara Power.

2018 Operating & Maintenance and Administration (OM&A) Per Customer ($)

The diverse geographical nature of NPEI's service territory, which is a mix of urban and rural communities is a large consideration/driver of these OM&A costs. In some parts of the service territory, there may be less than 30 customers per kilometer of line. Despite low density, these lines still require the same level of ongoing maintenance, including tree trimming and other expenses that contribute to operating the system; thereby resulting in a higher cost per customer.

Niagara Peninsula Energy Background

Operating Expenses

Recall, this customer feedback portal does not ask questions that expect you to be an electricity expert.

The OEB runs an open and transparent review process where experts from the OEB and intervenor groups review and challenge NPEI's analyses and assessments. You are welcome to participate in the OEB process if you are interested in those issues. Details can be found at oeb.ca/participate.

This customer engagement however, is focused on capital investments.

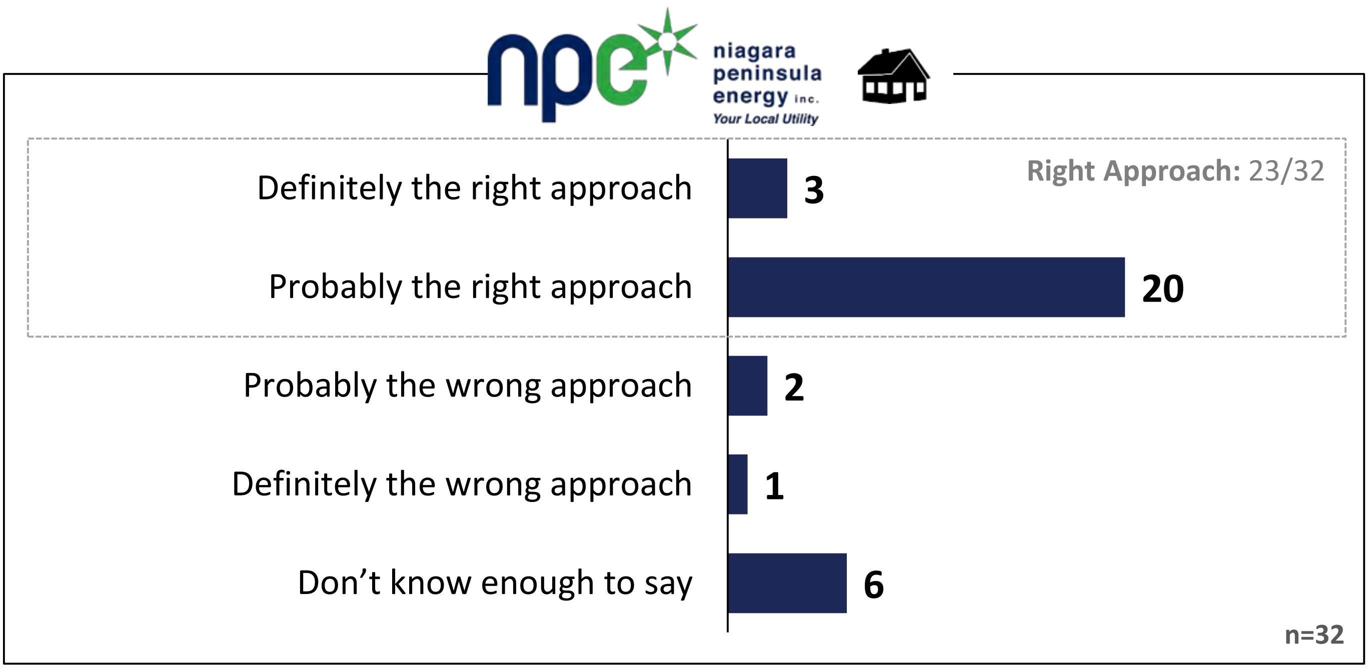
Detailed discussion of NPEI's operating budget is left to experts from the OEB and intervenors in the formal rate application review; this workbook focuses on collecting your view on competing trade-offs in capital investments.

Representative Workbook

Approach to Operating Expenses

Commercial
GS > 50 kW

Q Does leaving the detailed discussion about Niagara Peninsula Energy's operating budget to experts from the OEB and intervenors seem like the right approach or wrong approach to you?



And why do you leaving the detailed discussion about NPEI's operating budget to the OEB and intervenors is the wrong approach? Amongst those who say "wrong approach", n=3
NPEI knows their business better than anyone
I don't trust the OEB to make the best decisions
I think from our information we receive from our local hydro NPEI, that the Ontario Energy Board is their regulator who should only oversee, I want to know how much does it cost NPEI to do these every 5 years to the OEB and Why do we need extra intervenors who are probably paid lobbyists for specific sectors. Listen to the customers NOT paid lobbyists which NPEI surveys us anyways.

INNOVATIVE RESEARCH GROUP

Niagara Peninsula Energy Background

Capital Investments

NPEI's **capital budget** covers items that, once purchased, have lasting benefits over many years. Year-over-year, regardless of external drivers, NPEI will need to make investments in the core distribution system, including poles, wires, cables and transformers.

Based on initial customer input and the approach outlined previously, NPEI believes the capital expenditure required to address system renewal, maintain system reliability and safety, and invest in other infrastructure priorities between 2021 and 2025 is estimated to be **$70.3 million**.

NPEI classifies the costs of four types of capital investment between 2021 and 2025. Each of these four investment categories helps NPEI pace and prioritize projects.

2021-2025 Forecasted Capital Investments

System Renewal ($38.2 million)

These projects are a mix of planned end-of-life replacements and emergency replacements.

Projects Include: Replacement of existing overhead wires, poles, and pole mounted transformers, underground cables and transformers and transformer station upgrades.

System Access ($17.1 million)

"Must do" investments that respond to customer requests for new connections or new infrastructure development.

Projects Include: NPEI's share of new subdivisions, new upgraded commercial and industrial services, and relocating assets based on road infrastructure needs.

General Plant ($8.4 million)

These are investments needed to support the distribution system, such as tools, vehicles, buildings, and computers.

Projects Include: Financial and customer IT systems, enhanced cyber security investments, facility renovations, backup generation, and vehicle replacements.

System Service ($6.6 million)

These investments consist of projects that address capacity constraints, improve system reliability and customer service.

Projects Include: Installation of automated switches and system expansion to supply new development.

Niagara Peninsula Energy Background

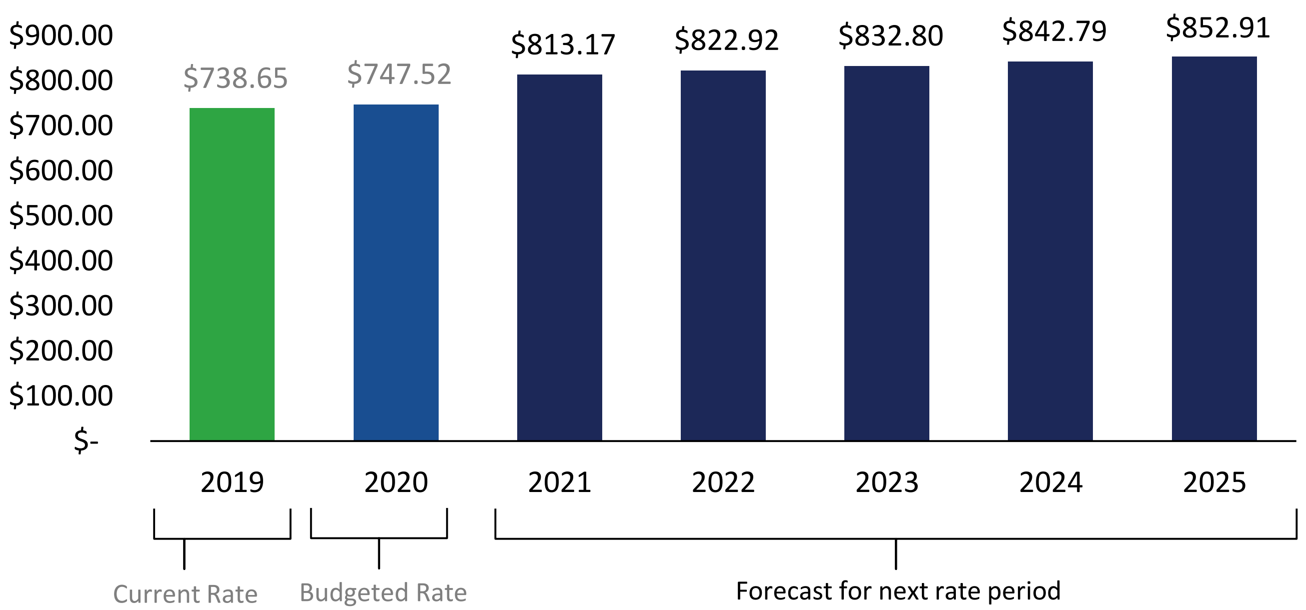
How much will this draft plan cost me?

Remember, the current typical NPEI mid-sized business customer's electricity bill is about $11,600 per month, of which $738.65 goes to NPEI.

It is estimated that if NPEI continues with its preliminary plan, the distribution portion of the bill will increase by $65.65 per month in 2021, when the plan is set to come into effect. For the period 2022-2025, the annual bill increase is limited by the OEB to be less than the rate of inflation.

- At the end of the 5-year plan, the typical mid-sized business customer would see the distribution portion of their electricity bill increase by $105.39.
- As a result, the distribution charges on the typical mid-sized business customer's monthly bill would increase from $747.52 in 2020 to $852.91 by 2025.

Estimated Mid-Sized Business Monthly Distribution Charge, per Year*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

NPEI is looking for your input on its preliminary plan to ensure it is making the spending decisions that matter to you, the customer.

The following sections of this workbook will explore some of the choices Niagara Peninsula Energy needs to make to help finalize its preliminary plan.

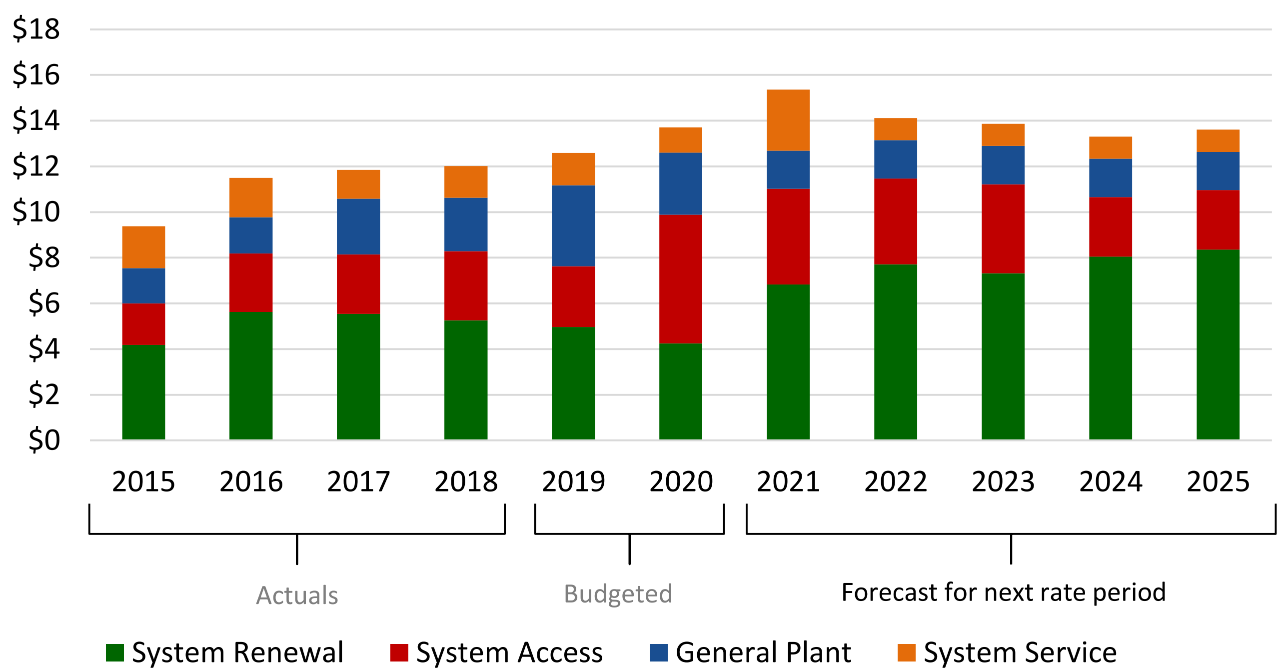
Niagara Peninsula Energy Background

Pacing Capital Investments

The overall amount NPEI invests in capital projects remains generally the same year over year, but what does change is where these investments are made. In some years, when unplanned or unforeseen investments are needed, NPEI will re-allocate funds to make room for these projects within the approved budget. This helps limit the overall amount that the distribution charges fluctuate year-over-year.

The chart below outlines NPEI's spending in past years, and proposed spending for the 5-year period 2021 to 2025.

2015 – 2025 Historical and Forecasted Capital Investments*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

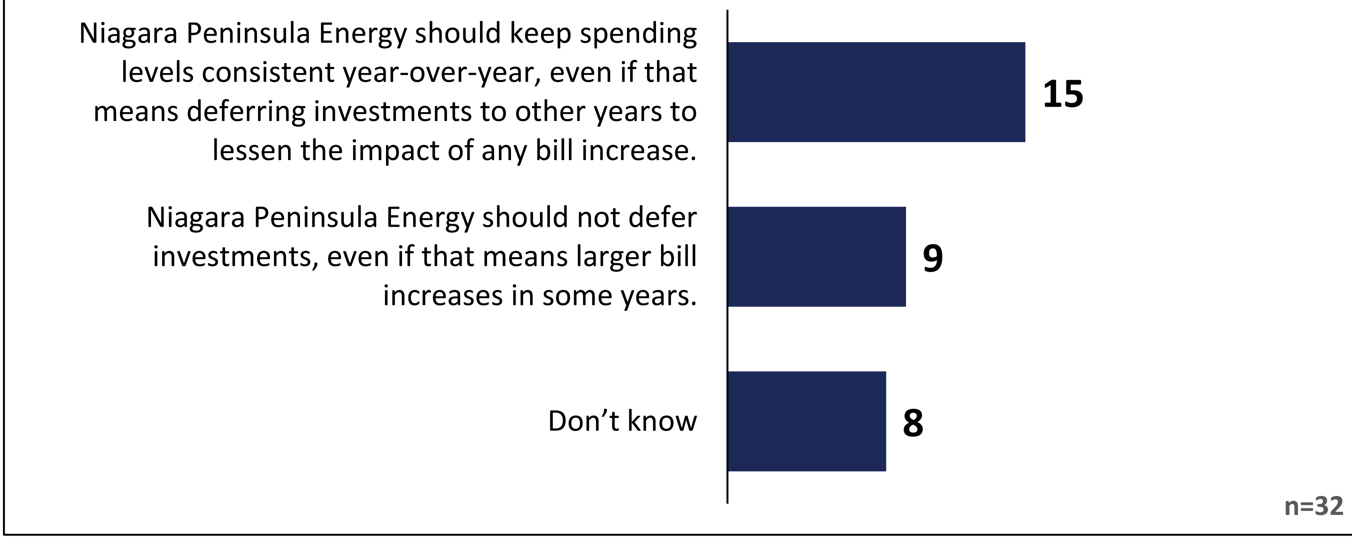
System Access expenditures are budgeted to increase to $5.6M in 2020 to accommodate a number of large commercial customer growth projects as well as municipal road work.

Representative Workbook

Approach to Pacing Investments

Commercial
GS > 50 kW

Q Which of the following statements best represents your point of view regarding Niagara Peninsula Energy's approach to pacing investments?



Q Additional Feedback (Optional)

Additional Feedback (n=6) Verbatim Responses 26/32 of respondents did not provide additional feedback
Again, review your billings the amount you are getting is not 6% it is ten times higher.
And like every successful business watching the pennies helps watch the dollars try not to spend frivolously money that isn't yours
Any of this should be decided on a ROI basis.
As a business you need to invest as infrastructure over years needs to upgraded to keep to a standard level, however, keeping in mind weather incidents are occurring more frequently therefore investing in infrastructure, poles & wires and upcoming renewables that will be more important in the future - Storage, micro grids, renewables. Hydro is an ESSENTIAL service to our business operations.
Due to the ever increasing cost of hydro within the province they need to minimize price increases until as such time the debt is lowered thus paying less interest on the debt whereas they can than slowly start to increase prices slowly to increase their budget to allow them what they need to do. We are paying far too much for hydro in this area.
The options provided are too simplistic. A case by case decision should be applied but in general I would support not deferring investments if in the long-term these investments would be beneficial

Niagara Peninsula Energy Background

Mandatory Investments

Federal, provincial, and municipal governments as well as regulators set requirements and standards that NPEI must satisfy. Mandatory investments can be broken down into three categories:

- **Connecting customers**: This includes connecting customers to the grid when a new home or building is constructed or modified.
- **Moving equipment**: This includes moving equipment like poles and cables for road widening.
- **Mandated obligations**: This includes installing and maintaining customer meters and transferring electricity from the provincial transmission system.

These mandatory investments mean that about **one-in-four dollars (23%)** of your distribution rates over the past five years have not been available for other non-mandatory investments. Looking forward to the 2021-2025 period, NPEI forecasts a similar level of mandatory investments, driven largely by:

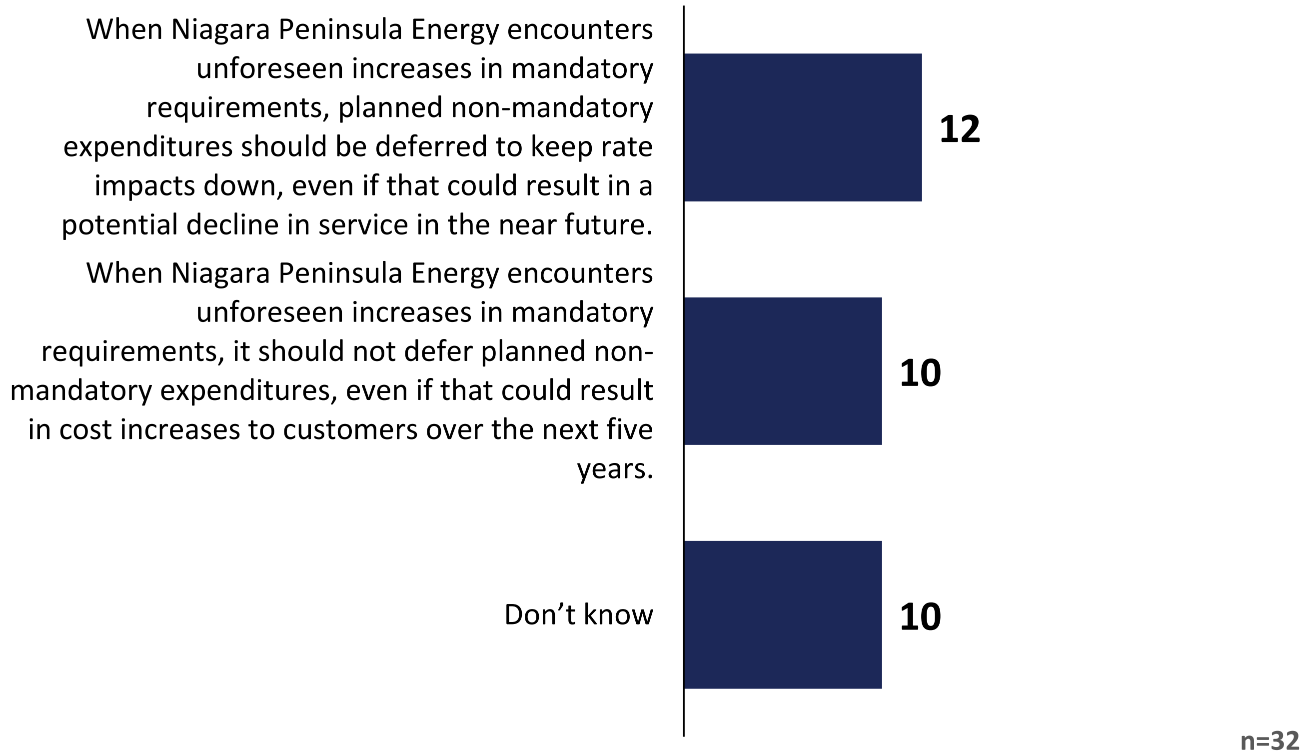
- **Preparing to connect the new Niagara South hospital;**
- **Work to accommodate the 2021 Canada Summer Games in the Niagara Region, and;**
- **Work to accommodate growth and future electricity capacity needs.**

Representative Workbook

Approach to Mandatory Investments

Commercial GS > 50 kW

Q Which of the following statements best represents your point of view regarding Niagara Peninsula Energy's approach to mandatory and non-mandatory spending?



Additional Feedback (n=6) Verbatim Responses 26/32 of respondents did not provide additional feedback
Again...options provided are too simplistic. Must be decided on a case by case basis.
Case by case basis except for mandatory if I understand the word properly.
Hire smarter people nothing is unforeseen
Service is very important to long-term care. However, we are also very sensitive to large price fluctuations as we are non-profit, charitable, and dependent on the Ontario government for much of our funding.
We need the service, what are we talking a $2 coffee increase year to year instead of 5 years to wait, need to modernize this cost of service procedure, not even our business plans are 5 years anymore- 2 years, keep it to inflation year over year instead of big jump in 5 years and if these non-mandatory spending occurs the adjustments are easier to do for both NPEI and probably the regulator.
Your question does not make sense.

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Making Choices (1 of 7)

Overhead Pole Replacement

A recent asset health condition assessment shows that **575 or approximately 3%** of the poles in NPEI's distribution system are in *poor* or *very poor* condition. Each year, new poles enter this condition, and NPEI takes an approach that proactively replaces poles as to not create a large backlog. As a general rule, pole failure only causes an outage when something happens outside of the utility's control, most frequently due to trees knocking them down or a car accident.

On average, since 2014, NPEI has replaced approximately 88 poles per year. This pace has effectively maintained reliability over this period.

NPEI is proposing to replace most of these 575 poles in poor and very poor condition over the course of the next five years, however, there is an opportunity to replace these poles more quickly or slowly. NPEI must continue to invest in overhead pole replacement, therefore, this is a matter of whether customers would rather pay more during the upcoming period, or push some level of investment beyond the next five years.

Option	**Poles Replaced**	**Expected Outcome**
Accelerated Pace ***Additional*** *$0.52 per month annually ($6.24 more per year)*	1,000 by 2025 (200 per year)	Address the very poor and some of the poor condition poles identified in the Asset Condition Assessment.
Included in Draft Plan *Within proposed average 2.7% increase over 5-years*	500 by 2025 (100 per year)	Address most of the very poor condition poles identified in the Asset Condition Assessment and annual pole inspections by 2025.
Slower Pace ***Decrease*** *of $0.25 per month annually ($3.00 less per year)*	250 by 2025 (50 per year)	Address only the poles in need of immediate replacement, as identified in the annual pole inspection report.

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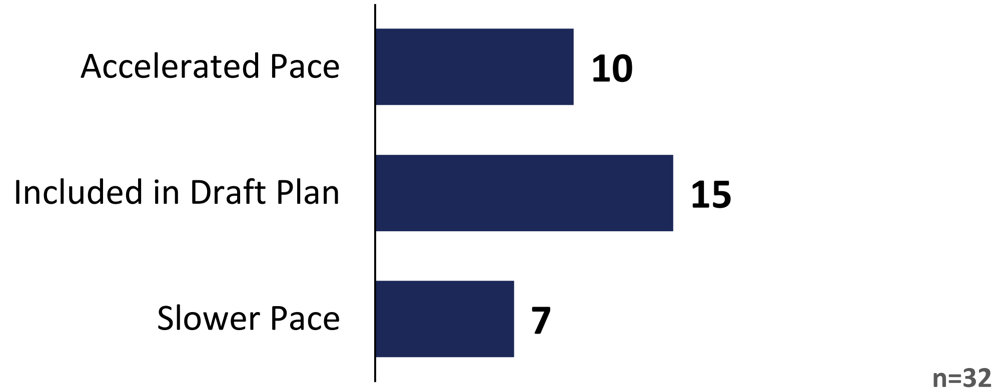
Overhead Pole Replacement

Commercial
GS > 50 kW

Q Which of the following options do you prefer?



Additional Feedback (n=3) Verbatim Responses 29/32 of respondents did not provide additional feedback
Invest in underground moving forward instead of replacing pole to pole. In the long run it costs more if we don't invest up front.
Is your cost including the cost of money whether borrowing or not earning interest? I would take the slowest pace if it does not impact service but I'm not sure that's true.
Why are you replacing poles, put this infrastructure under ground. Also why would you leave very poor poles up?

Making Choices (2 of 7)

Overhead transformer replacement

Transformers are a critical piece of distribution equipment that reduce voltage from the higher levels that are more efficient to move electricity long distances to lower levels that are safer to connect to homes and businesses. They are typically either located on the ground, in underground vaults, or attached to distribution poles

A recent asset health condition assessment shows that **1,251 or approximately 21%** of the overhead transformers in NPEI's distribution system are in poor or very poor condition.

Since 2014, overhead transformer failure has directly resulted in approximately 15 outages per year. That said, in most cases, when an overhead transformer fails, it only impacts a small amount of customers and the equipment can be replaced within 2-3 hours depending on the circumstances.

However, when these outages do occur, it can take NPEI crews an extended period of time to replace the cable and restore power to affected households and businesses.

NPEI is proposing a new program to proactively replace **250 of the 677 or 37%** of the overhead transformers identified as very poor condition before they fail over the course of the next five years.

As with distribution poles, NPEI will proactively invest in overhead transformer replacement, therefore, this is a matter of whether customers would rather pay more during the upcoming period, or push some level of investment beyond the next five years.

Option	Transformers Replaced	Expected Outcome
Accelerated Pace ***Additional*** *$0.18 per month annually ($2.16 more per year)*	375 by 2025 (75 per year)	Address some of the polemount transformers identified as very poor in the Asset Condition Assessment report.
Included in Draft Plan *Within proposed average 2.7% increase over 5-years*	250 by 2025 (50 per year)	Address some of the polemount transformers identified as very poor in the Asset Condition Assessment report.
Slower Pace ***Decrease*** *of $0.16 per month annually ($1.92 less per year)*	125 by 2025 (25 per year)	Address only the worst of the polemount transformers identified as very poor in the Asset Condition Assessment report.

Representative Workbook

Overhead transformer replacement

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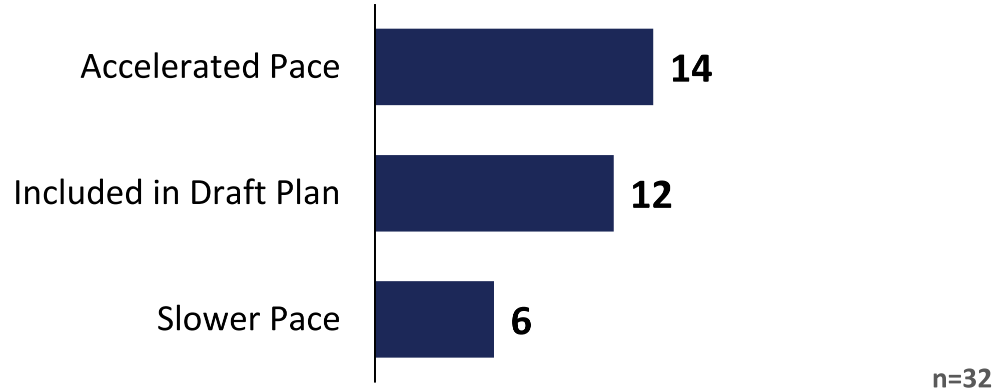
Q Which of the following options do you prefer?

niagara peninsula energy inc. Your Local Utility



Additional Feedback (n=3) Verbatim Responses 29/32 of respondents did not provide additional feedback
Why overhead to overhead, not effective anymore with all these wind and weather related incidents.
Same as pervious answer.
Again, why are poor transformers still there.... this infrastructure needs to be moved underground.

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Making Choices (3 of 7)

Converting Outdated Underground Kiosk Transformers

NPEI's system features a type of underground transformer that was popular in the 1940s to 1970s which no longer meets construction and safety standards. While this equipment still functions, it is becoming increasingly difficult to safely and effectively maintain. When this equipment does fail, it can result in lengthy outages due to the limited accessibility due to the original method of construction.

On average, since 2014, NPEI has converted approximately 9 kiosk transformers per year. Between 2018 and 2019, the pace of this program has been pushed off, and today, there remains 75 transformers in need of replacement.

NPEI is proposing to convert all of this equipment within the next seven years, with 55 being converted in the next five year period. That said, there is an opportunity to convert these kiosk transformers more slowly.

Option	Transformers Installed	Expected Outcome
Included in Draft Plan *Within proposed average 2.7% increase over 5-years*	55 by 2025 (11 per year)	Work towards eliminating all old installations over the next 7 years.
Reduced Pace ***Decrease*** *of $0.40 per month annually ($4.80 less per year)*	25 by 2025 (5 per year)	Work towards eliminating all old installations over the next 15 years.
Slower Pace ***Decrease*** *of $0.61 per month annually ($7.32 less per year)*	10 by 2025 (2 per year)	Work towards eliminating all old installations over the next 35 years.

Representative Workbook

Converting Outdated Underground Kiosk Transformers

Commercial
GS > 50 kW

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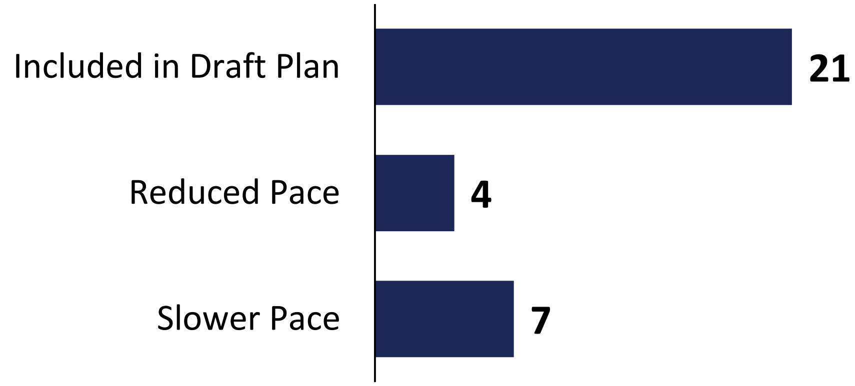
Q Which of the following options do you prefer?



n=32

Additional Feedback (n=2) Verbatim Responses 30/32 of respondents did not provide additional feedback
UNDERGROUND!
Same as pervious answer.

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Making Choices (4 of 7)

Underground cable replacement

Many neighbourhoods across NPEI's service territory are serviced by underground cables. Historically, NPEI has taken a "run-to-failure" approach with this equipment; that is, a cable will be replaced only once it has failed. The age of this equipment is now becoming a concern, with approximately 78 km or 18% of underground cable operating beyond its estimated useful life of 35 years.

Since 2014, underground cable failure has directly resulted in approximately ten outages per year, and when these outages do occur, it can take NPEI crews an extended period to replace the cable and restore power to affected households and businesses.

Between 2021 and 2025, NPEI is proposing a new program that will replace cable that has been identified as past end of life when completing other associated work. NPEI believes that this could help reduce the number and length of outages caused by underground cable failure, as well as to start getting ahead of the ongoing age issue. That said, there is an opportunity to take a more proactive approach to addressing some of the older cable in the system.

Option	Km of cable installed	Expected Outcome
Further Accelerated Pace ***<u>Additional</u>*** *$2.64 per month annually ($31.68 more per year)*	24 km by 2025 (4.8 km per year)	Proactively replace more of the cables identified as past end of life in the Asset Condition Assessment Report.
Accelerated Pace ***<u>Additional</u>*** *$1.21 per month annually ($14.52 more per year)*	12 km by 2025 (2.4 km per year)	Proactively replace some of the cables identified as past end of life in the Asset Condition Assessment Report.
Included in Draft Plan *Within proposed average 2.7% increase over 5-years*	2 km by 2025 (0.4 km per year)	Replace cables past end of life as other work is being completed on associated switchgear or riser poles.

Representative Workbook

Underground cable replacement

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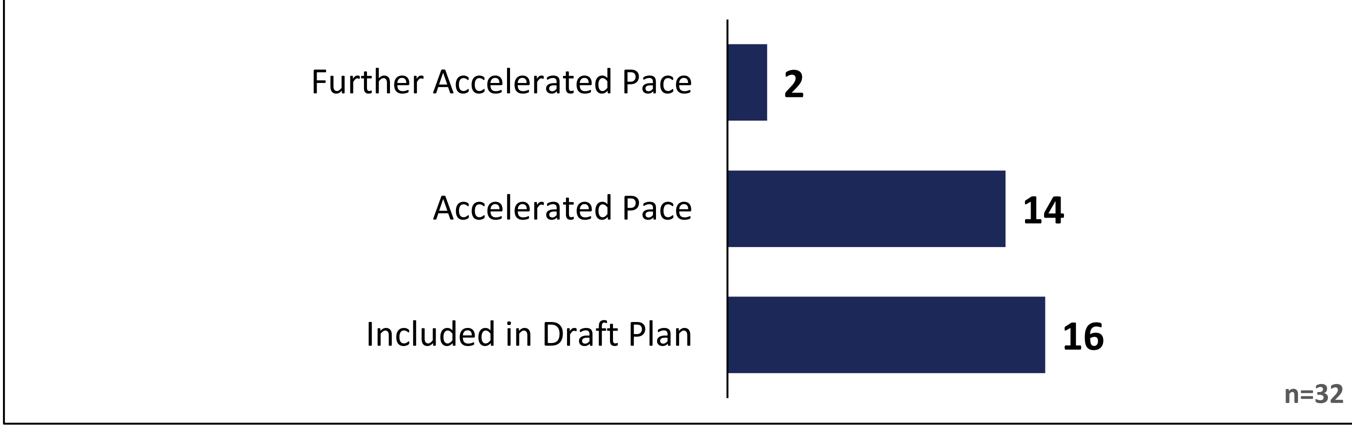
Q Which of the following options do you prefer?



Additional Feedback (n=2) Verbatim Responses 30/32 of respondents did not provide additional feedback
So you talking a 1 per month.
Same as pervious answer.

Representative Workbook

Background Information

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Making Choices (5 of 7)

Subdivision underground rehabilitation

71 of the subdivisions in NPEI's service territory were constructed with **direct buried cable** which refers to a type of construction where cables are laid directly in underground trenches without a protective barrier.

While this was typical construction at the time, 40 of these subdivisions were built 40 or more years ago, and the cables are now approaching the end of their recommended life.

In this upcoming plan, NPEI is proposing a new program to start preparing to upgrade the service in the subdivisions with the most pressing needs.

In order to keep costs down, NPEI is proposing to start rehabilitation of the underground "system" by installing ducts that will eventually carry underground cables over the next five years. The cables would be installed as needed (upon failure) or once all of the old subdivisions have had the duct installed.

Completing this work in two phases will not only save costs now, but also help ensure that NPEI will be able to rehabilitate the most subdivisions in the shortest time.

Between 2021 and 2025, NPEI is proposing a new program that will proactively install ducts in approximately 10 subdivisions. Which subdivisions receive investment first will predominantly be based on age. That said, there is an opportunity to either accelerate or slow down the pace of this new program.

Option	Km of vault installed	Expected Outcome
Accelerated Pace ***Additional*** *$0.48 per month annually ($5.76 more per year)*	30 km by 2025 (6 km per year)	Install 6 km of ducts or approximately four subdivisions per year.
Included in Draft Plan *Within proposed average 2.7% increase over 5-years*	15 km by 2025 (3 km per year)	Install 3 km of ducts or approximately two subdivisions per year.
Slower Pace ***Decrease*** *of $0.23 per month annually ($2.76 less per year)*	7.5 km by 2025 (1.5 km per year)	Install 1.5 km of ducts or approximately one subdivision per year.

Representative Workbook

Subdivision underground rehabilitation

Commercial
GS > 50 kW

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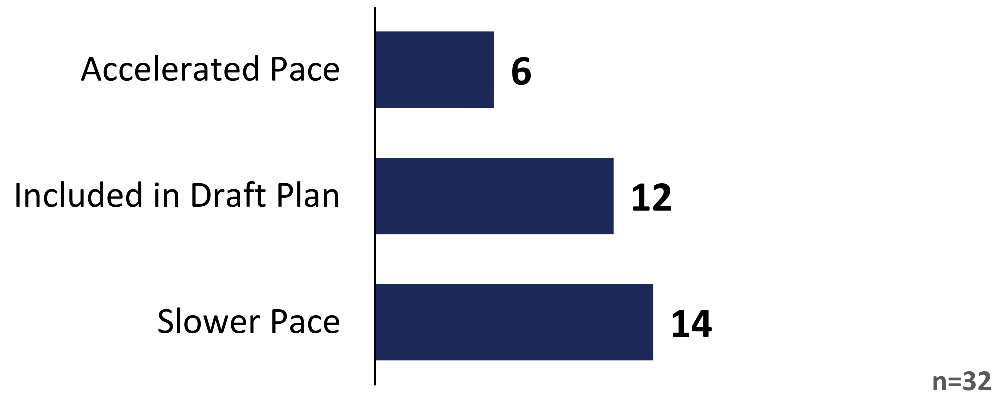
Q Which of the following options do you prefer?



Additional Feedback (n=2) Verbatim Responses
30/32 of respondents did not provide additional feedback

This should be costed out at beginning with the developer costs. They should bear the costs. Not charge enough upfront but should consider maintenance costs to sustain this service up to lifespan of the underground wiring. Why is NPEI barring these costs, factor this in the beginning of the costs to the developers as they make the money on the lots/houses sold.
Same as pervious answer.

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Making Choices (6 of 7)

Overhead rebuilds

Beyond replacing overhead poles, NPEI has a program that rebuilds the overhead system for entire streets and neighbourhoods. This includes poles, wires, and all other equipment that goes into operating the overhead system.

A recent asset health condition assessment identified a total of **60 areas** within NPEI's service territory that require complete overhead rebuilds**.** Most of this equipment is either beyond its recommended age or deteriorated due to weather and other factors. This infrastructure is in addition to the poles identified in the earlier section.

This program is intended to contribute to the "betterment" of the overhead system by;

- Improving system performance by installing animal guards and higher capacity transformers to reduce the likelihood of outages, and;
- Improving system aesthetics with new and taller poles.

On average, each of the projects would replace approximately 30-40 poles, depending on the population density of the area being worked on. NPEI's current approach would rebuild **40 out of 60 areas** in the 2021 to 2025 period.

NPEI must continue to invest in overhead rebuilds, therefore, this is a matter of whether customers would rather pay more during the upcoming period or push some level of investment beyond the next five years.

Option	Overhead rebuilds	Expected Outcome
Accelerated Pace ***Additional*** *$0.71 per month annually ($8.52 more per year)*	61 km by 2025 (12.2 km per year)	Rebuild 12.2 km per year or approximately 10 projects per year
Included in Draft Plan *Within proposed average 2.7% increase over 5-years*	48.5 km by 2025 (9.7 km per year)	Rebuild areas with assets that have been identified as very poor in Asset Condition Assessment. Rebuild 9.7 km per year or approximately 8 projects per year
Slower Pace ***Decrease*** *of $0.70 per month annually ($8.40 less per year)*	36 km by 2025 (7.2 km per year)	Rebuild 7.2 km per year or approximately 6 projects per year

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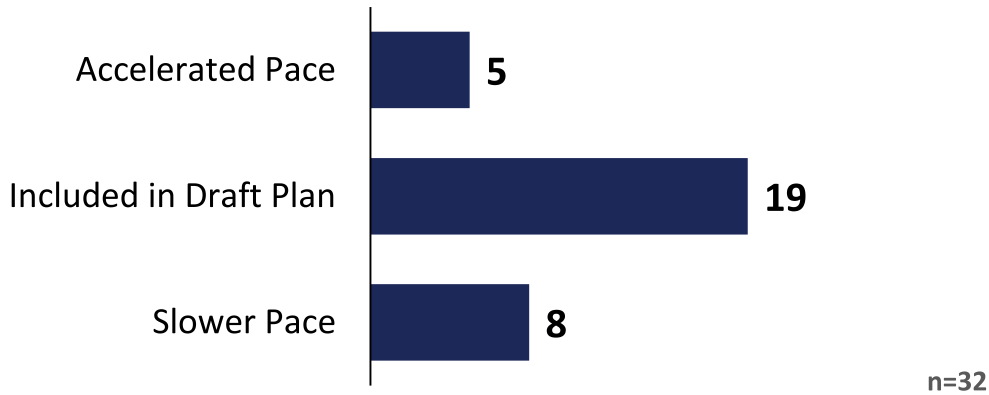
Representative Workbook

Overhead rebuilds

Commercial
GS > 50 kW

Q Which of the following options do you prefer?



Additional Feedback (n=2) Verbatim Responses 30/32 of respondents did not provide additional feedback
Need to invest in underground instead -yes poles cheaper but costs the customers more in the long run.
Same as pervious answer.
Underground?

Making Choices (7 of 7)

Grid modernization

New technology has changed the way that NPEI can manage and monitor the distribution system.

Supervisory Control and Data Acquisition (SCADA) systems allow NPEI staff the ability to remotely monitor and trace system faults and re-close switches from a control room rather than sending a repair crew to patrol the lines. These systems are particularly effective where there are larger distances between customers, for instance, in more rural areas of the western region of NPEI's service territory.

This equipment can have significant positive impacts on restoration times when an outage does occur, particularly in instances such as during a severe weather event.

On average, since 2014, NPEI has installing approximately two remote devices per year, with focus on more rural, lower density areas. That said, there is an opportunity to install this monitoring and control equipment more quickly or slowly.

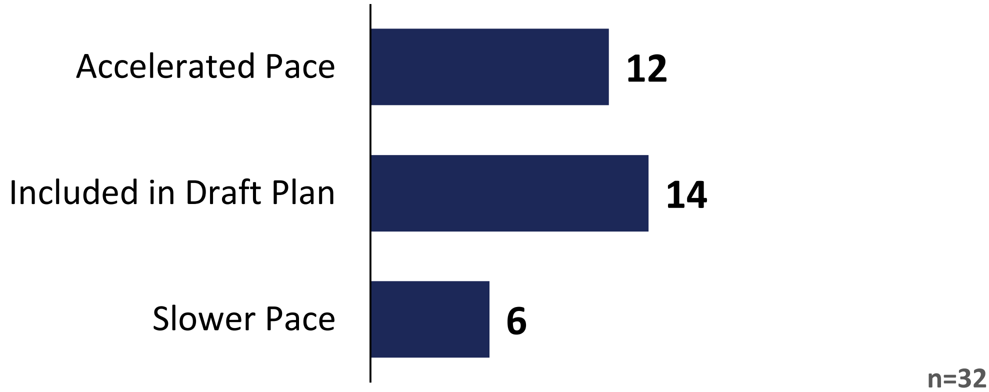
Option	**Devices installed**	**Expected Outcome**
Accelerated Pace ***Additional*** *$0.14 per month annually ($1.68 more per year)*	20 devices (4 per year)	NPEI to double installation rate to four devices per year.
Included in Draft Plan *Within proposed average 2.7% increase over 5-years*	10 Devices (2 per year)	Remain at current installation pace of two devices per year. Install new devices to expand NPEI's Smart Grid network. These devices provide better monitoring capability on the system, which leads to improved restoration times during outages.
Slower Pace ***Decrease*** *of $0.06 per month annually ($0.72 less per year)*	5 Devices (1 per year)	NPEI to cut rate of installation in half to one device per year.

Representative Workbook

Grid modernization

Commercial
GS > 50 kW

Q Which of the following options do you prefer?



Additional Feedback (n=1) Verbatim Responses
31/32 of respondents did not provide additional feedback

Need to get with the times, we want our local hydro to be our facilitator for our energy needs now and for the future. Private sector will be too expensive for businesses. OEB as the regulator should realize this as it is key for business to go through their hydro as we know they will not gauge us and know our business and assist us.

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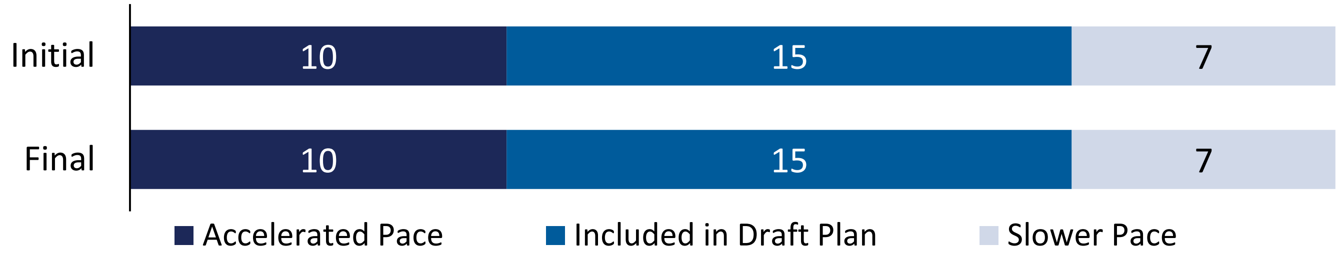
Representative Workbook

Change in Initial vs. Final Response by Project

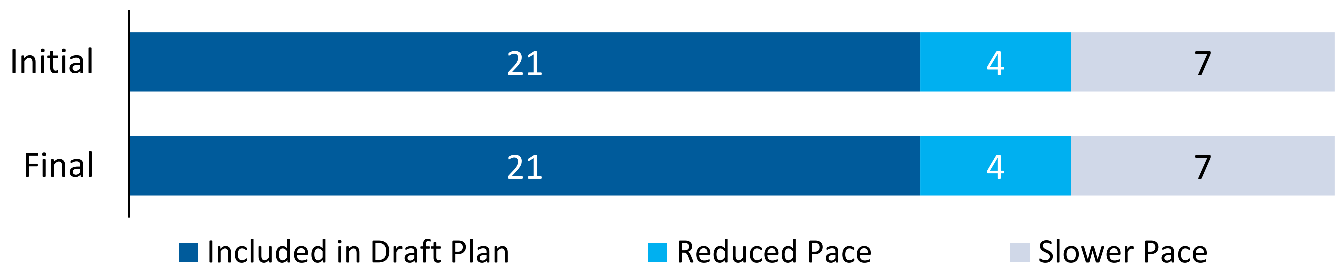
Commercial
GS > 50 kW

Q Overhead Pole Replacement

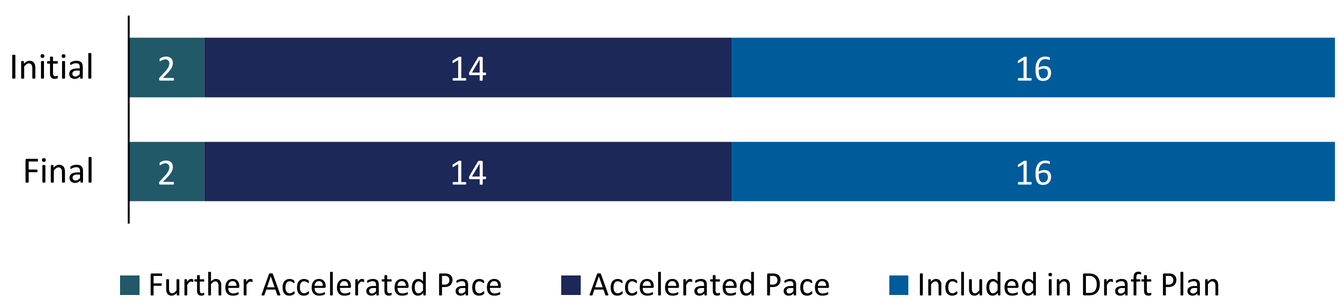


Q Overhead Transformer Replacement

Q Converting Outdated Underground Kiosk Transformers



Q Underground Cable Replacement



Representative Workbook

Change in Initial vs. Final Response by Project

Commercial
GS > 50 kW

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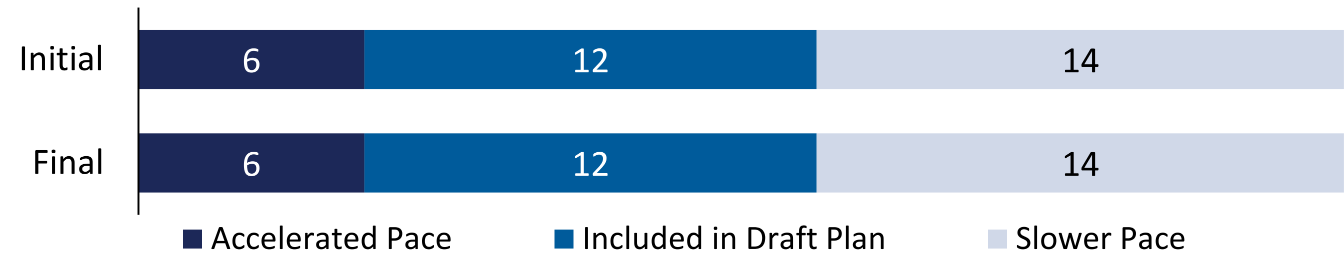
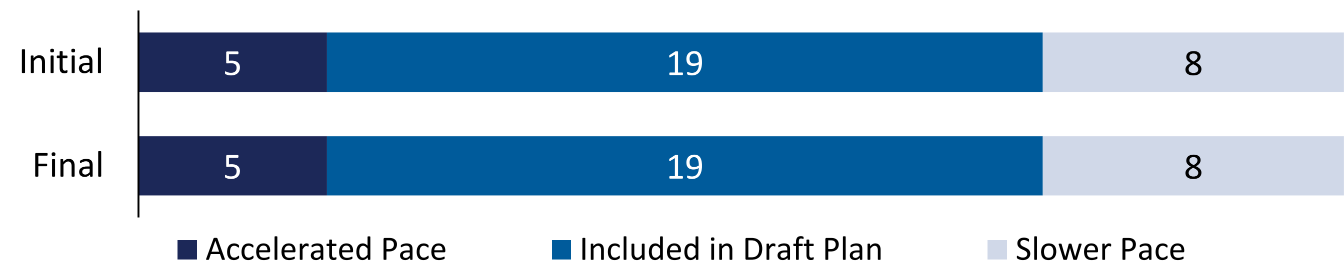
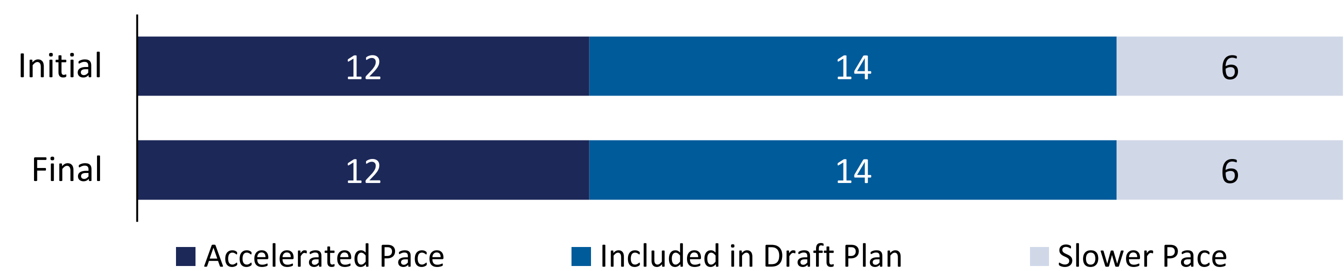
Q Subdivision Underground Rehabilitation



Q Overhead Rebuilds



Q Grid Modernization



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Impact of Choices

Assessing Niagara Peninsula Energy's draft 2021-2025 plan

Again, it is estimated that if NPEI continues with its preliminary plan, the distribution portion of the bill will increase by $65.65 per month in 2021, when the plan is set to come into effect. For the period 2022-2025, the annual bill increase is limited by the OEB to be less than the rate of inflation.

- At the end of the 5-year plan, the typical mid-sized business customer would see the distribution portion of their electricity bill increase by $105.39.
- As a result, the distribution charges on the typical mid-sized business customer's monthly bill would increase from $747.52 in 2020 to $852.91 by 2025.

Estimated Typical Mid-Sized Business Annual Increase in Monthly Bill (5 year forecast)

	Year	Average Mid-Sized Business Bill	Distribution Portion of Bill	Incremental Rate Change	% Change * (on distribution portion of bill)
Current Rate	**2019**	$11,661.27	$738.65		
Budgeted Rate	**2020**	$11,876.06	$747.52	$8.87	1.20%
Forecast for next rate period	**2021**	$11,948.38	$813.17	$65.65	8.78%
	2022	$12,127.61	$822.92	$9.76	1.20%
	2023	$12,309.52	$832.80	$9.88	1.20%
	2024	$12,494.17	$842.79	$9.99	1.20%
	2025	$12,681.58	$852.91	$10.11	1.20%
				$105.39	

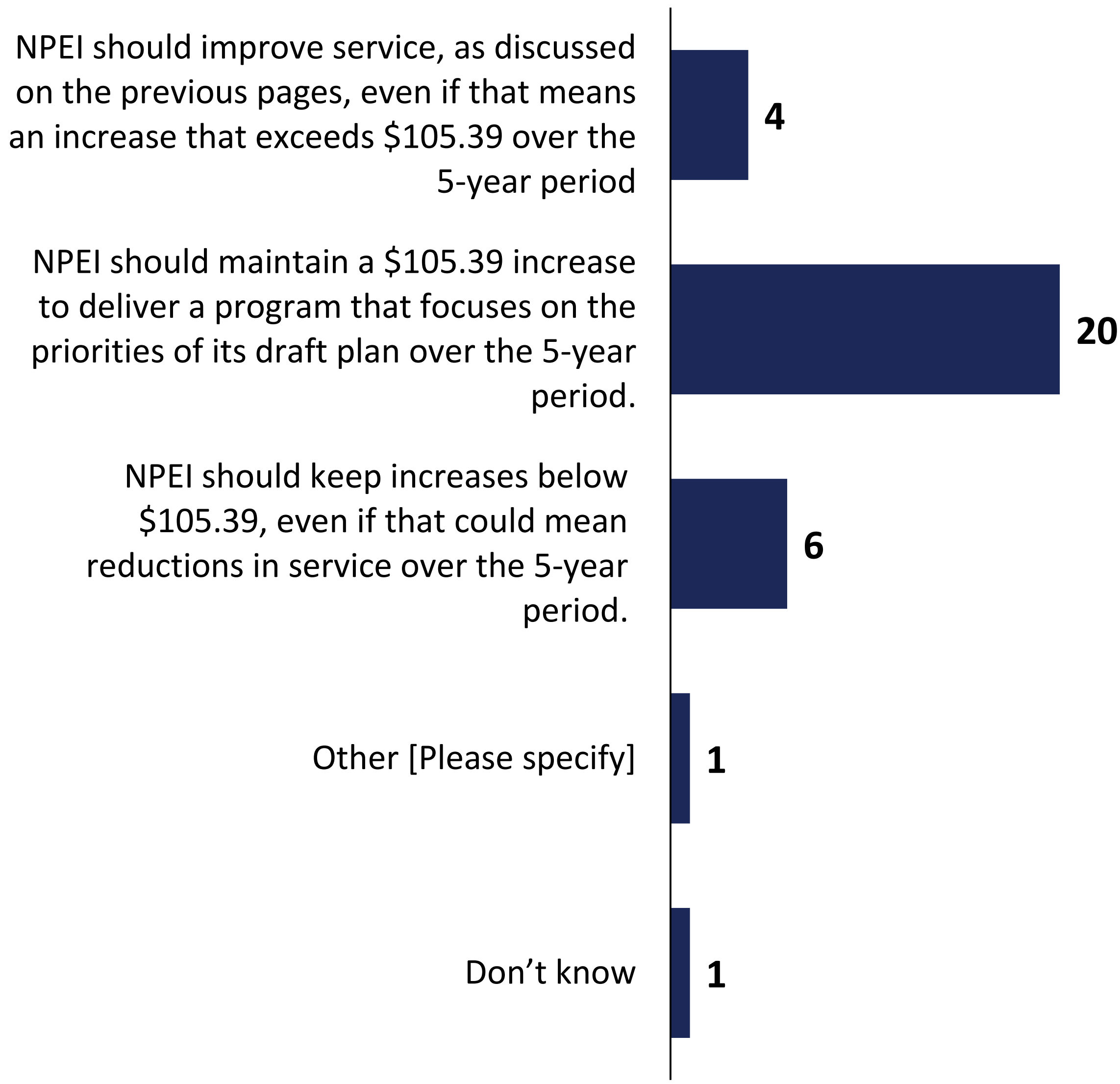
*** These estimates are preliminary, and are subject to your feedback as the business plan is finalized .**

Representative Workbook

Assessing Niagara Peninsula Energy's draft 2021-2025 plan

Commercial
GS > 50 kW

Q Considering what you know about Niagara Peninsula Energy's draft plan – which would see the typical mid-sized business customer's distribution portion of their bill increase by $105.39 over the 5-year period – which of the following best represents your point of view?



n=32

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Representative Workbook

Final Comments

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Q Thinking about your answer to the previous question, why do you feel that NPEI should take that approach over the 2021-2025 period?

Final Thoughts (n=8) Verbatim Responses 24/32 of respondents did not provide additional feedback
There is not cap it just says an increase that exceeds, too vague a statement. How much more? A moderate increase would be acceptable.
NPEI should carefully pace increases in rates to avoid excessive cost burden to businesses.
NPE is a business just like my business owning apartment buildings. You spend the money your comfortable with and increase what you need to do such work but keep in mind your business also has to spend money and not just your customers.
Might as well bite the bullet now, it should save us money in the long run. Electricity is part of the lifeline of our local economy and therefore we should keep the grid in good condition. As a business owner I experience from close by what the direct but also the indirect cost to my business when a power outage occurs.
Maximize existing infrastructure to it's fullest potential. If it ain't broke, don't fix it.
Leverage Technology to communicate with customers, customers expectations have change over the years with "SMART" tech, phones, appliances, LED, Battery Storage etc.. But the regulator doesn't provide the hydro to move with the times and facilitate this for us. I trust my local utility over private sector which have NO OVERSIGHT and would gauge the businesses. Offer conservation programs to the businesses and educational opportunities to maintain our electricity costs in order that we can sustain our businesses.
It seems like the best approach with the least negative impact to the customer
Deferring investment is likely more costly in the long-run.

Q Do you have any final comments regarding NPEI or the customer engagement that you just completed?

Final Thoughts (n=3) Verbatim Responses 29/32 of respondents did not provide additional feedback
Dedicated conservation managers who assist businesses with energy savings and incentives (ERIP, EBCx projects, Global Adjustment Class reviews, etc.) are a valuable asset and vital to business goals in managing energy costs.
NPEI is a local utility that gives back to the communities and when I call they answer the questions, when we were involved with the conservation programs, a representative from the Utility came out and assisted us the applications and educated us and so customer engagement should done on an ongoing basis NOT every 5 years when the OEB funds it though this RATE Process you indicated. This is too long of a survey, do it more often.
Very beneficial and upfront.

Representative Workbook

Background Information

Designing Rates

Potential changes to fixed versus variable distribution rates

In recent conversations with mid-sized and large business customers, the topic of cost certainty regarding distribution rates has been raised.

Currently, distribution rates for customers, like yourself, are based on a 15% fixed and 85% variable rate. This means that 85% of your distribution charges are largely based on how much electricity you use.

In order to improve cost certainty, some customers have expressed a desire to move to a more fixed distribution rate. In its current draft plan, NPEI is proposing to increase the fixed portion of the distribution charge to 21%. Not only does this create more cost certainty for customers, but it also provides revenue certainty for NPEI to operate and maintain the distribution system

For customers who have predictable electricity usage habits, this change likely wouldn't have much of an impact, while creating more certainty for those whose electricity usage fluctuates more regularly.

NPEI is looking to understand what fixed-variable split you would like to see the utility use over the next 5-years and beyond.

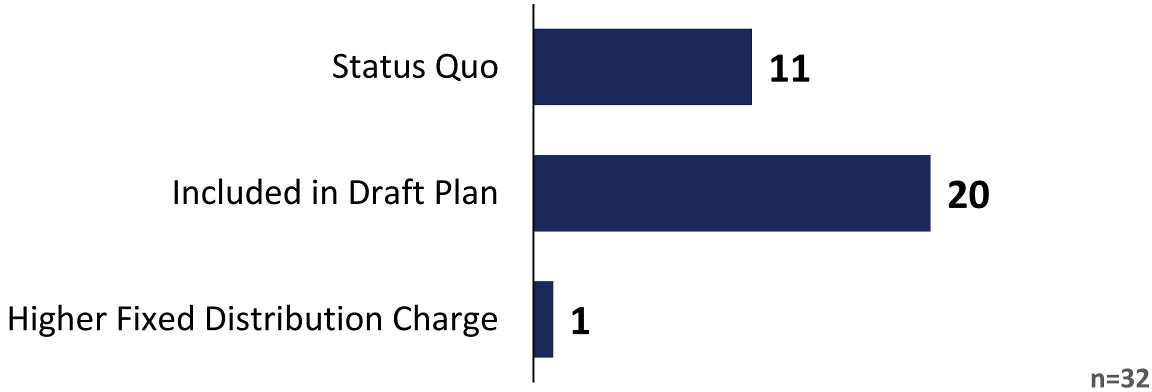
Option	**Fixed-Variable Split**	**Expected Fixed Versus Variable Charge**
Status Quo	15% fixed; 85% variable	Total distribution charge for a typical mid-sized business customer would be $813.37 in 2021 • $118.75 fixed monthly distribution charge • $3.86 per kW variable charge
Included in Draft Plan	21% fixed; 79% variable	Total distribution charge for a typical mid-sized business customer would be $813.17 in 2021 • $161.17 fixed monthly distribution charge • $3.62 per kW variable charge
Higher Fixed Distribution Charge	33% fixed; 66% variable	Total distribution charge for a typical mid-sized business customer would be $813.56 in 2021 • $256.15 fixed monthly distribution charge • $3.10 per kW variable charge

Representative Workbook

Potential changes to fixed versus variable distribution rates

Commercial
GS > 50 kW

Q Which of the following options do you prefer?



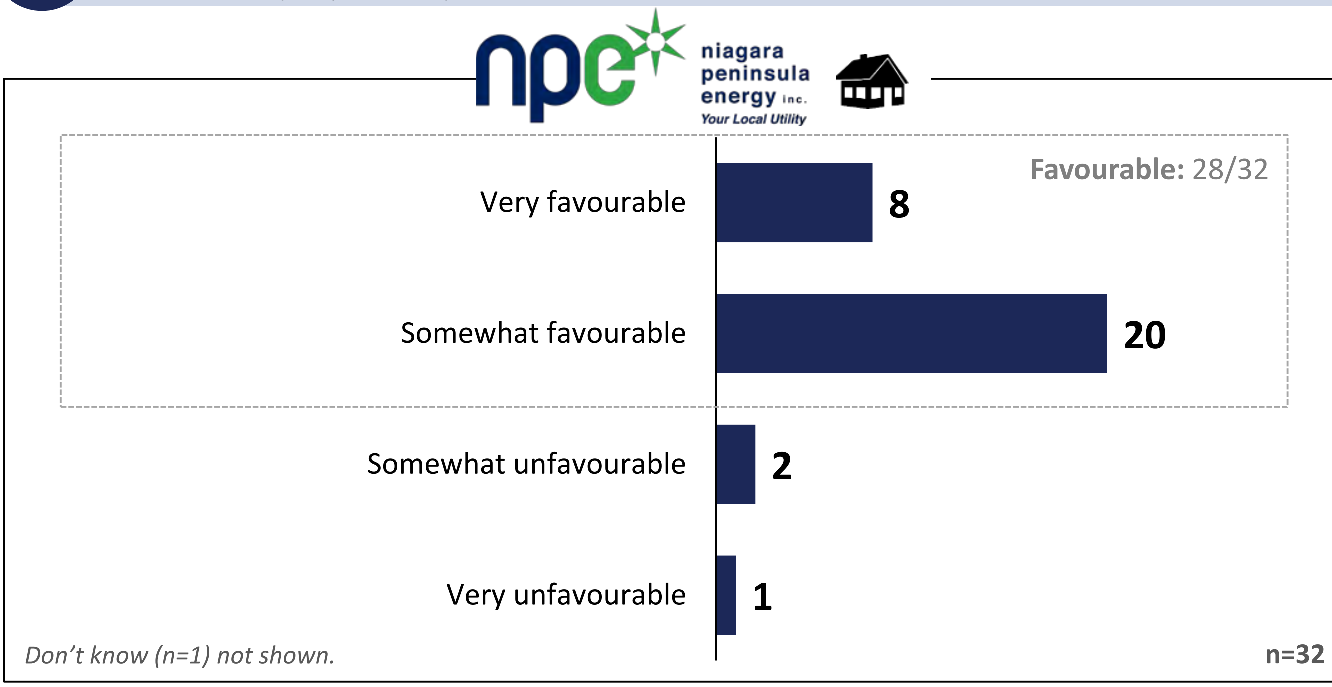
Final Thoughts (n=3) Verbatim Responses 29/32 of respondents did not provide additional feedback
Higher fixed rate would impact the payback as we invest in electricity saving technology and initiatives.
I do not really like any of the options provided and cannot make any recommendations as I believe an audit is required of the NPE bills to see if 6% as estimated in correct.
The higher the fixed rate, the less incentive there is to conserve.

Representative Workbook

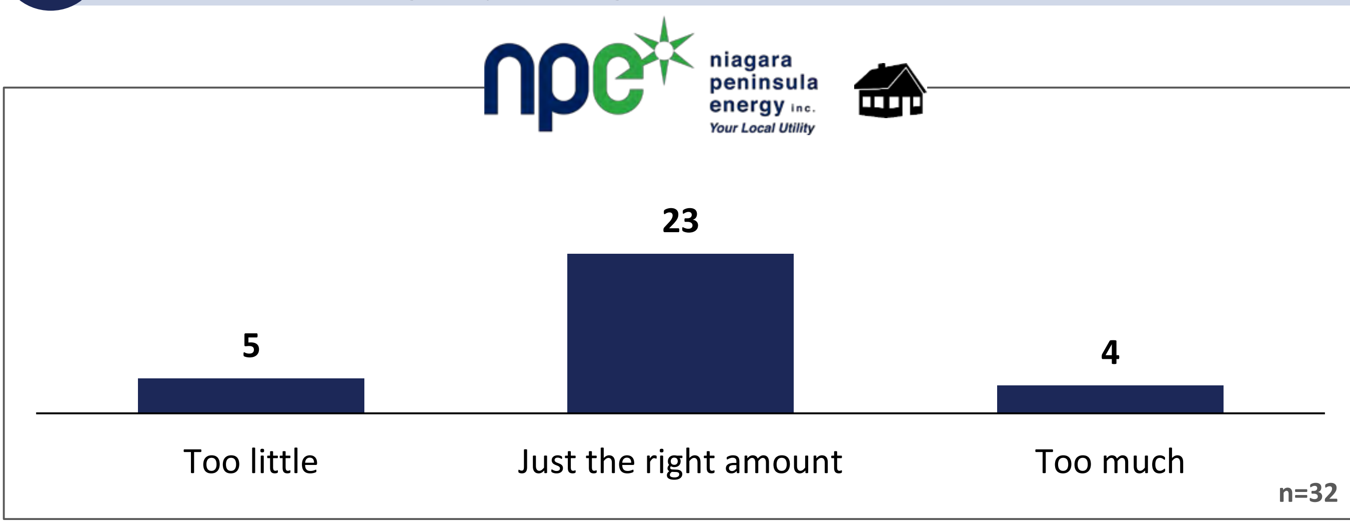
Final Thoughts: Workbook Diagnostics

Commercial
GS > 50 kW

Q **Overall Impression**: Overall, did you have a favourable or unfavourable impression of the consultation you just completed?



Q **Volume of Information:** In this consultation, do you feel that NPEI provided too much information, not enough, or just the right amount?



Representative Workbook

Content Covered

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Q Was there any content missing that you would have liked to have seen included in this consultation?

Final Thoughts (n=4) Verbatim Responses 28/32 of respondents did not provide additional feedback
A number or contact at NPE to discuss the 6% charge which seems quite erroneous
Any incentive program for the customer side to lighten the load on the NPEI side.
Difficult to give an opinion on expenses without the whole picture.
Information on "Save on Energy" Programs

Q Is there anything that you would still like answered?

Final Thoughts (n=3) Verbatim Responses 29/32 of respondents did not provide additional feedback
Please tell me why there are employees and management making over $150000 a year working in public utilities .
How did NPE come up with 6%, what is the highest percentage and the lowest percentage... is 6% an average? our bills in 2018 it was 36% with the global adjustment being around the same %.... your math does not seem right.
As part of above, is it possible that we can get a brake on the monthly load factor or delivery charge if our company invest in technology or equipment to help out NPEI by partially going off the grid as needed.

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Building Understanding.

Personalized research to connect you and your audiences.

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Appendix 6.0

INNOVATIVE
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2021-2025 Rate Application

Voluntary Report

npe niagara peninsula energy inc.
Your Local Utility

January 2020

STRICTLY PRIVILEGED AND CONFIDENTIAL

Voluntary Workbook

Survey Design & Methodology

INNOVATIVE was engaged by NPEI to gather input on preferences on program timing and balancing outcomes. **Pages 3 to 44** show the actual pages of the workbook completed by customers (for illustration, the residential version has been used. Refer to the Representative Report for the small business version). The only additions are the actual results.

Field Dates & Workbook Delivery

The **Voluntary Online Workbook** was accessible to all Niagara Peninsula Energy residential and small business customers between **December 2nd and December 17th, 2019**.

INNOVATIVE hosted the online portal at *NPEICustomerEngagement.ca*.

NPEI promoted the voluntary workbook via their website and social media.

The website saved their progress as they answered each question, thus preventing customers from completing questions repeatedly. Upon completion, the site was no longer accessible at the web address given. Each customer was able to select their rate class, ultimately providing them with a workbook customised for whether they were a residential or small business customer.

Voluntary Online Workbook Completes

A total of **133** (unweighted) NPEI residential and small business customers completed the voluntary online workbook via the generic website link. Due to the small number of NPEI small business customers who completed the voluntary workbook, results from both rate classes have been combined for analysis purposes.

The voluntary online workbook sample has not been weighted, therefore, is not representative of the broader NPEI customer base.

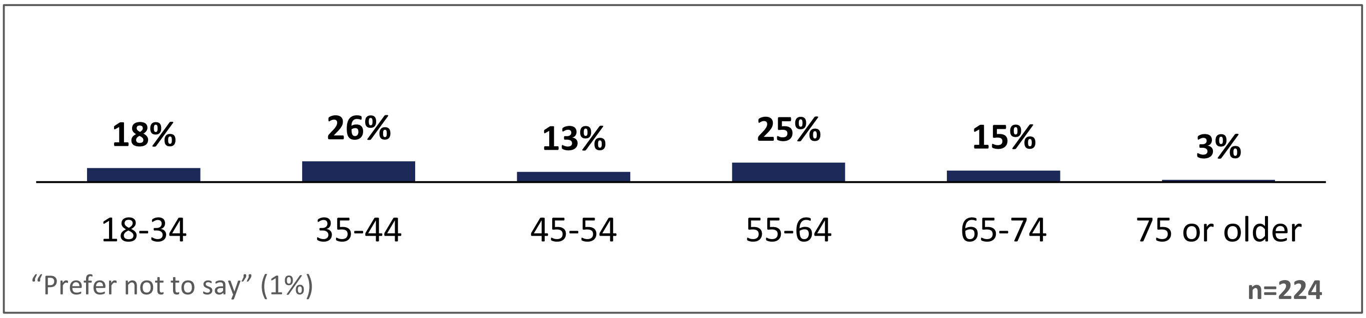
Unweighted Sample	Completes	Workbook Distribution
Residential	224	**96%**
Small Business	9	**4%**
Total	**233**	**100%**

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

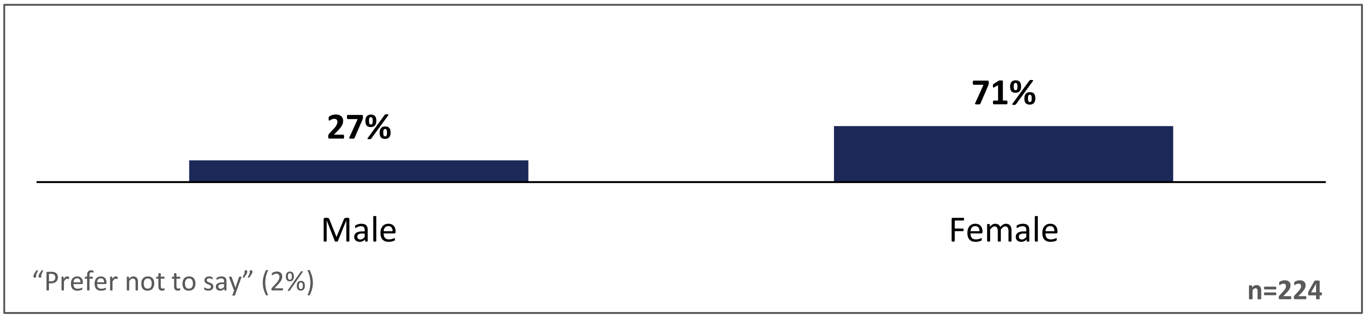
Voluntary Workbook

Demographic Breakdown

Q **Age** (Residential Only)



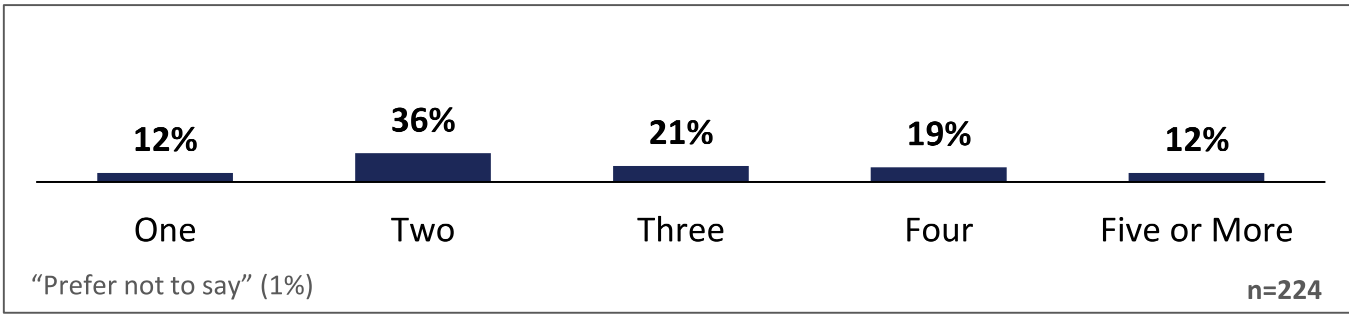
Q **Gender** (Residential Only)



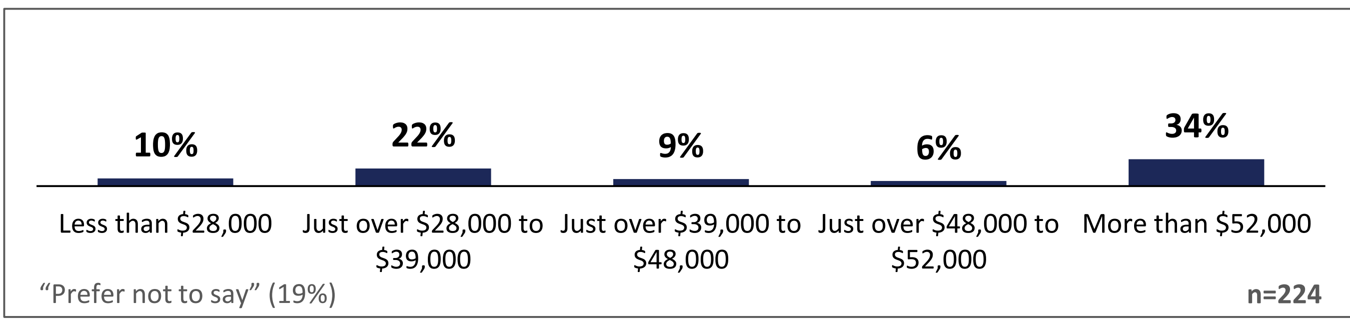
Voluntary Workbook
Demographic Breakdown

Residential & Small Business

Q Household Size (Residential Only)

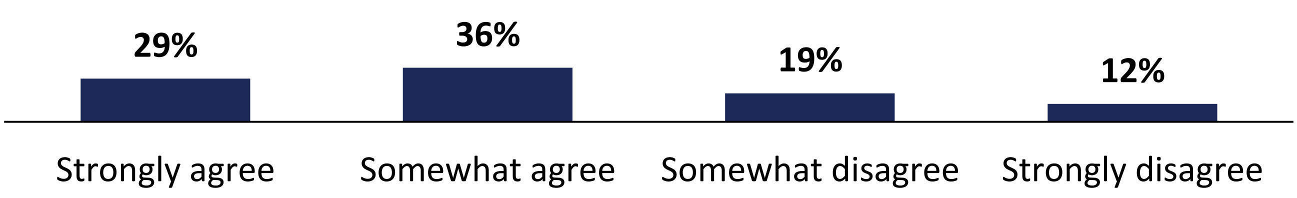


Q After Tax Household Income (Residential Only)



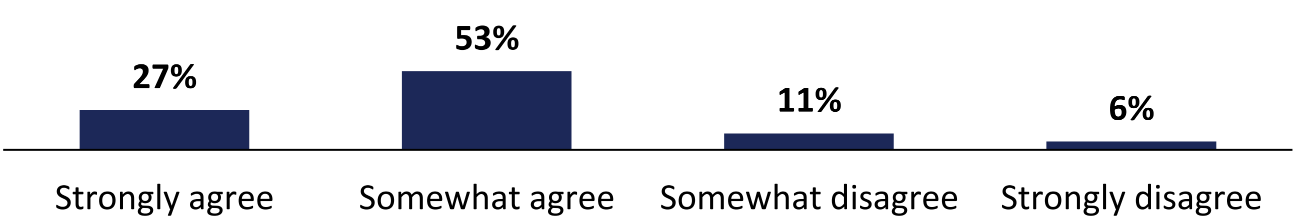
Thinking generally about the electricity system in Ontario, including generation, transmission and local distribution, do you agree or disagree with the following statements?

Q The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.



"Don't know" (3%) not shown. n=233

Q Customers are well served by the electricity system in Ontario.



"Don't know" (3%) not shown. n=233

About this Consultation

Welcome to Niagara Peninsula Energy's Customer Engagement!

Niagara Peninsula Energy (NPEI) needs your input on choices that will impact the services you receive and the rates that you pay.

- **NPEI** is developing its investment plan for 2021 to 2025. This plan will determine the investments NPEI will make in equipment and infrastructure; the services it provides; and the rates you pay.
- As **NPEI** plans for the future, they want to ensure their business decisions are aligned with customers priorities, preferences, and needs.
- Throughout this survey, information will be provided in an effort to give you more background on which to base your responses.
- While responding to the following questions, remember that there are no wrong answers, and that your individual responses will remain anonymous.
- This customer engagement will take approximately 25-35 minutes to complete, depending on the level of feedback you wish to provide. Your progress will be saved as you move through the workbook, meaning you can leave and return to the customer engagement at any time.

All individual responses will be kept confidential. Innovative Research Group (INNOVATIVE), an independent research company, has been hired NPEI to gather your feedback.

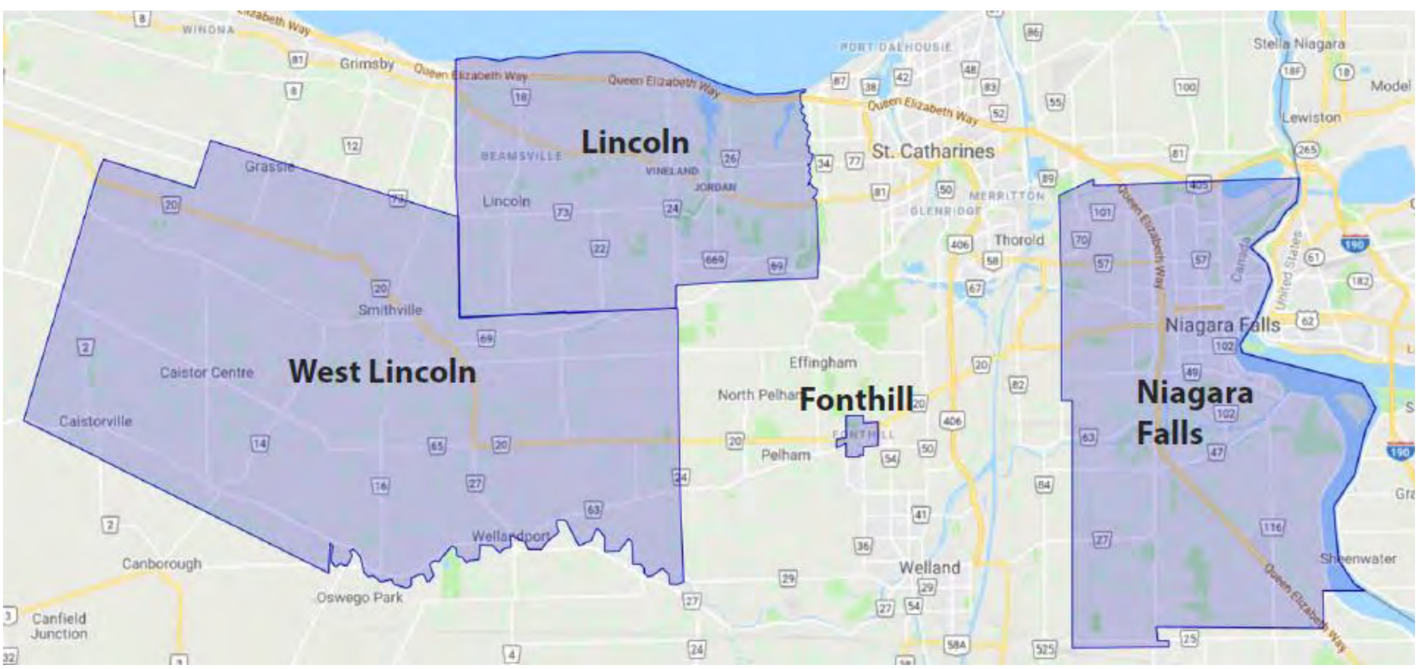
Those who complete the questions that follow will be invited to enter a draw to win one (1) $500 cash prize.

Electricity 101

Who is Niagara Peninsula Energy?

NPEI provides local electricity distribution and related services to residential and business customers in the City of Niagara Falls, Town of Lincoln, Town of Pelham, and Township of West Lincoln.

- NPEI serves an area of approximately 827 square kilometers and 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 local distribution company (LDC) and regulated entity, NPEI applies for, and receives approval from the regulator to charge for its services.



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Electricity 101

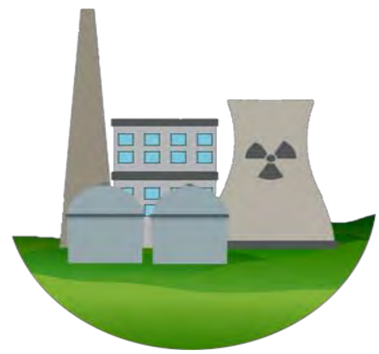
Niagara Peninsula Energy's Role in Ontario's Electricity System

Ontario's electricity system is owned and operated by public, private, and municipal corporations across the province. It is made up of three key components: **generation**, **transmission** and **distribution**.

Generation

Where electricity comes from

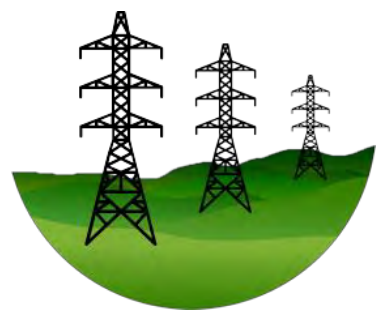
Ontario's electricity is generated using a mix of nuclear, gas-fired, and water power (hydro), as well as biomass and renewable sources such as wind and solar technology. In Ontario, a number of companies own these generating stations but approximately half of the electricity is generated by Ontario 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.



Transmission

How electricity travels across Ontario

Once generated, electricity must be transported to electrical substations 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 kilometres of 'electricity highway', most of which is owned and operated by Hydro One.



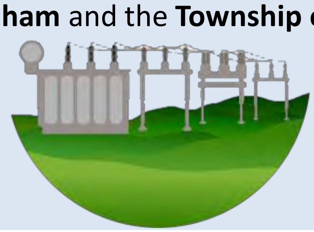
Local Distribution

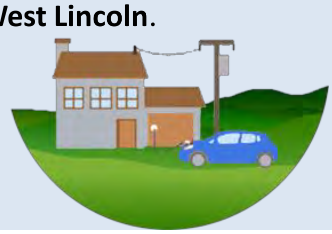
How electricity is delivered to the end-consumer

NPEI is responsible for the last step of the journey: distributing electricity to customers through its distribution system. This local distribution system includes transformer stations that decrease the voltage of the electricity so it can be used safely in your home or business.

There are approximately 1,451 km of overhead power lines and 573 km of underground cable. Through this distribution network, NPEI delivers electricity to approximately 55,600 residential and business customers.

Niagara Peninsula Energy Inc. is jointly owned by the **City of Niagara Falls**, the **Town of Lincoln**, the **Town of Pelham** and the **Township of West Lincoln**.





npe niagara peninsula energy Inc.
Your Local Utility

Voluntary Workbook

Familiarity with Ontario's electricity system

Residential & Small Business

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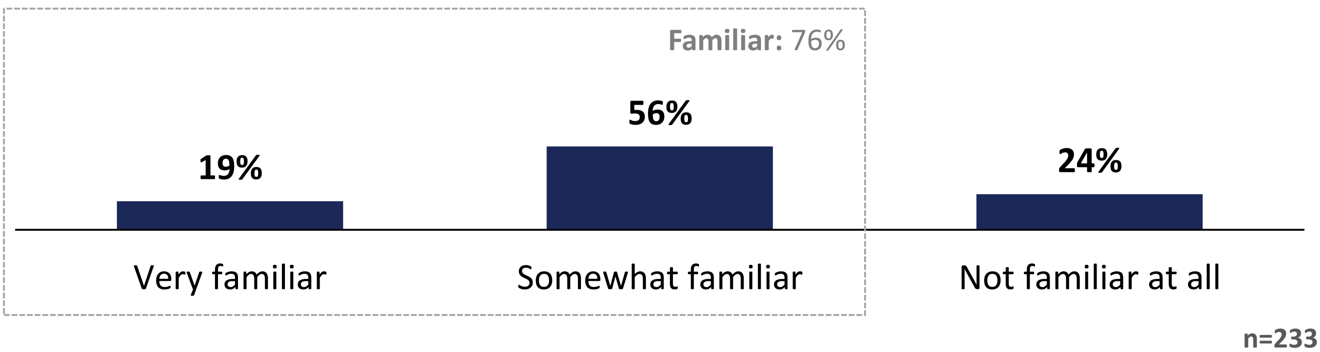
Q Before this survey, how familiar were you with Niagara Peninsula Energy, which operates the electricity distribution system in your community?

niagara peninsula energy inc.
Your Local Utility



Voluntary Workbook
Background Information

Residential & Small Business

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Electricity 101

How much of my electricity bill goes to Niagara Peninsula Energy?

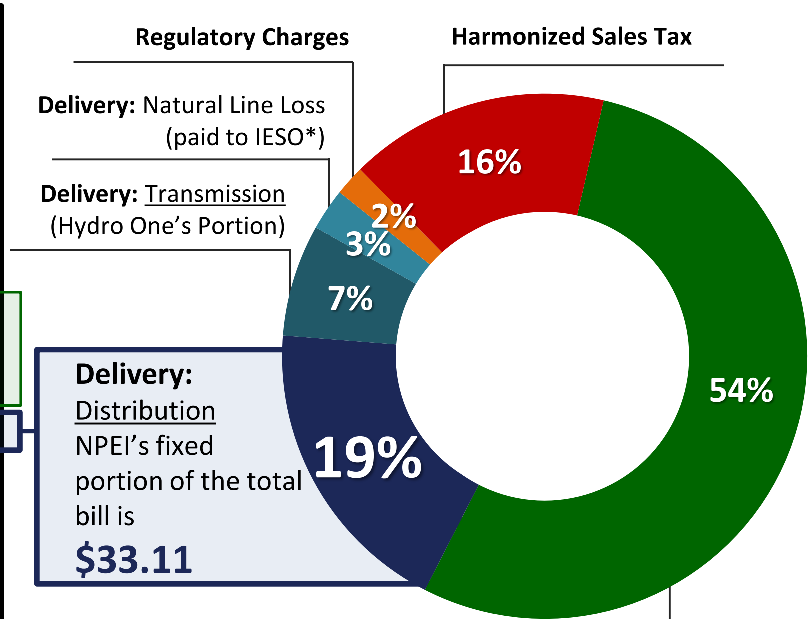
- Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board (OEB), the provincial energy regulator.
- While NPEI is responsible for collecting payment for the entire electricity bill, it retains only the distribution portion of the delivery charge.
- Distribution makes up about **19%** of the typical residential customer's bill.
- For residential customers, NPEI's portion of the delivery line on the bill is fixed and does not change based on the amount of electricity you use.
- The rest of your bill is passed onto provincial transmission companies, power generation companies, the government and regulatory agencies.

NPEI Sample Monthly Bill*
(Based on monthly usage of 700 kWh)

Account Number:
000 000 000 000 0000

Meter Number:
00000000

Your Electricity Charges	
Electricity	
Off-Peak @ 10.1 ¢/kWh	**45.25**
Mid-Peak @ 14.4 ¢/kWh	**18.14**
On-Peak @ 20.8 ¢/kWh	**26.21**
Delivery	**46.85**
Regulatory Charges	**3.11**
Total Electricity Charges	**$139.56**
HST	**18.14**
Ontario Electricity Rebate*	**(-$44.38)**
Total Amount	**$113.32**



*IESO = Independent Electricity System Operator

* As of November 1, 2019. Chart is based on total bill amount after applying the Ontario Electricity Rebate.

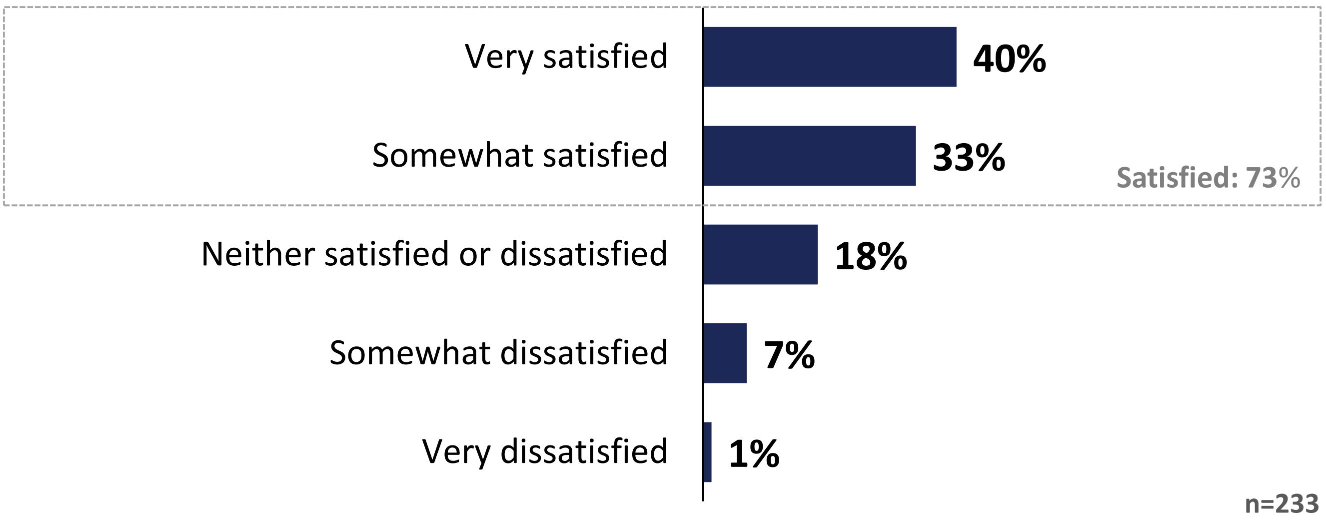
INNOVATIVE RESEARCH GROUP

Voluntary Workbook

Overall Satisfaction with Niagara Peninsula Energy

Residential & Small Business

Q Thinking specifically about the services provided to you and your community by Niagara Peninsula Energy, overall, how satisfied or dissatisfied are you with the services that you receive?



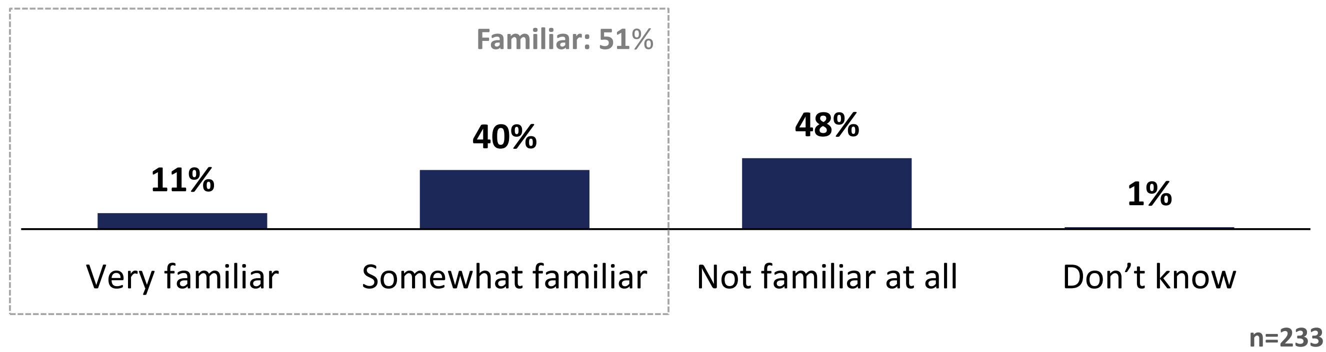
Voluntary Workbook

Familiarity with Percentage if Bill Remitted to NPEI

Residential & Small Business

Q Before this survey, how familiar were you with the amount of your electricity bill that went to Niagara Peninsula Energy?

niagara peninsula energy inc. Your Local Utility



Q Is there anything in particular you would like Niagara Peninsula Energy to do to improve its services to you?

Improving Services (n=84) 64% of respondents did not provide additional feedback	**%**
Lower rates/Charge less	21%
No issues/satisfied with service/keep up the good work	13%
Offer rebates/assistance for low income/seniors	6%
Improve outage communication	5%
Improve customer service/meter reading	5%
Do not increase rates/keep rates affordable	4%
Find internal efficiencies/provide info on cost cutting	4%
Improve reliability/less outages	2%
Decrease/eliminate delivery charges	2%
Improve billing - clarity/payment terms/methods/website	2%
Maintain lines/improve tree clearing	2%
Modify time of use/peak rates	2%
Provide more info on energy consumption/conservation/renewables	2%
None	26%
Don't Know	2%

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Niagara Peninsula Energy Background

Building Niagara Peninsula Energy's draft plan

NPEI has put together its draft business plan based on the information and input from various sources, such as:

- **Legal and regulatory** requirements by continuing to meet its obligations.
- **Internal business planning** based on expert analysis and professional judgment to develop construction and operations programs that address safety, business, technical, and operational needs.
- **Customer feedback** collected through both ongoing dialogues and specific engagements, such as this.

There are three key organizations responsible for setting the policy direction of Ontario's electricity system. The decisions made by these organizations impact how utilities operate their businesses and serve their customers.

- **Policy**: The Ontario Ministry of Energy, Northern Development and Mines (MNDM) creates energy policy for the province.
- **Regulation**: The electricity industry in Ontario is regulated by the Ontario Energy Board (OEB). One of the OEB's roles is to review the business and distribution plans of all electricity distributors and approve the rates that they charge customers.
- **Operations and Planning**: The Independent Electricity System Operator (IESO) manages the provincial electricity grid, plans for the province's future energy needs, and develops conservation programs.

Ontario ENERGY /ÉNERGIE

ONTARIO ENERGY BOARD

ieso Connecting Today. Powering Tomorrow.

Niagara Peninsula Energy Background

How did customer feedback shape Niagara Peninsula Energy's draft plan?

NPEI is placing more emphasis on incorporating customer feedback into the planning process than ever before.

NPEI engages with its customers both in day-to-day interactions and in a variety of customer engagement activities. These interactions help identify customer needs and preferences, and inform how the utility plans for the future.

This past summer, NPEI engaged with **thousands of residential and business customers** from across its service territory – both in person and through telephone and online surveys.

What did NPEI hear from customers like yourself?

1. The clear majority of NPEI residential and small business customers are satisfied with the current service they receive. When asked how NPEI can improve service, top responses for residential customers were "nothing", followed by "lower or reduce rates".

2. Among competing outcomes, **price**, **reliability**, and **finding internal cost efficiencies** are the top three priorities for both residential and small business customers.

3. While keeping price at a reasonable and affordable level is an important priority, many customers feel that investing in the grid to maintain reliability, is preferable to deferring investments to keep bills low.

Considering this feedback, as well as the information and inputs discussed on the previous page, NPEI has developed a draft plan that is responsive to:

1. Legal requirements by continuing to meet its obligations, including safety and reliability;

2. A transformer station upgrade to accommodate the new Niagara South Hospital and future surrounding growth.

3. Mandatory service connections to accommodate new customers and customer-required upgrades, of which NPEI does not have control over how and when these costs are incurred.

4. Customer feedback by:

    a) Keeping distribution price increases as low as possible;

    b) Maintaining long-term performance for customers experiencing average or better service;

    c) Improving service levels for customers experiencing below average service or who have special reliability needs (e.g. hospitals); and,

    d) Balancing other customer priorities (e.g. customer service) with the need to contain rate increases.

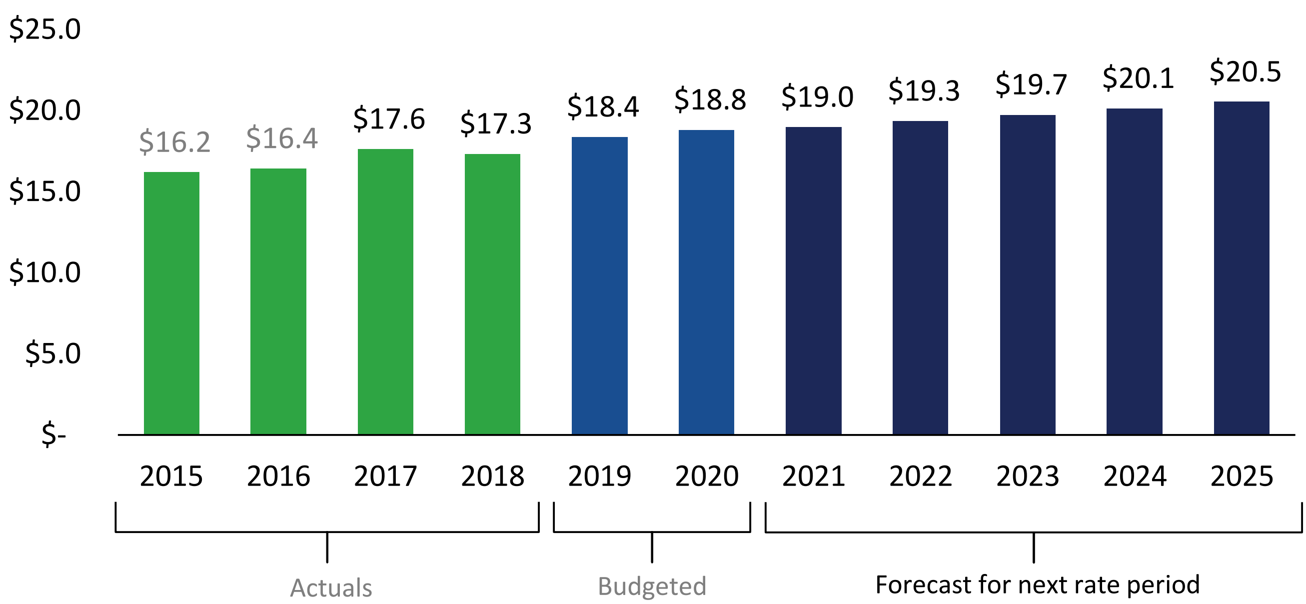
Niagara Peninsula Energy Background

Operating Expenses

In this section, we want to focus on operating expenses and how NPEI compares to its peers.

NPEI's operating budget covers recurring expenses, such as the maintenance of poles, wires, transformers, fleet and buildings as well as proactive maintenance programs such as tree trimming, and payroll for employees. Meter reading, postage, cyber security and hardware/software maintenance expenses are billing and customer service-related expenses. The proposed 5-year plan, between 2021 and 2025, would see NPEI spend an estimated total of $98.7 million on operations.

NPEI's Current and Forecasted Operating Expenses, per Year (Millions)*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

NPEI's **operating costs** are benchmarked by the OEB against other utilities in Ontario. In the last year of publicly available data collected by the OEB, NPEI's operating costs per customer was **$311.67**, which is slightly more than some, while less than both Hydro One and Canadian Niagara Power.

2018 Operating & Maintenance and Administration (OM&A) Per Customer ($)

The diverse geographical nature of NPEI's service territory, which is a mix of urban and rural communities is a large consideration/driver of these OM&A costs. In some parts of the service territory, there may be less than 30 customers per kilometer of line. Despite low density, these lines still require the same level of ongoing maintenance, including tree trimming and other expenses that contribute to operating the system; thereby resulting in a higher cost per customer.

Niagara Peninsula Energy Background

Operating Expenses

Recall, this customer feedback portal does not ask questions that expect you to be an electricity expert.

The OEB runs an open and transparent review process where experts from the OEB and intervenor groups review and challenge NPEI's analyses and assessments. You are welcome to participate in the OEB process if you are interested in those issues. Details can be found at oeb.ca/participate.

This customer engagement however, is focused on capital investments.

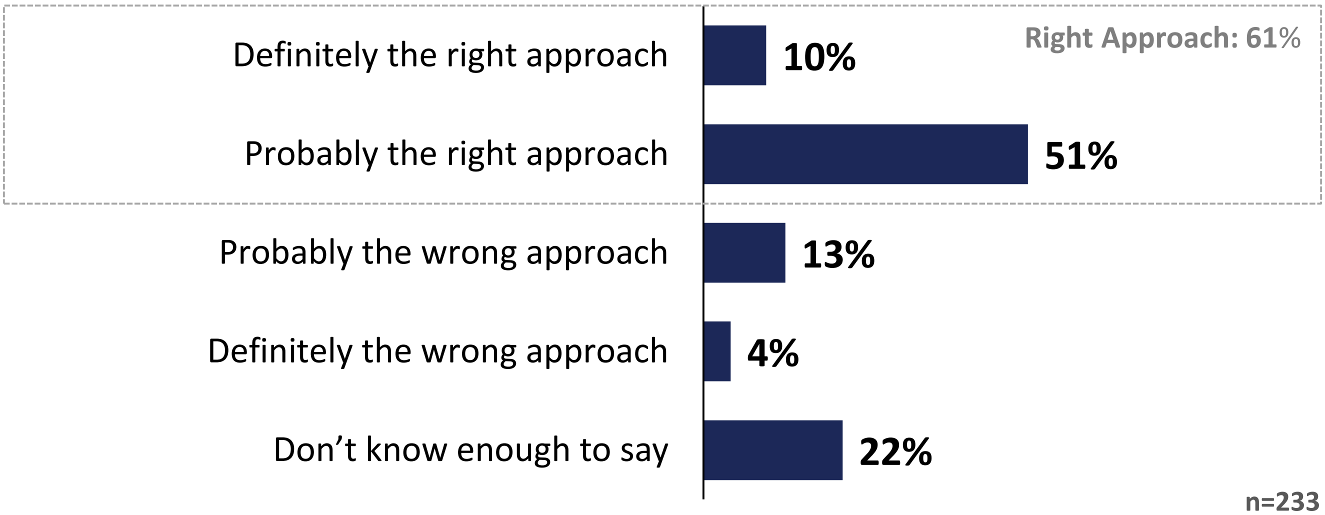
Detailed discussion of NPEI's operating budget is left to experts from the OEB and intervenors in the formal rate application review; this workbook focuses on collecting your view on competing trade-offs in capital investments.

Voluntary Workbook

Approach to Operating Expenses

Q

Does leaving the detailed discussion about Niagara Peninsula Energy's operating budget to experts from the OEB and intervenors seem like the right approach or wrong approach to you?



INNOVATIVE RESEARCH GROUP

Niagara Peninsula Energy Background

Capital Investments

NPEI's **capital budget** covers items that, once purchased, have lasting benefits over many years. Year-over-year, regardless of external drivers, NPEI will need to make investments in the core distribution system, including poles, wires, cables and transformers.

Based on initial customer input and the approach outlined previously, NPEI believes the capital expenditure required to address system renewal, maintain system reliability and safety, and invest in other infrastructure priorities between 2021 and 2025 is estimated to be **$70.3 million**.

NPEI classifies the costs of four types of capital investment between 2021 and 2025. Each of these four investment categories helps NPEI pace and prioritize projects.

2021-2025 Forecasted Capital Investments

System Renewal ($38.2 million)

These projects are a mix of planned end-of-life replacements and emergency replacements.

Projects Include: Replacement of existing overhead wires, poles, and pole mounted transformers, underground cables and transformers and transformer station upgrades.

System Access ($17.1 million)

"Must do" investments that respond to customer requests for new connections or new infrastructure development.

Projects Include: NPEI's share of new subdivisions, new upgraded commercial and industrial services, and relocating assets based on road infrastructure needs.

General Plant ($8.4 million)

These are investments needed to support the distribution system, such as tools, vehicles, buildings, and computers.

Projects Include: Financial and customer IT systems, enhanced cyber security investments, facility renovations, backup generation, and vehicle replacements.

System Service ($6.6 million)

These investments consist of projects that address capacity constraints, improve system reliability and customer service.

Projects Include: Installation of automated switches and system expansion to supply new development.

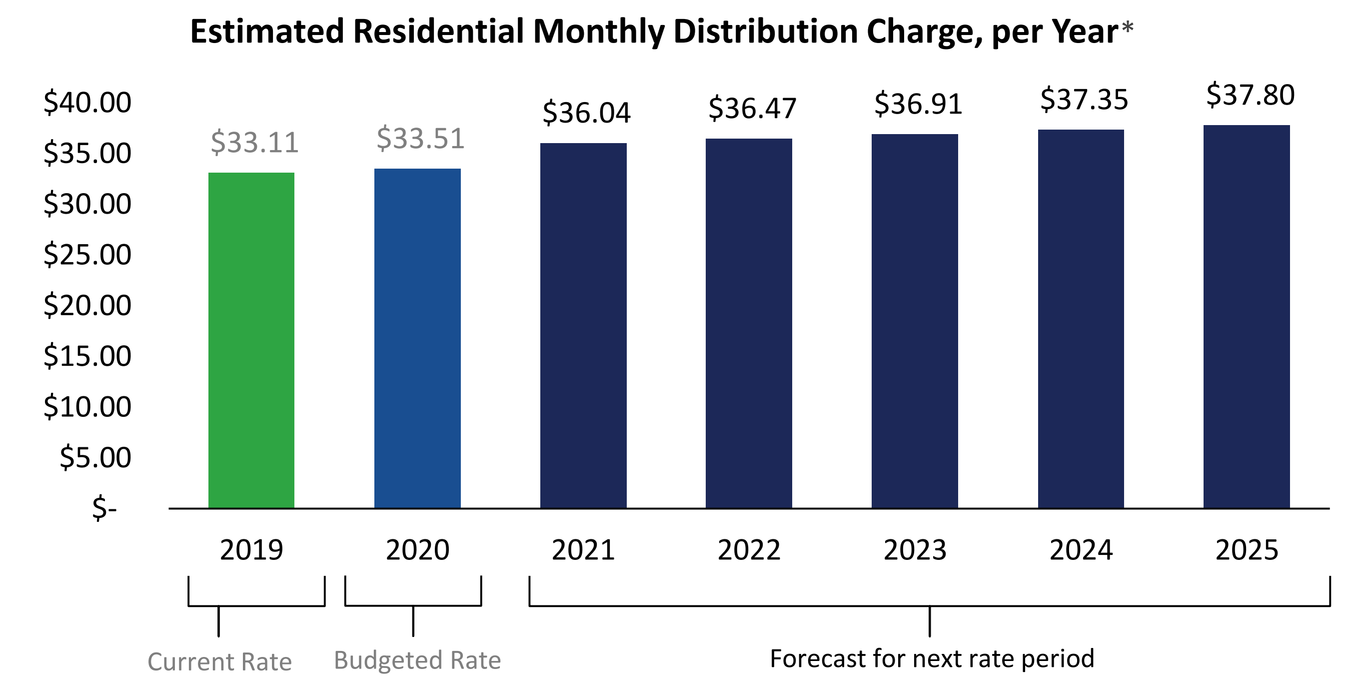
Niagara Peninsula Energy Background

How much will this draft plan cost me?

Remember, the current typical NPEI residential customer's electricity bill is about $113 per month, of which $33.11 goes to NPEI.

It is estimated that if NPEI continues with its preliminary plan, the distribution portion of the bill will increase by $2.53 per month in 2021, when the plan is set to come into effect. For the period 2022-2025, the annual bill increase is limited by the OEB to be less than the rate of inflation.

- At the end of the 5-year plan, the typical residential customer would see the distribution portion of their electricity bill increase by $4.29.
- As a result, the distribution charges on the typical residential customer's monthly bill would increase from $33.51 in 2020 to $37.80 by 2025.



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

NPEI is looking for your input on its preliminary plan to ensure it is making the spending decisions that matter to you, the customer.

The following sections of this workbook will explore some of the choices Niagara Peninsula Energy needs to make to help finalize its preliminary plan.

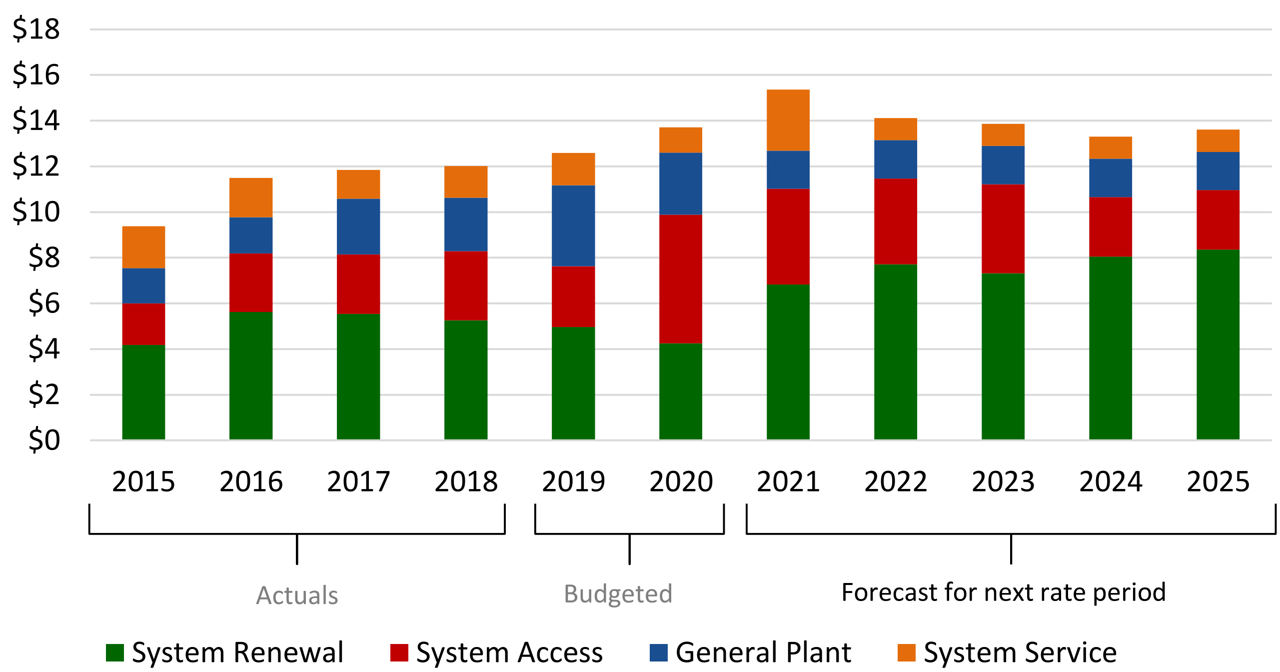
Niagara Peninsula Energy Background

Pacing Capital Investments

The overall amount NPEI invests in capital projects remains generally the same year over year, but what does change is where these investments are made. In some years, when unplanned or unforeseen investments are needed, NPEI will re-allocate funds to make room for these projects within the approved budget. This helps limit the overall amount that the distribution charges fluctuate year-over-year.

The chart below outlines NPEI's spending in past years, and proposed spending for the 5-year period 2021 to 2025.

2015 – 2025 Historical and Forecasted Capital Investments*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

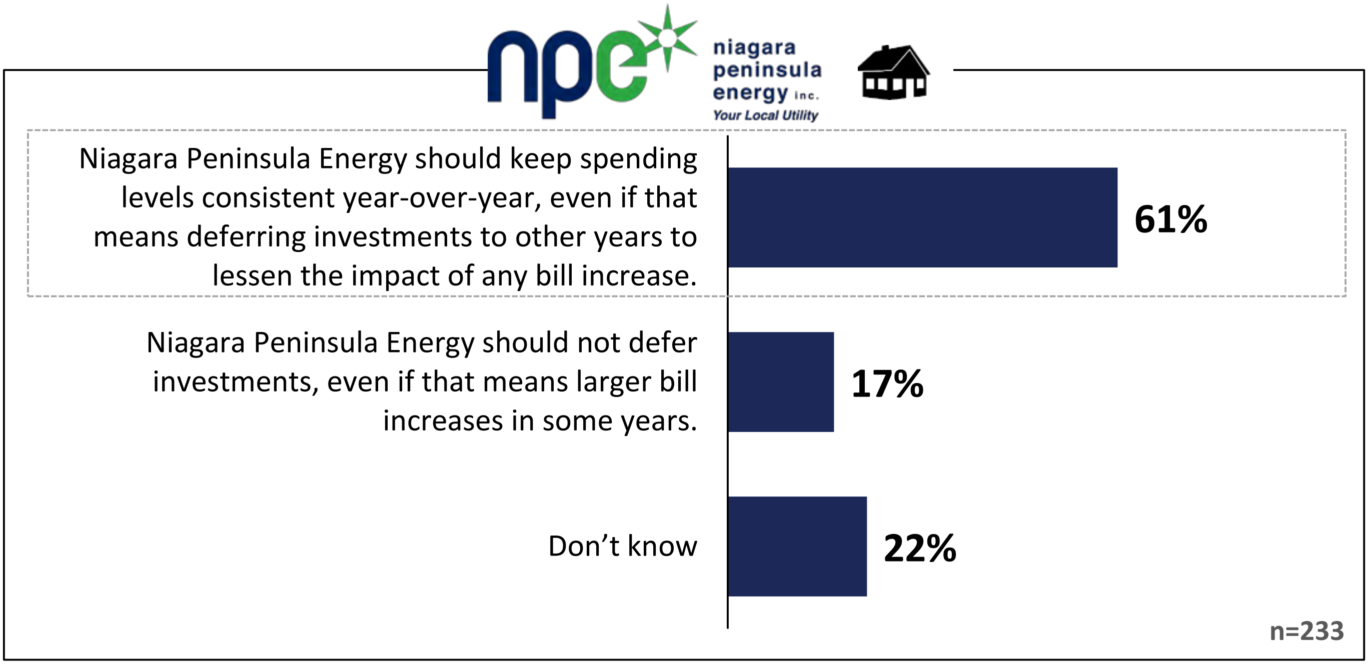
System Access expenditures are budgeted to increase to $5.6M in 2020 to accommodate a number of large commercial customer growth projects as well as municipal road work.

Voluntary Workbook

Approach to Pacing Investments

Residential & Small Business

Q Which of the following statements best represents your point of view regarding Niagara Peninsula Energy's approach to pacing investments?



Q Additional Feedback (Optional)

Additional Feedback (n=22) 91% of respondents did not provide additional feedback	**n-size**
Deferring only increases future prices/invest now in technology and equipment	6
No increase-keep cost low too high already	6
Rate increases should at a reasonable stable rate/ small increases over time when necessary	3
Find efficiencies/cost savings/use profits/capital investments	2
Case by case basis/Prioritize spending on what is needed most	1
Other	4

Niagara Peninsula Energy Background

Mandatory Investments

Federal, provincial, and municipal governments as well as regulators set requirements and standards that NPEI must satisfy. Mandatory investments can be broken down into three categories:

- **Connecting customers**: This includes connecting customers to the grid when a new home or building is constructed or modified.
- **Moving equipment**: This includes moving equipment like poles and cables for road widening.
- **Mandated obligations**: This includes installing and maintaining customer meters and transferring electricity from the provincial transmission system.

These mandatory investments mean that about **one-in-four dollars (23%)** of your distribution rates over the past five years have not been available for other non-mandatory investments. Looking forward to the 2021-2025 period, NPEI forecasts a similar level of mandatory investments, driven largely by:

- **Preparing to connect the new Niagara South hospital;**
- **Work to accommodate the 2021 Canada Summer Games in the Niagara Region, and;**
- **Work to accommodate growth and future electricity capacity needs.**

Voluntary Workbook

Approach to Mandatory Investments

Residential &
Small Business

Q Which of the following statements best represents your point of view regarding Niagara Peninsula Energy's approach to mandatory and non-mandatory spending?

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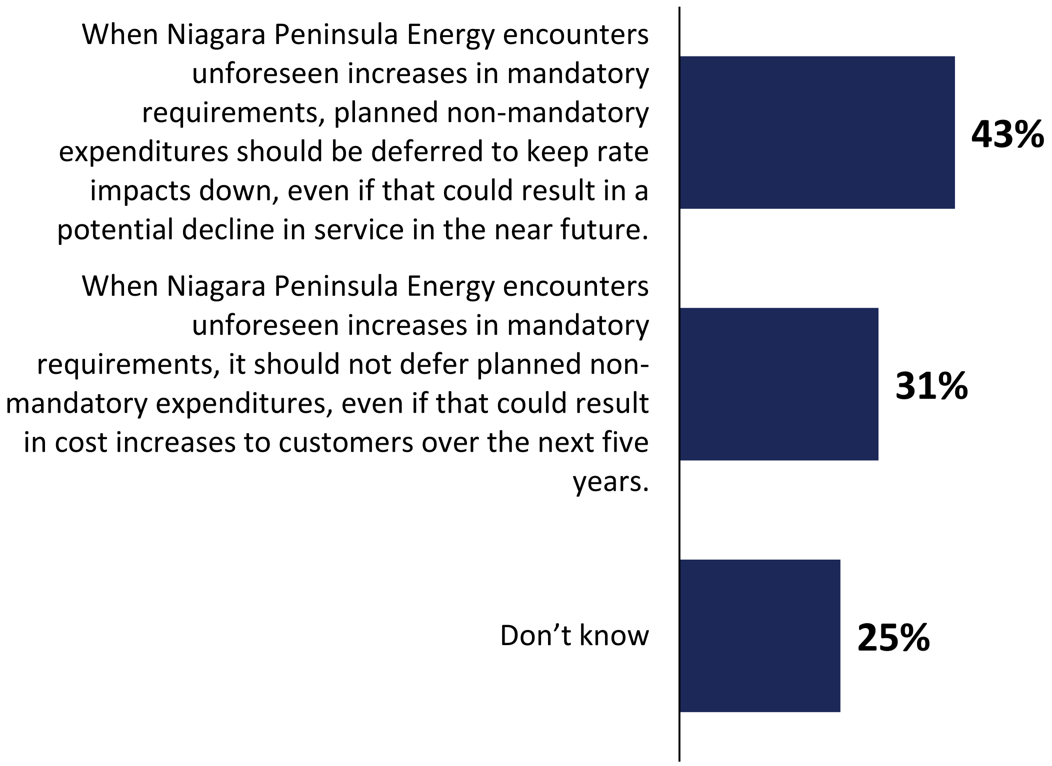


n=233

Q Additional Feedback (Optional)

Additional Feedback (n=18) 92% of respondents did not provide additional feedback	**n-size**
Unforeseen increases should not be encountered/should already be in budget	4
Case by Case basis/New developers/builders/Canada Games/Government- should fund costs	4
Increase within reason when expenditures are necessary/Balance over 5 years	4
Keep rates low/Cost is already to high-no increase	1
Cut back on salaries/operating costs	1
Other	4

Making Choices (1 of 7)

Overhead Pole Replacement

A recent asset health condition assessment shows that **575 or approximately 3%** of the poles in NPEI's distribution system are in *poor* or *very poor* condition. Each year, new poles enter this condition, and NPEI takes an approach that proactively replaces poles as to not create a large backlog. As a general rule, pole failure only causes an outage when something happens outside of the utility's control, most frequently due to trees knocking them down or a car accident.

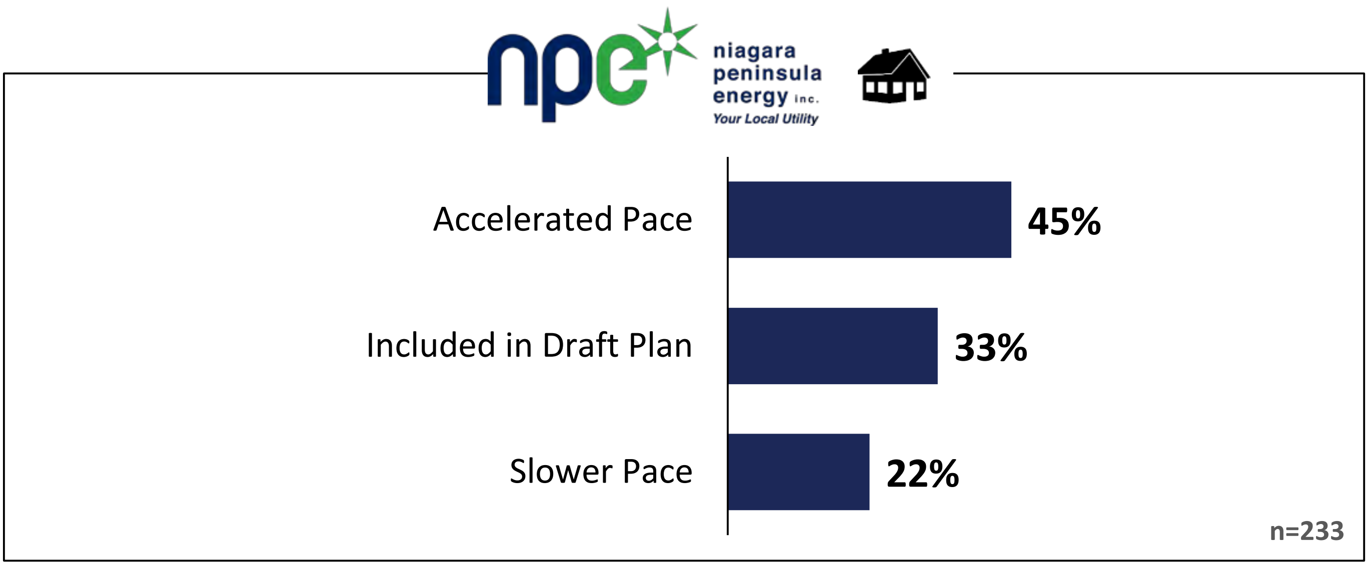
On average, since 2014, NPEI has replaced approximately 88 poles per year. This pace has effectively maintained reliability over this period.

NPEI is proposing to replace most of these 575 poles in poor and very poor condition over the course of the next five years, however, there is an opportunity to replace these poles more quickly or slowly. NPEI must continue to invest in overhead pole replacement, therefore, this is a matter of whether customers would rather pay more during the upcoming period, or push some level of investment beyond the next five years.

Option	Poles Replaced	Expected Outcome
Accelerated Pace ***Additional*** *$0.03 per month annually ($0.36 more per year)*	1,000 by 2025 (200 per year)	Address the very poor and some of the poor condition poles identified in the Asset Condition Assessment.
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	500 by 2025 (100 per year)	Address most of the very poor condition poles identified in the Asset Condition Assessment and annual pole inspections by 2025.
Slower Pace ***Decrease*** *of $0.01 per month annually ($0.12 less per year)*	250 by 2025 (50 per year)	Address only the poles in need of immediate replacement, as identified in the annual pole inspection report.

Voluntary Workbook
Overhead Pole Replacement

Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

Additional Feedback (n=21) 91% of respondents did not provide additional feedback	**n-size**
Bury lines/better to replace with underground lines	5
Cost acceptable	3
Issue due to poor management/maintenance should have been ongoing	3
Be proactive/pay now to save later/costs will only increase	2
Replace as necessary/most urgent first/my street first	2
Replace within budget/no increase to consumer	2
Reliability/safety outweighs cost	1
Investigate/Invest in new pole technology	1
Information misleading/skeptical about figures/inspection criteria	1
None	1

Making Choices (2 of 7)

Overhead transformer replacement

Transformers are a critical piece of distribution equipment that reduce voltage from the higher levels that are more efficient to move electricity long distances to lower levels that are safer to connect to homes and businesses. They are typically either located on the ground, in underground vaults, or attached to distribution poles

A recent asset health condition assessment shows that **1,251 or approximately 21%** of the overhead transformers in NPEI's distribution system are in poor or very poor condition.

Since 2014, overhead transformer failure has directly resulted in approximately 15 outages per year. That said, in most cases, when an overhead transformer fails, it only impacts a small amount of customers and the equipment can be replaced within 2-3 hours depending on the circumstances.

However, when these outages do occur, it can take NPEI crews an extended period of time to replace the cable and restore power to affected households and businesses.

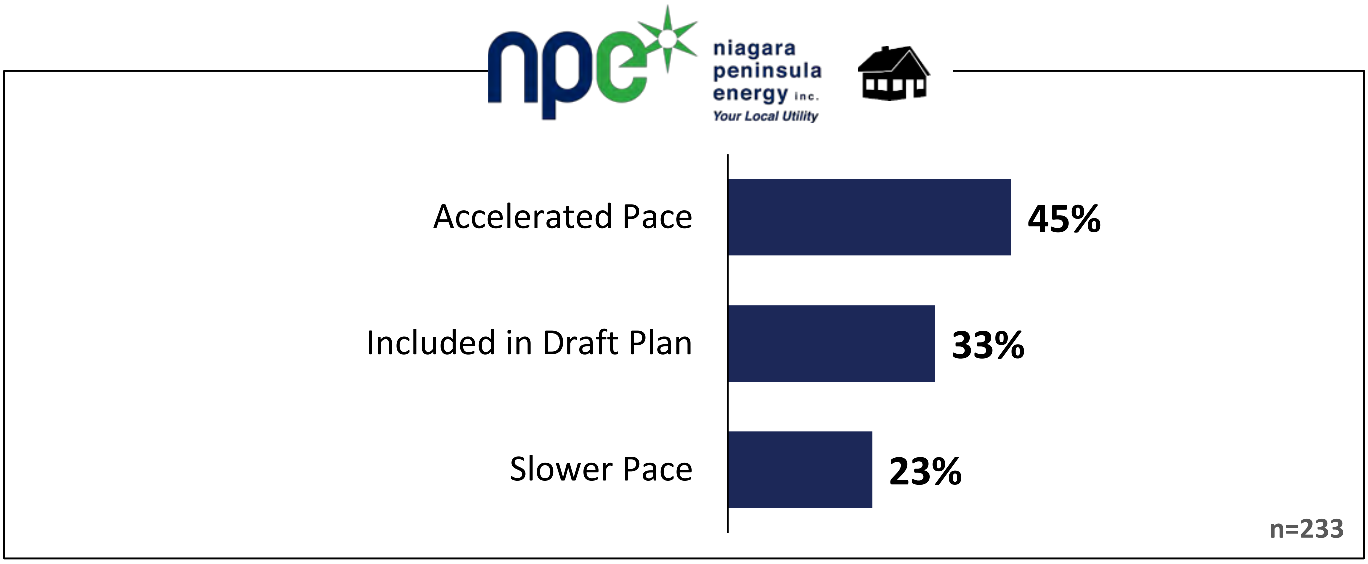
NPEI is proposing a new program to proactively replace **250 of the 677 or 37%** of the overhead transformers identified as very poor condition before they fail over the course of the next five years.

As with distribution poles, NPEI will proactively invest in overhead transformer replacement, therefore, this is a matter of whether customers would rather pay more during the upcoming period, or push some level of investment beyond the next five years.

Option	Transformers Replaced	Expected Outcome
Accelerated Pace ***<u>Additional</u>*** *$0.01 per month annually ($0.12 more per year)*	375 by 2025 (75 per year)	Address some of the polemount transformers identified as very poor in the Asset Condition Assessment report.
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	250 by 2025 (50 per year)	Address some of the polemount transformers identified as very poor in the Asset Condition Assessment report.
Slower Pace ***<u>Decrease</u>*** *of $0.01 per month annually ($0.12 less per year)*	125 by 2025 (25 per year)	Address only the worst of the polemount transformers identified as very poor in the Asset Condition Assessment report.

Voluntary Workbook
Overhead transformer replacement

Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

Additional Feedback (n=16) 93% of respondents did not provide additional feedback	**n-size**
Issue due to poor management/maintenance should have been ongoing	4
Replace within budget/find efficiencies/no increase to the consumer	4
Replace as necessary/most urgent/poor transformers first	3
Cost acceptable/negligible	2
Replace with underground/more secure alternative	2
Be proactive/pay now to save later/costs will only increase	1

INNOVATIVE RESEARCH GROUP

Making Choices (3 of 7)

Converting Outdated Underground Kiosk Transformers

NPEI's system features a type of underground transformer that was popular in the 1940s to 1970s which no longer meets construction and safety standards. While this equipment still functions, it is becoming increasingly difficult to safely and effectively maintain. When this equipment does fail, it can result in lengthy outages due to the limited accessibility due to the original method of construction.

On average, since 2014, NPEI has converted approximately 9 kiosk transformers per year. Between 2018 and 2019, the pace of this program has been pushed off, and today, there remains 75 transformers in need of replacement.

NPEI is proposing to convert all of this equipment within the next seven years, with 55 being converted in the next five year period. That said, there is an opportunity to convert these kiosk transformers more slowly.

Option	Transformers Installed	Expected Outcome
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	55 by 2025 (11 per year)	Work towards eliminating all old installations over the next 7 years.
Reduced Pace ***Decrease*** *of $0.02 per month annually ($0.24 less per year)*	25 by 2025 (5 per year)	Work towards eliminating all old installations over the next 15 years.
Slower Pace ***Decrease*** *of $0.03 per month annually ($0.36 less per year)*	10 by 2025 (2 per year)	Work towards eliminating all old installations over the next 35 years.

Voluntary Workbook

Converting Outdated Underground Kiosk Transformers

Residential &
Small Business

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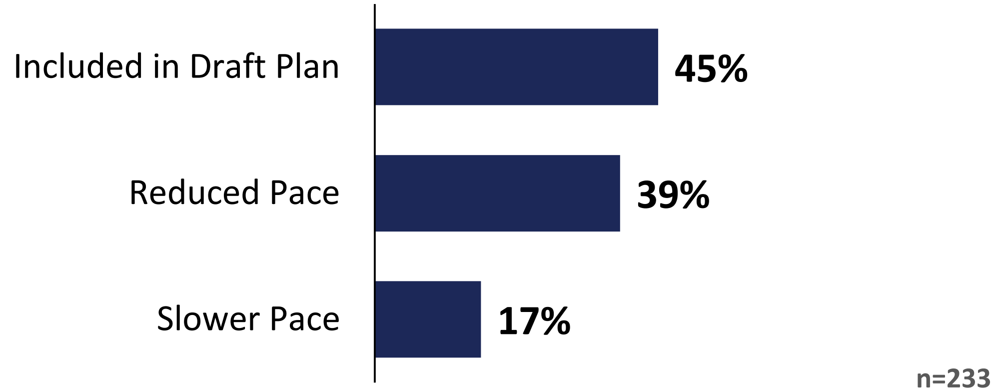
Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

Additional Feedback (n=11) 95% of respondents did not provide additional feedback	**n-size**
Replace within budget/find efficiencies/no increase to the consumer	4
Reliability/safety outweighs cost	2
Be proactive/	2
Replace as necessary/most urgent/outdated first/run to fail	2
Issue due to poor management/maintenance should have been ongoing	1

INNOVATIVE RESEARCH GROUP

Making Choices (4 of 7)

Underground cable replacement

Many neighbourhoods across NPEI's service territory are serviced by underground cables. Historically, NPEI has taken a "run-to-failure" approach with this equipment; that is, a cable will be replaced only once it has failed. The age of this equipment is now becoming a concern, with approximately 78 km or 18% of underground cable operating beyond its estimated useful life of 35 years.

Since 2014, underground cable failure has directly resulted in approximately ten outages per year, and when these outages do occur, it can take NPEI crews an extended period to replace the cable and restore power to affected households and businesses.

Between 2021 and 2025, NPEI is proposing a new program that will replace cable that has been identified as past end of life when completing other associated work. NPEI believes that this could help reduce the number and length of outages caused by underground cable failure, as well as to start getting ahead of the ongoing age issue. That said, there is an opportunity to take a more proactive approach to addressing some of the older cable in the system.

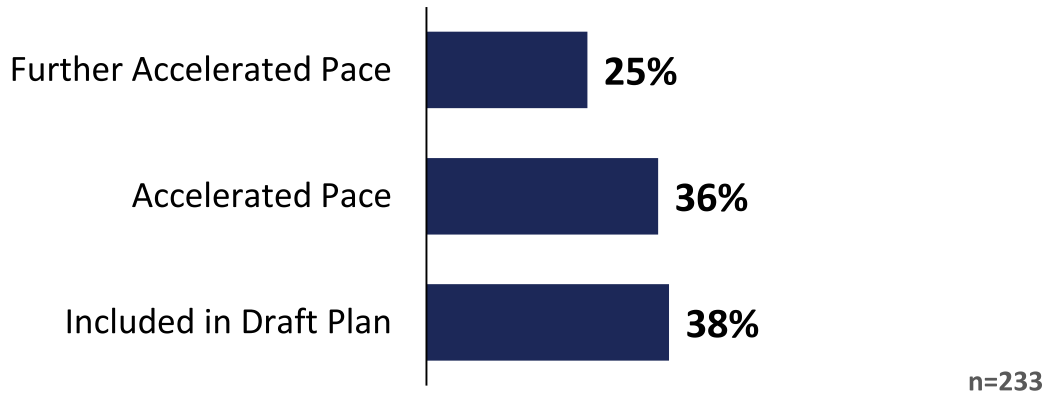
Option	Km of cable installed	Expected Outcome
Further Accelerated Pace ***Additional*** *$0.13 per month annually ($1.56 more per year)*	24 km by 2025 (4.8 km per year)	Proactively replace more of the cables identified as past end of life in the Asset Condition Assessment Report.
Accelerated Pace ***Additional*** *$0.06 per month annually ($0.72 more per year)*	12 km by 2025 (2.4 km per year)	Proactively replace some of the cables identified as past end of life in the Asset Condition Assessment Report.
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	2 km by 2025 (0.4 km per year)	Replace cables past end of life as other work is being completed on associated switchgear or riser poles.

Voluntary Workbook

Underground cable replacement

Residential & Small Business

Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

Additional Feedback (n=10) 96% of respondents did not provide additional feedback	**n-size**
Be proactive/pay now to save later/costs will only increase	2
Reliability/safety outweighs cost	2
Replace within budget/no increase to consumer/cash grab	2
Bury lines/better to replace with underground lines	1
Issue due to poor management/maintenance should have been ongoing	1
Improve cable assessments/more investigation required	1
Other	1

Making Choices (5 of 7)

Subdivision underground rehabilitation

71 of the subdivisions in NPEI's service territory were constructed with **direct buried cable** which refers to a type of construction where cables are laid directly in underground trenches without a protective barrier.

While this was typical construction at the time, 40 of these subdivisions were built 40 or more years ago, and the cables are now approaching the end of their recommended life.

In this upcoming plan, NPEI is proposing a new program to start preparing to upgrade the service in the subdivisions with the most pressing needs.

In order to keep costs down, NPEI is proposing to start rehabilitation of the underground "system" by installing ducts that will eventually carry underground cables over the next five years. The cables would be installed as needed (upon failure) or once all of the old subdivisions have had the duct installed.

Completing this work in two phases will not only save costs now, but also help ensure that NPEI will be able to rehabilitate the most subdivisions in the shortest time.

Between 2021 and 2025, NPEI is proposing a new program that will proactively install ducts in approximately 10 subdivisions. Which subdivisions receive investment first will predominantly be based on age. That said, there is an opportunity to either accelerate or slow down the pace of this new program.

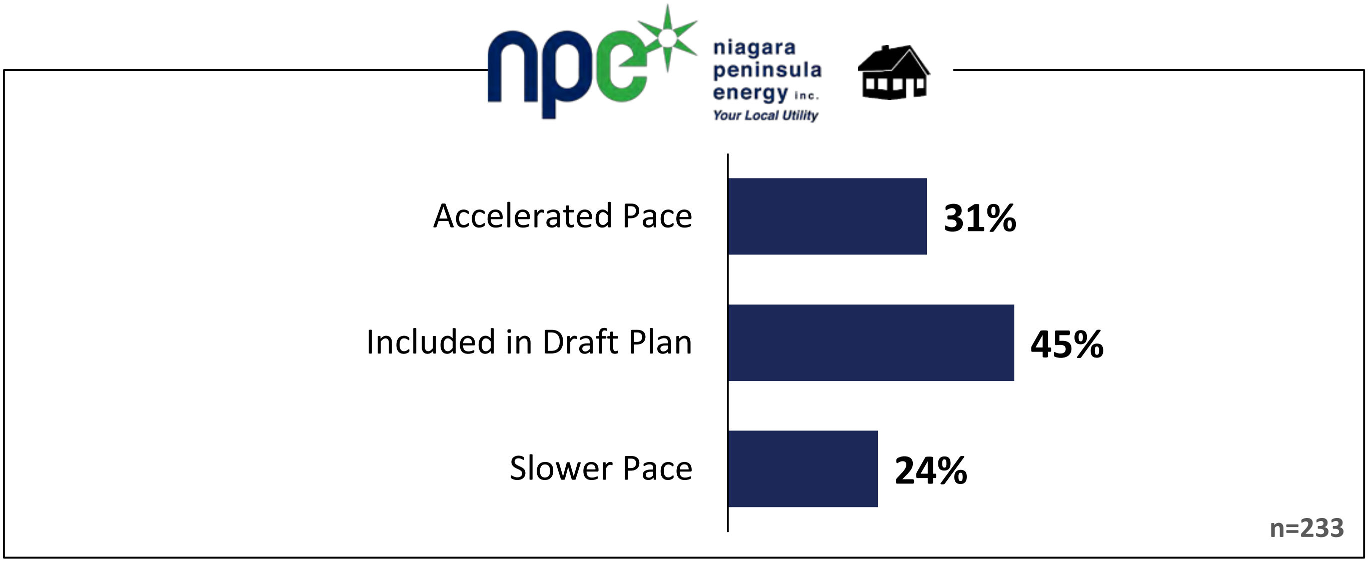
Option	Km of vault installed	Expected Outcome
Accelerated Pace ***Additional*** *$0.02 per month annually ($0.24 more per year)*	30 km by 2025 (6 km per year)	Install 6 km of ducts or approximately four subdivisions per year.
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	15 km by 2025 (3 km per year)	Install 3 km of ducts or approximately two subdivisions per year.
Slower Pace ***Decrease*** *of $0.01 per month annually ($0.12 less per year)*	7.5 km by 2025 (1.5 km per year)	Install 1.5 km of ducts or approximately one subdivision per year.

Voluntary Workbook

Subdivision underground rehabilitation

Residential & Small Business

Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

Additional Feedback (n=9) 96% of respondents did not provide additional feedback	**n-size**
Charge new developments/Only affected customers should pay	3
Issue due to poor management/maintenance should have been ongoing	2
Need more information	1
Replace as necessary/most urgent first	1
Replace within budget/no increase to consumer	1
Information misleading/skeptical about figures/inspection criteria	1

Making Choices (6 of 7)

Overhead rebuilds

Beyond replacing overhead poles, NPEI has a program that rebuilds the overhead system for entire streets and neighbourhoods. This includes poles, wires, and all other equipment that goes into operating the overhead system.

A recent asset health condition assessment identified a total of **60 areas** within NPEI's service territory that require complete overhead rebuilds**.** Most of this equipment is either beyond its recommended age or deteriorated due to weather and other factors. This infrastructure is in addition to the poles identified in the earlier section.

This program is intended to contribute to the "betterment" of the overhead system by;

- Improving system performance by installing animal guards and higher capacity transformers to reduce the likelihood of outages, and;
- Improving system aesthetics with new and taller poles.

On average, each of the projects would replace approximately 30-40 poles, depending on the population density of the area being worked on. NPEI's current approach would rebuild **40 out of 60 areas** in the 2021 to 2025 period.

NPEI must continue to invest in overhead rebuilds, therefore, this is a matter of whether customers would rather pay more during the upcoming period or push some level of investment beyond the next five years.

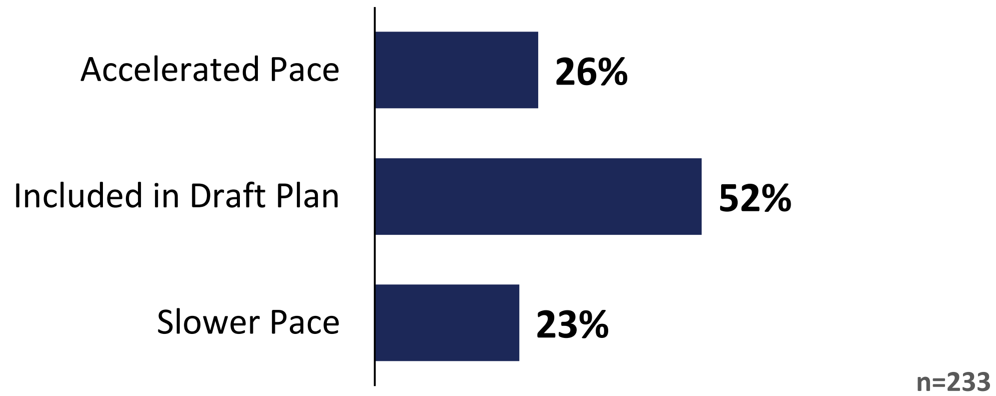
Option	**Overhead rebuilds**	**Expected Outcome**
Accelerated Pace ***Additional*** *$0.03 per month annually ($0.36 more per year)*	61 km by 2025 (12.2 km per year)	Rebuild 12.2 km per year or approximately 10 projects per year
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	48.5 km by 2025 (9.7 km per year)	Rebuild areas with assets that have been identified as very poor in Asset Condition Assessment. Rebuild 9.7 km per year or approximately 8 projects per year
Slower Pace ***Decrease*** *of $0.03 per month annually ($0.36 less per year)*	36 km by 2025 (7.2 km per year)	Rebuild 7.2 km per year or approximately 6 projects per year

Voluntary Workbook

Overhead rebuilds

Residential & Small Business

Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

Additional Feedback (n=13) 94% of respondents did not provide additional feedback	**n-size**
Replace within budget/find efficiencies/no increase to consumer	4
Bury lines/better to replace with underground lines	3
Coordinate with other services/find other revenue streams/charge new developments	3
Improve infrastructure/protect from animals	3

Making Choices (7 of 7)

Grid modernization

New technology has changed the way that NPEI can manage and monitor the distribution system.

Supervisory Control and Data Acquisition (SCADA) systems allow NPEI staff the ability to remotely monitor and trace system faults and re-close switches from a control room rather than sending a repair crew to patrol the lines. These systems are particularly effective where there are larger distances between customers, for instance, in more rural areas of the western region of NPEI's service territory.

This equipment can have significant positive impacts on restoration times when an outage does occur, particularly in instances such as during a severe weather event.

On average, since 2014, NPEI has installing approximately two remote devices per year, with focus on more rural, lower density areas. That said, there is an opportunity to install this monitoring and control equipment more quickly or slowly.

Option	Devices installed	Expected Outcome
Accelerated Pace ***Additional*** *$0.01 per month annually ($0.12 more per year)*	20 devices (4 per year)	NPEI to double installation rate to four devices per year.
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	10 Devices (2 per year)	Remain at current installation pace of two devices per year. Install new devices to expand NPEI's Smart Grid network. These devices provide better monitoring capability on the system, which leads to improved restoration times during outages.
Slower Pace ***Decrease*** *of $0.005 per month annually ($0.06 less per year)*	5 Devices (1 per year)	NPEI to cut rate of installation in half to one device per year.

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Grid modernization

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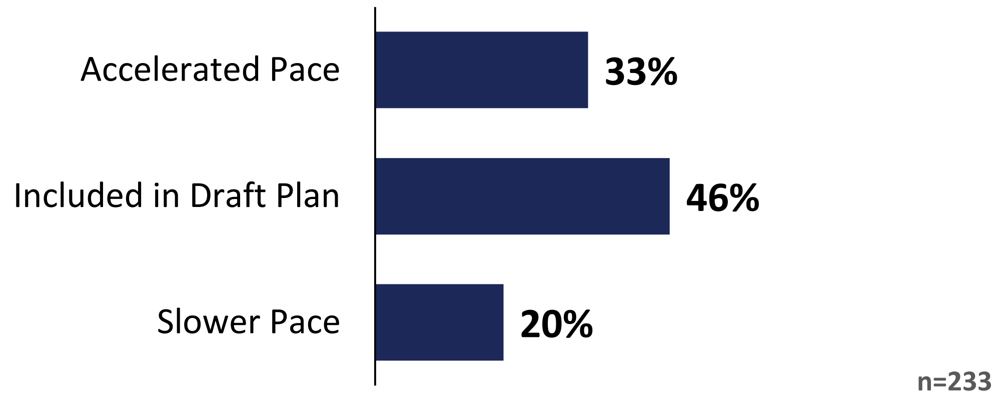
Q Which of the following options do you prefer?



Q Additional Feedback (Optional)

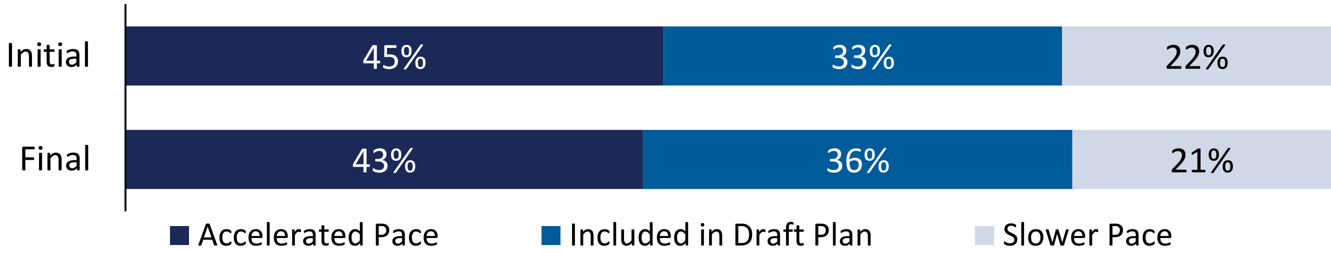
Additional Feedback (n=11) 95% of respondents did not provide additional feedback	**n-size**
Be proactive/pay now to save later/costs will only increase	2
Keeping consumer costs low should be a priority/cost already high	2
Cost acceptable	1
Only affected customers should pay	1
Reliability/safety outweighs cost/protect grid/upgrade	1
Replace within budget/find efficiencies	1
Other	2
None	1

Voluntary Workbook

Change in Initial vs. Final Response by Project

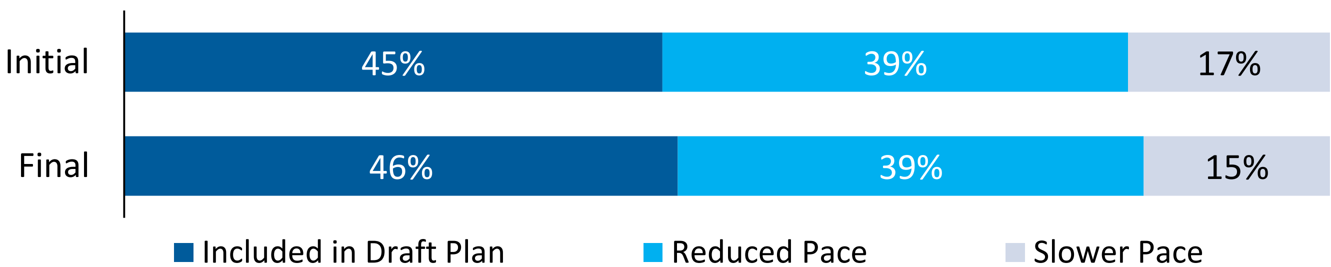
Residential & Small Business

Q Overhead Pole Replacement

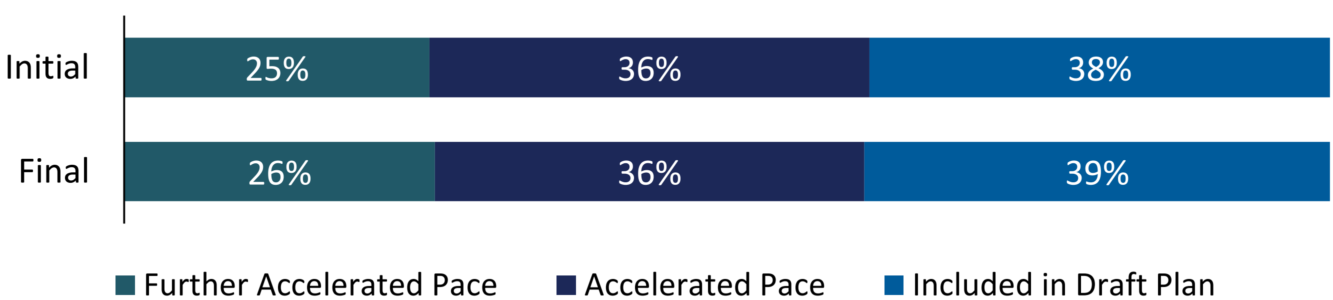


Q Overhead Transformer Replacement

Q Converting Outdated Underground Kiosk Transformers



Q Underground Cable Replacement



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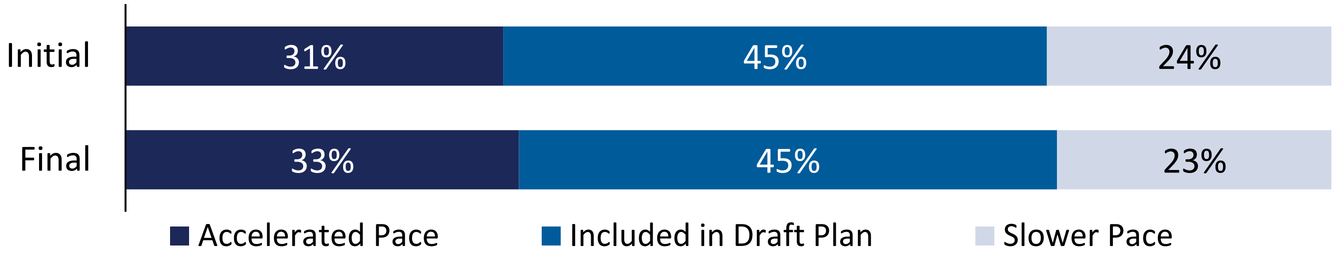
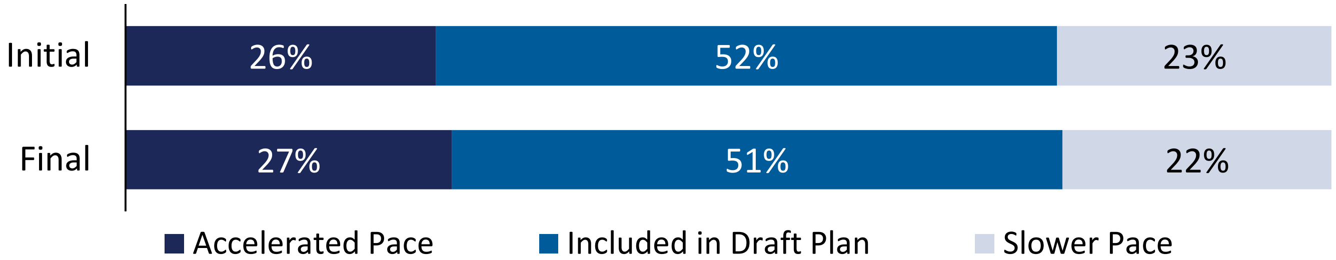
Change in Initial vs. Final Response by Project

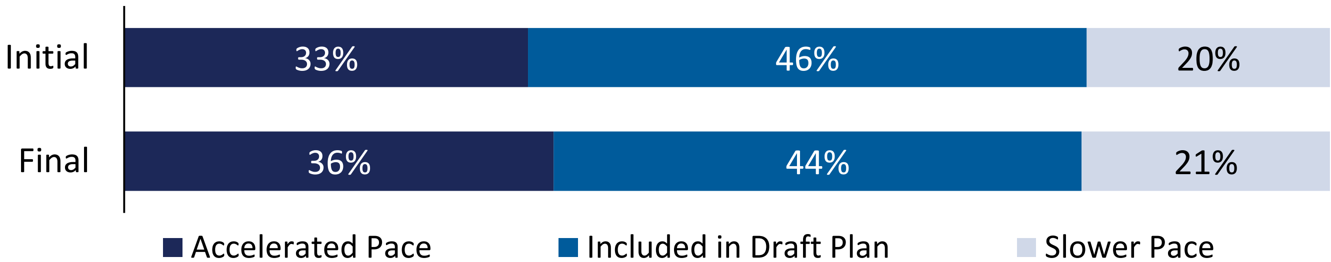
Q Subdivision Underground Rehabilitation



Q Overhead Rebuilds



Q Grid Modernization



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Impact of Choices

Assessing Niagara Peninsula Energy's draft 2021-2025 plan

Again, it is estimated that if NPEI continues with its preliminary plan, the distribution portion of the bill will increase by $2.53 per month in 2021, when the plan is set to come into effect. For the period 2022-2025, the annual bill increase is limited by the OEB to be less than the rate of inflation.

- At the end of the 5-year plan, the typical residential customer would see the distribution portion of their electricity bill increase by $4.29.
- As a result, the distribution charges on the typical residential customer's monthly bill would increase from $33.51 in 2020 to $37.80 by 2025.

Estimated Typical Residential Annual Increase in Monthly Bill (5 year forecast)

	Year	Average Residential Bill	Distribution Portion of Bill	Incremental Rate Change	% Change * (on distribution portion of bill)
Current Rate	2019	$113.32	$33.11		
Budgeted Rate	2020	$115.03	$33.51	$0.40	1.21%
Forecast for next rate period	2021	$116.33	$36.04	$2.53	7.55%
	2022	$118.08	$36.47	$0.43	1.20%
	2023	$119.85	$36.91	$0.44	1.20%
	2024	$121.65	$37.35	$0.44	1.20%
	2025	$123.47	$37.80	$0.45	1.20%
				$4.29	

*** These estimates are preliminary, and are subject to your feedback as the business plan is finalized .**

Voluntary Workbook

Assessing Niagara Peninsula Energy's draft 2021-2025 plan

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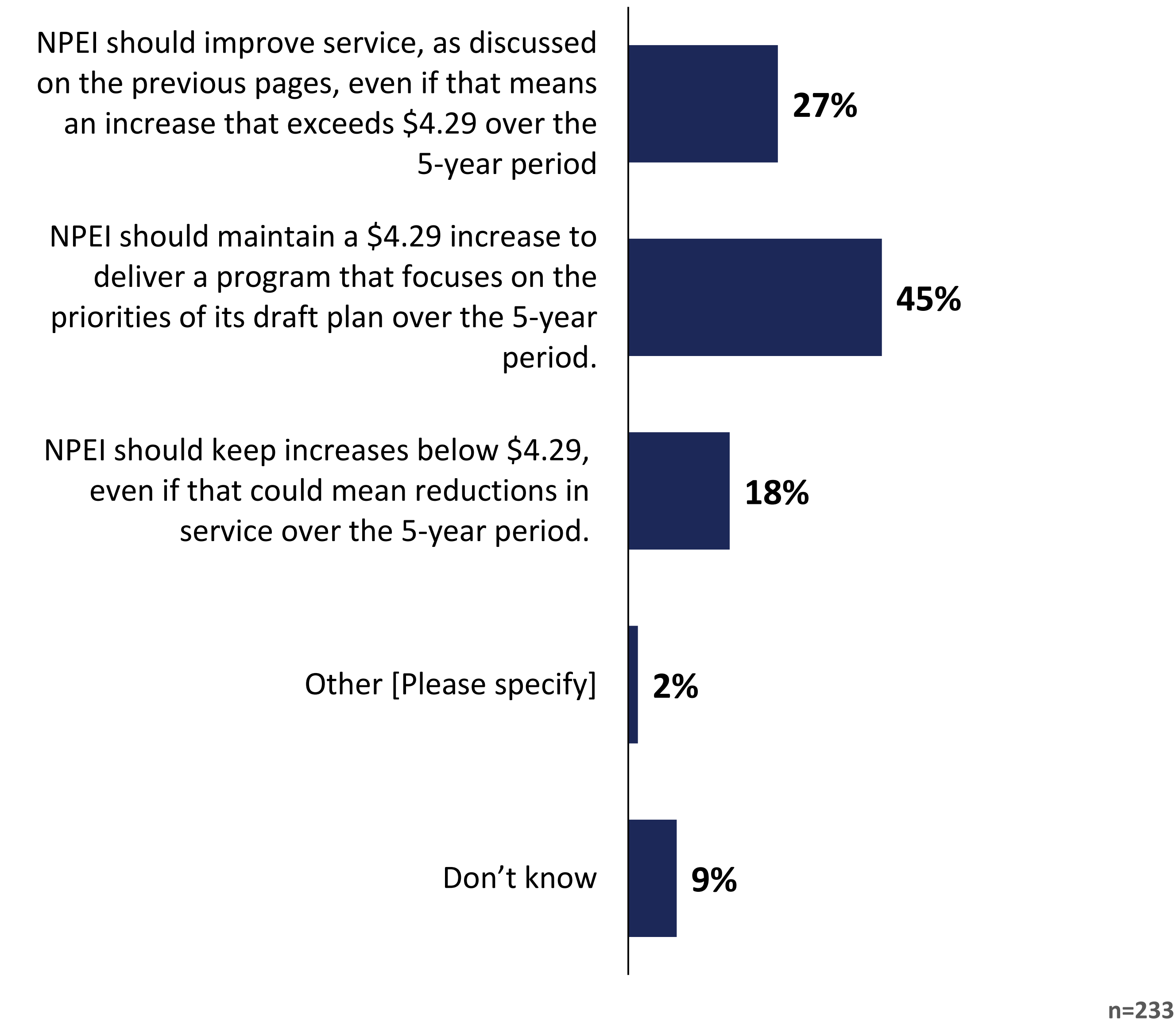
Q Considering what you know about Niagara Peninsula Energy's draft plan – which would see the typical residential customer's distribution portion of their bill increase by $4.29 over the 5-year period – which of the following best represents your point of view?



Voluntary Workbook

Final Comments

Q Thinking about your answer to the previous question, why do you feel that NPEI should take that approach over the 2021-2025 period?

Final Comments (n=65) 72% of respondents did not provide additional feedback	**n-size**
Proactive approach-Pay now to ensure proper maintenance and prevent higher cost in the future	20
rates are high enough already/no increase	17
Increase is reasonable -taking affordability into account	16
Unforseen issues and maintenace should have already been planned in current budget	2
look for efficiencies to offset cost	2
Prioritize necessary improvements /repair as needed	1
Find alternative funding-Customers should not bear cost increase	1
Balance approach	1
Other	4
None	1

Q Do you have any final comments regarding NPEI or the customer engagement that you just completed?

Final Comments (n=28) 88% of respondents did not provide additional feedback	**n-size**
Positive - General NPEI/Survey/ asking for Customer input/informative	10
Cost issues/delivery fees/High rates/keep cost low	7
Invest now to avoid higher cost in the future/Maintain and repair accordingly	5
Transparency-future planning	1
Other	1
None	4

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Final Thoughts: Workbook Diagnostics

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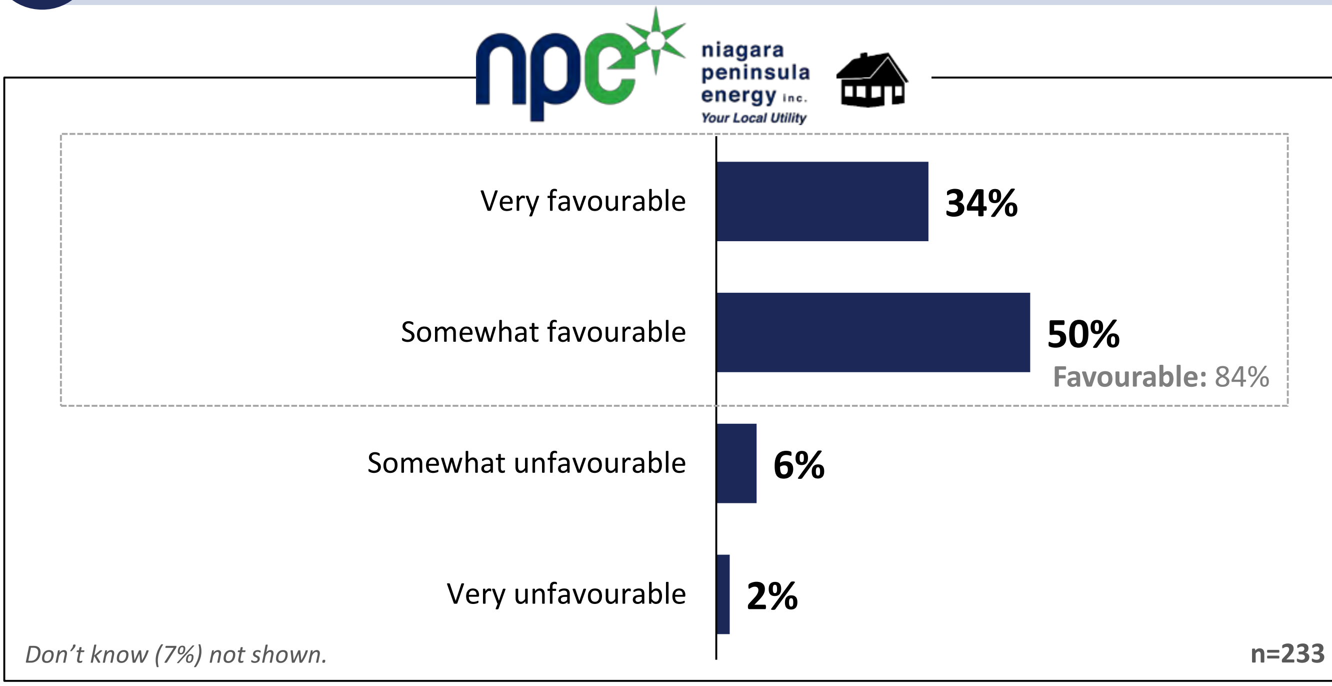
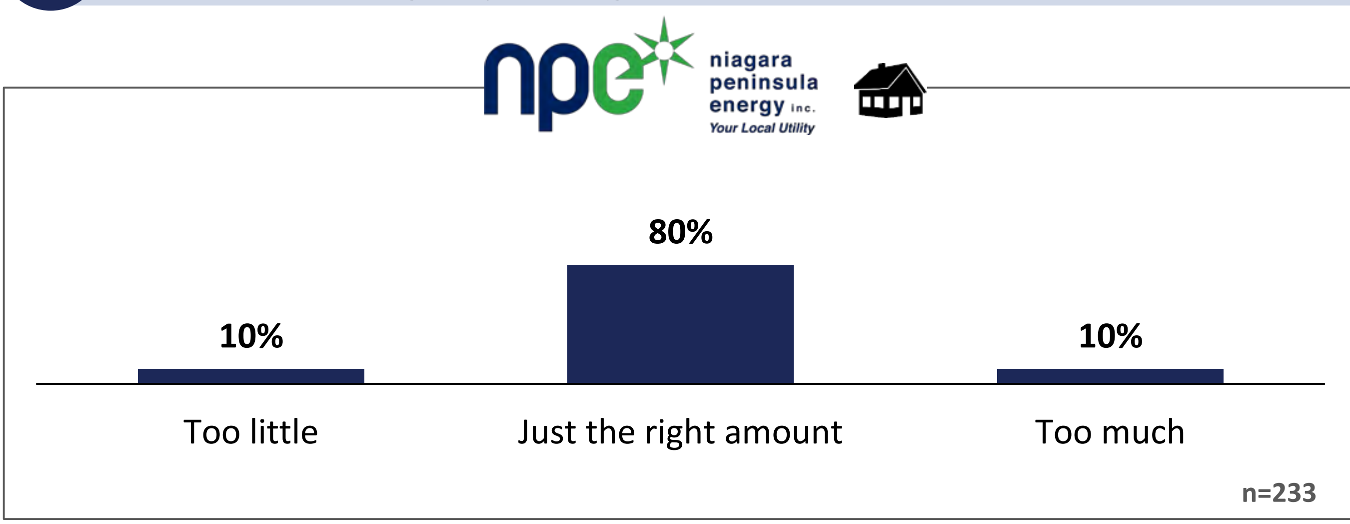
Q **Overall Impression**: Overall, did you have a favourable or unfavourable impression of the consultation you just completed?



Q **Volume of Information:** In this consultation, do you feel that NPEI provided too much information, not enough, or just the right amount?



Voluntary Workbook

Content Covered and Unanswered Questions

Q Was there any content missing that you would have liked to have seen included in this consultation?

Content Covered (n=233)	n-size
None	205
Operating costs/Executive-Salaries/bonuses	8
Cost/delivery fees/High rates/keep cost low	6
transparency/breakdown of cost allocation	4
Alternative energy sources/Turbine/Solar/renewable	2
Going underground/bury lines/cost	1
More information on system reliability aging infrastructure/preventative measures	1
Other	6

Q Is there anything that you would still like answered?

Unanswered Questions (n=233)	n-size
None	218
Cost issues/delivery fees/High rates/keep cost low	4
Operating costs/Executive-Salaries/bonuses	3
Consultations with Customers/ updates as to what course of action and plan will be taken	1
Transparency-Cost allocation	1
Infrastructure repairs/ updates	1
Positive - General NPEI/Survey/ asking for Customer input/informative	1
Other	4

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Appendix 7.0

Customer Engagement

Workbook

Residential Workbook

November 2019

STRICTLY PRIVILEGED AND CONFIDENTIAL

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About this Consultation

Welcome to Niagara Peninsula Energy's Customer Engagement!

Niagara Peninsula Energy (NPEI) needs your input on choices that will impact the services you receive and the rates that you pay.

- **NPEI** is developing its investment plan for 2021 to 2025. This plan will determine the investments NPEI will make in equipment and infrastructure; the services it provides; and the rates you pay.
- As **NPEI** plans for the future, they want to ensure their business decisions are aligned with customers priorities, preferences, and needs.
- Throughout this survey, information will be provided in an effort to give you more background on which to base your responses.
- While responding to the following questions, remember that there are no wrong answers, and that your individual responses will remain anonymous.
- This customer engagement will take approximately 25-35 minutes to complete, depending on the level of feedback you wish to provide. Your progress will be saved as you move through the workbook, meaning you can leave and return to the customer engagement at any time.

All individual responses will be kept confidential. Innovative Research Group (INNOVATIVE), an independent research company, has been hired NPEI to gather your feedback.

Those who complete the questions that follow will be invited to enter a draw to win one (1) $500 cash prize.

About this Consultation

Thank you for your interest in being a part of Niagara Peninsula Energy's customer engagement.

If you are reading this on a smaller mobile device, you may want to consider accessing the survey from a tablet, desktop or laptop instead so that it is easier for you to read.

Would you like to complete this survey on behalf of your business/organization, or your home?

o Business/organization

o Home

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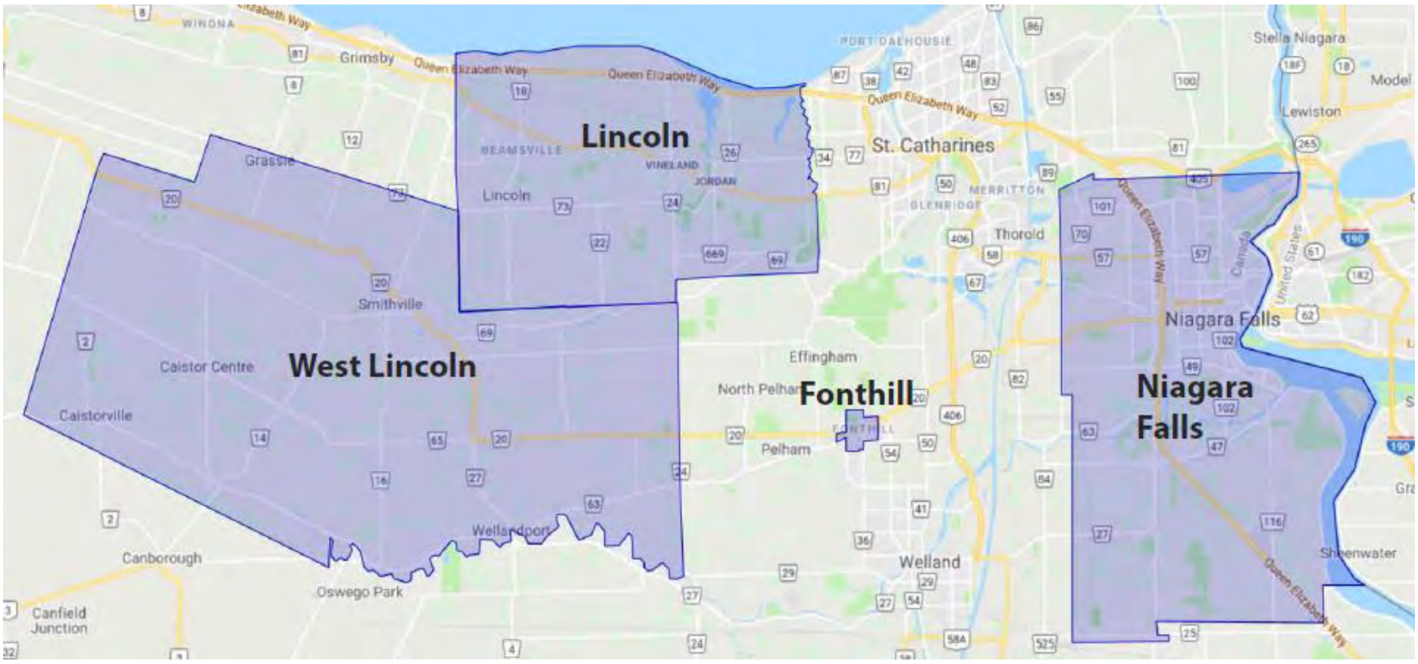
Electricity 101

Who is Niagara Peninsula Energy?

NPEI provides local electricity distribution and related services to residential and business customers in the City of Niagara Falls, Town of Lincoln, Town of Pelham, and Township of West Lincoln.

- NPEI serves an area of approximately 827 square kilometers and 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 local distribution company (LDC) and regulated entity, NPEI applies for, and receives approval from the regulator to charge for its services.



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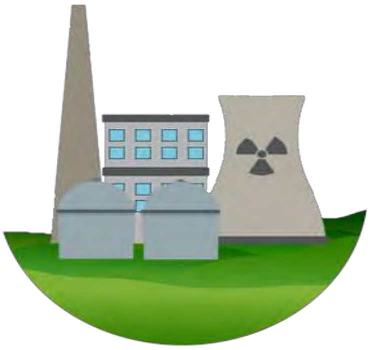
Electricity 101

Niagara Peninsula Energy's Role in Ontario's Electricity System

Ontario's electricity system is owned and operated by public, private, and municipal corporations across the province. It is made up of three key components: **generation**, **transmission** and **distribution**.

Generation

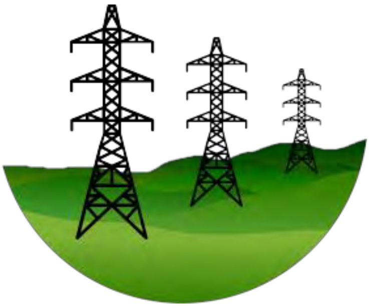
Where electricity comes from



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.

Transmission

How electricity travels across Ontario



Once generated, electricity must be transported to electrical substations 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 kilometres of 'electricity highway', most of which is owned and operated by Hydro One.

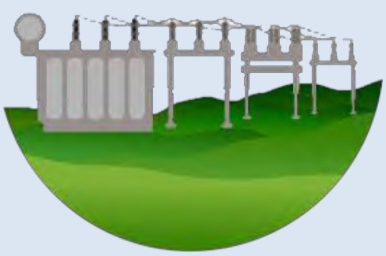
Local Distribution

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. This local distribution system includes transformer stations that decrease the voltage of the electricity so it can be used safely in your home or business.

There are approximately 1,451 km of overhead power lines and 573 km of underground cable. Through this distribution network, NPEI delivers electricity to approximately 55,600 residential and business customers.

Niagara Peninsula Energy Inc. is jointly owned by the **City of Niagara Falls**, the **Town of Lincoln**, the **Town of Pelham** and the **Township of West Lincoln**.



npe niagara peninsula energy Inc.
Your Local Utility

Q1. Before this survey, how familiar were you with Niagara Peninsula Energy, which operates the electricity distribution system in your community?

- ☐ Very familiar
- ☐ Somewhat familiar
- ☐ Not familiar at all
- ☐ Don't know

Niagara Peninsula Energy Customer Engagement

Planning for the Future: 2021-2025 Rate Application

Electricity 101

How much of my electricity bill goes to Niagara Peninsula Energy?

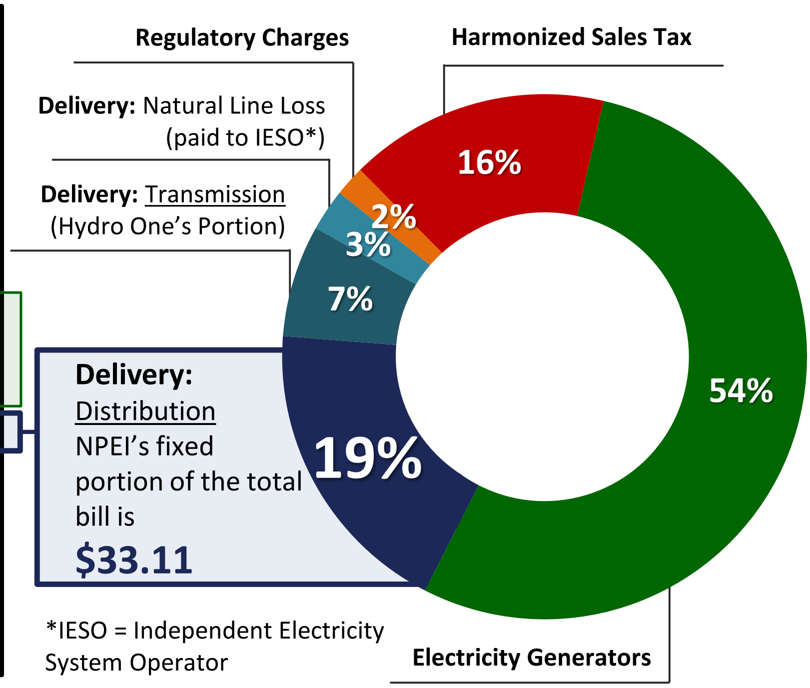
- Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board (OEB), the provincial energy regulator.
- While NPEI is responsible for collecting payment for the entire electricity bill, it retains only the distribution portion of the delivery charge.
- Distribution makes up about **19%** of the typical residential customer's bill.
- For residential customers, NPEI's portion of the delivery line on the bill is fixed and does not change based on the amount of electricity you use.
- The rest of your bill is passed onto provincial transmission companies, power generation companies, the government and regulatory agencies.

NPEI Sample Monthly Bill*
(Based on monthly usage of 700 kWh)

Account Number:
000 000 000 000 0000

Meter Number:
00000000

Your Electricity Charges	
Electricity	
Off-Peak @ 10.1 ¢/kWh	**45.25**
Mid-Peak @ 14.4 ¢/kWh	**18.14**
On-Peak @ 20.8 ¢/kWh	**26.21**
Delivery	**46.85**
Regulatory Charges	**3.11**
Total Electricity Charges	**$139.56**
HST	**18.14**
Ontario Electricity Rebate*	**(-$44.38)**
Total Amount	**$113.32**



* As of November 1, 2019. Chart is based on total bill amount after applying the Ontario Electricity Rebate.

Q2. Thinking specifically about the services provided to you and your community by Niagara Peninsula Energy, overall, how satisfied or dissatisfied are you with the services that you receive?

- ☐ Very satisfied
- ☐ Somewhat satisfied
- ☐ Neither satisfied nor dissatisfied
- ☐ Somewhat dissatisfied
- ☐ Very dissatisfied
- ☐ Don't know

Q3. Before this survey, how familiar were you with the amount of your electricity bill that went to Niagara Peninsula Energy?

- ☐ Very familiar
- ☐ Somewhat familiar
- ☐ Not familiar
- ☐ Don't know

Q4. Is there anything in particular you would like Niagara Peninsula Energy to do to improve its services to you?

Niagara Peninsula Energy Background

Building Niagara Peninsula Energy's draft plan

NPEI has put together its draft business plan based on the information and input from various sources, such as:

- **Legal and regulatory** requirements by continuing to meet its obligations.
- **Internal business planning** based on expert analysis and professional judgment to develop construction and operations programs that address safety, business, technical, and operational needs.
- **Customer feedback** collected through both ongoing dialogues and specific engagements, such as this.

There are three key organizations responsible for setting the policy direction of Ontario's electricity system. The decisions made by these organizations impact how utilities operate their businesses and serve their customers.

- **Policy**: The Ontario Ministry of Energy, Northern Development and Mines (MNDM) creates energy policy for the province.
- **Regulation**: The electricity industry in Ontario is regulated by the Ontario Energy Board (OEB). One of the OEB's roles is to review the business and distribution plans of all electricity distributors and approve the rates that they charge customers.
- **Operations and Planning**: The Independent Electricity System Operator (IESO) manages the provincial electricity grid, plans for the province's future energy needs, and develops conservation programs.

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Niagara Peninsula Energy Background

How did customer feedback shape Niagara Peninsula Energy's draft plan?

NPEI is placing more emphasis on incorporating customer feedback into the planning process than ever before.

NPEI engages with its customers both in day-to-day interactions and in a variety of customer engagement activities. These interactions help identify customer needs and preferences, and inform how the utility plans for the future.

This past summer, NPEI engaged with **thousands of residential and business customers** from across its service territory – both in person and through telephone and online surveys.

What did NPEI hear from customers like yourself?

1. The clear majority of NPEI residential and small business customers are satisfied with the current service they receive. When asked how NPEI can improve service, top responses for residential customers were "nothing", followed by "lower or reduce rates".

2. Among competing outcomes, **price**, **reliability**, and **finding internal cost efficiencies** are the top three priorities for both residential and small business customers.

3. While keeping price at a reasonable and affordable level is an important priority, many customers feel that investing in the grid to maintain reliability, is preferable to deferring investments to keep bills low.



Considering this feedback, as well as the information and inputs discussed on the previous page, NPEI has developed a draft plan that is responsive to:

1. Legal requirements by continuing to meet its obligations, including safety and reliability;

2. A transformer station upgrade to accommodate the new Niagara South Hospital and future surrounding growth.

3. Mandatory service connections to accommodate new customers and customer-required upgrades, of which NPEI does not have control over how and when these costs are incurred.

4. Customer feedback by:

    a) Keeping distribution price increases as low as possible;

    b) Maintaining long-term performance for customers experiencing average or better service;

    c) Improving service levels for customers experiencing below average service or who have special reliability needs (e.g. hospitals); and,

    d) Balancing other customer priorities (e.g. customer service) with the need to contain rate increases.

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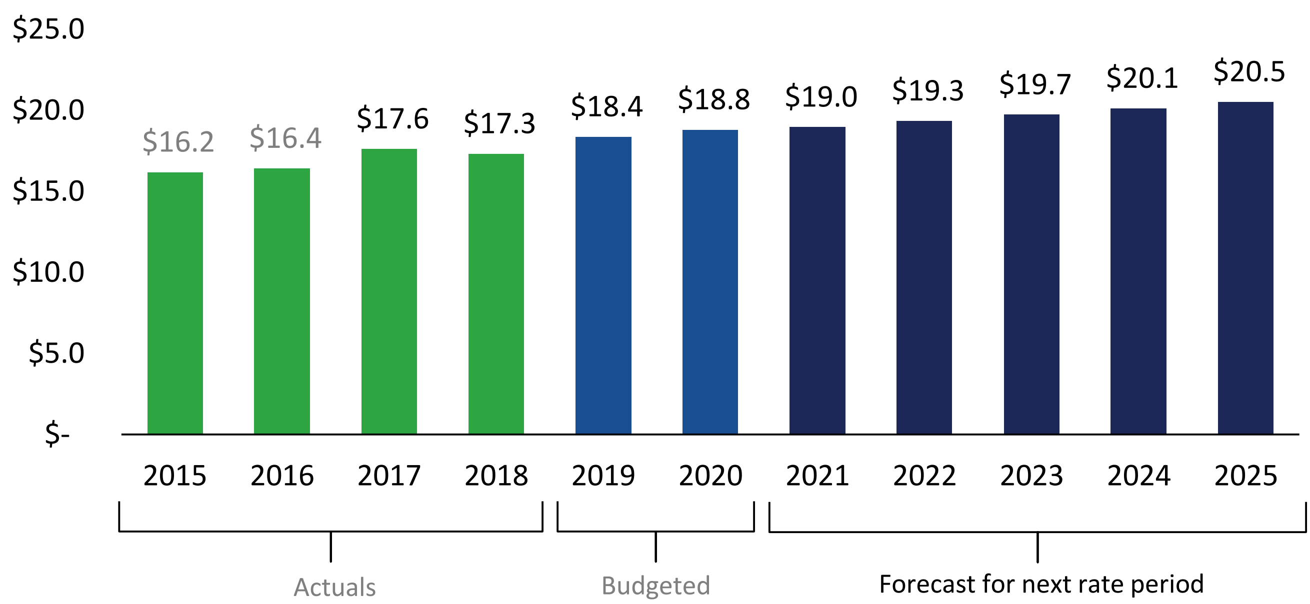
Niagara Peninsula Energy Background

Operating Expenses

In this section, we want to focus on operating expenses and how NPEI compares to its peers.

NPEI's operating budget covers recurring expenses, such as the maintenance of poles, wires, transformers, fleet and buildings as well as proactive maintenance programs such as tree trimming, and payroll for employees. Meter reading, postage, cyber security and hardware/software maintenance expenses are billing and customer service-related expenses. The proposed 5-year plan, between 2021 and 2025, would see NPEI spend an estimated total of $98.7 million on operations.

NPEI's Current and Forecasted Operating Expenses, per Year (Millions)*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

NPEI's **operating costs** are benchmarked by the OEB against other utilities in Ontario. In the last year of publicly available data collected by the OEB, NPEI's operating costs per customer was **$311.67**, which is slightly more than some, while less than both Hydro One and Canadian Niagara Power.

2018 Operating & Maintenance and Administration (OM&A) Per Customer ($)

The diverse geographical nature of NPEI's service territory, which is a mix of urban and rural communities is a large consideration/driver of these OM&A costs. In some parts of the service territory, there may be less than 30 customers per kilometer of line. Despite low density, these lines still require the same level of ongoing maintenance, including tree trimming and other expenses that contribute to operating the system; thereby resulting in a higher cost per customer.

Niagara Peninsula Energy Background

Operating Expenses

Recall, this customer feedback portal does not ask questions that expect you to be an electricity expert.

The OEB runs an open and transparent review process where experts from the OEB and intervenor groups review and challenge NPEI's analyses and assessments. You are welcome to participate in the OEB process if you are interested in those issues. Details can be found at oeb.ca/participate.

This customer engagement however, is focused on capital investments.

Detailed discussion of NPEI's operating budget is left to experts from the OEB and intervenors in the formal rate application review; this workbook focuses on collecting your view on competing trade-offs in capital investments.

Q5. Does leaving the detailed discussion about Niagara Peninsula Energy's operating budget to experts from the OEB and intervenors seem like the right approach or wrong approach to you?

- ☐ Definitely the right approach
- ☐ Probably the right approach
- ☐ Probably the wrong approach
- ☐ Definitely the wrong approach
- ☐ Don't know enough to say

Additional Feedback (Optional)

Q6. [If wrong approach] And why do you say leaving the detailed discussion about NPEI's operating budget to the OEB and intervenors is the wrong approach? [OPEN]

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Niagara Peninsula Energy Background

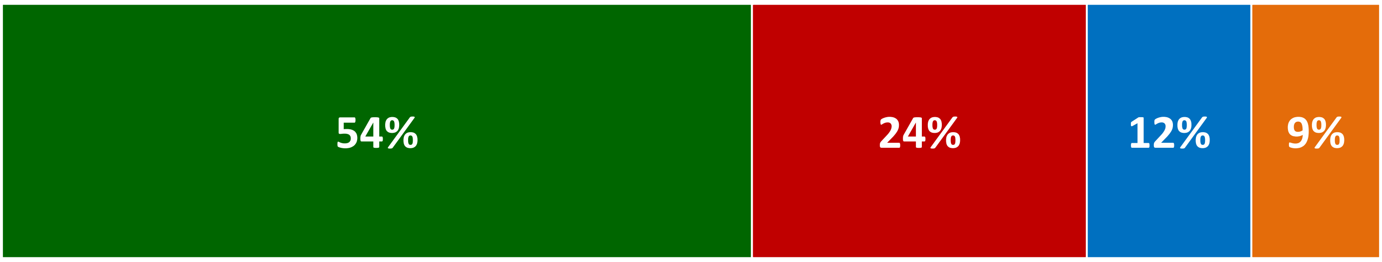
Capital Investments

NPEI's **capital budget** covers items that, once purchased, have lasting benefits over many years. Year-over-year, regardless of external drivers, NPEI will need to make investments in the core distribution system, including poles, wires, cables and transformers.

Based on initial customer input and the approach outlined previously, NPEI believes the capital expenditure required to address system renewal, maintain system reliability and safety, and invest in other infrastructure priorities between 2021 and 2025 is estimated to be **$70.3 million**.

NPEI classifies the costs of four types of capital investment between 2021 and 2025. Each of these four investment categories helps NPEI pace and prioritize projects.

2021-2025 Forecasted Capital Investments



System Renewal ($38.2 million)

These projects are a mix of planned end-of-life replacements and emergency replacements.

Projects Include: Replacement of existing overhead wires, poles, and pole mounted transformers, underground cables and transformers and transformer station upgrades.

System Access ($17.1 million)

"Must do" investments that respond to customer requests for new connections or new infrastructure development.

Projects Include: NPEI's share of new subdivisions, new upgraded commercial and industrial services, and relocating assets based on road infrastructure needs.

General Plant ($8.4 million)

These are investments needed to support the distribution system, such as tools, vehicles, buildings, and computers.

Projects Include: Financial and customer IT systems, enhanced cyber security investments, facility renovations, backup generation, and vehicle replacements.

System Service ($6.6 million)

These investments consist of projects that address capacity constraints, improve system reliability and customer service.

Projects Include: Installation of automated switches and system expansion to supply new development.

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Niagara Peninsula Energy Background

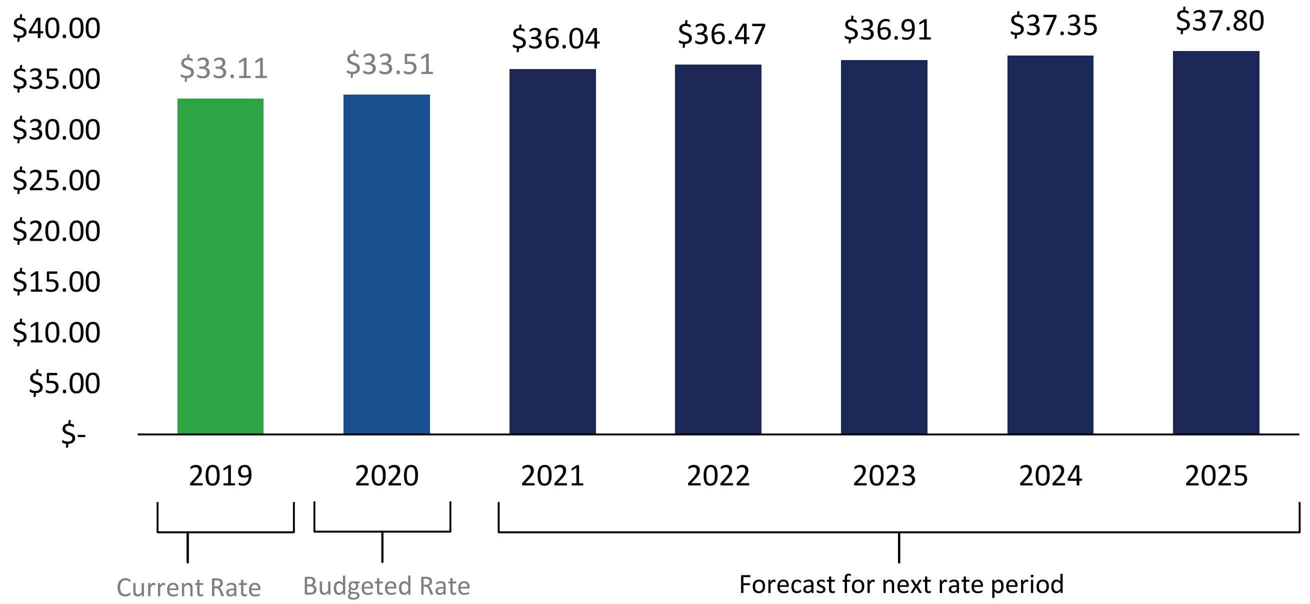
How much will this draft plan cost me?

Remember, the current typical NPEI residential customer's electricity bill is about $113 per month, of which $33.11 goes to NPEI.

It is estimated that if NPEI continues with its preliminary plan, the distribution portion of the bill will increase by $2.53 per month in 2021, when the plan is set to come into effect. For the period 2022-2025, the annual bill increase is limited by the OEB to be less than the rate of inflation.

- At the end of the 5-year plan, the typical residential customer would see the distribution portion of their electricity bill increase by $4.29.
- As a result, the distribution charges on the typical residential customer's monthly bill would increase from $33.51 in 2020 to $37.80 by 2025.

Estimated Residential Monthly Distribution Charge, per Year*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

NPEI is looking for your input on its preliminary plan to ensure it is making the spending decisions that matter to you, the customer.

The following sections of this workbook will explore some of the choices Niagara Peninsula Energy needs to make to help finalize its preliminary plan.

Niagara Peninsula Energy Customer Engagement

Planning for the Future: 2021-2025 Rate Application

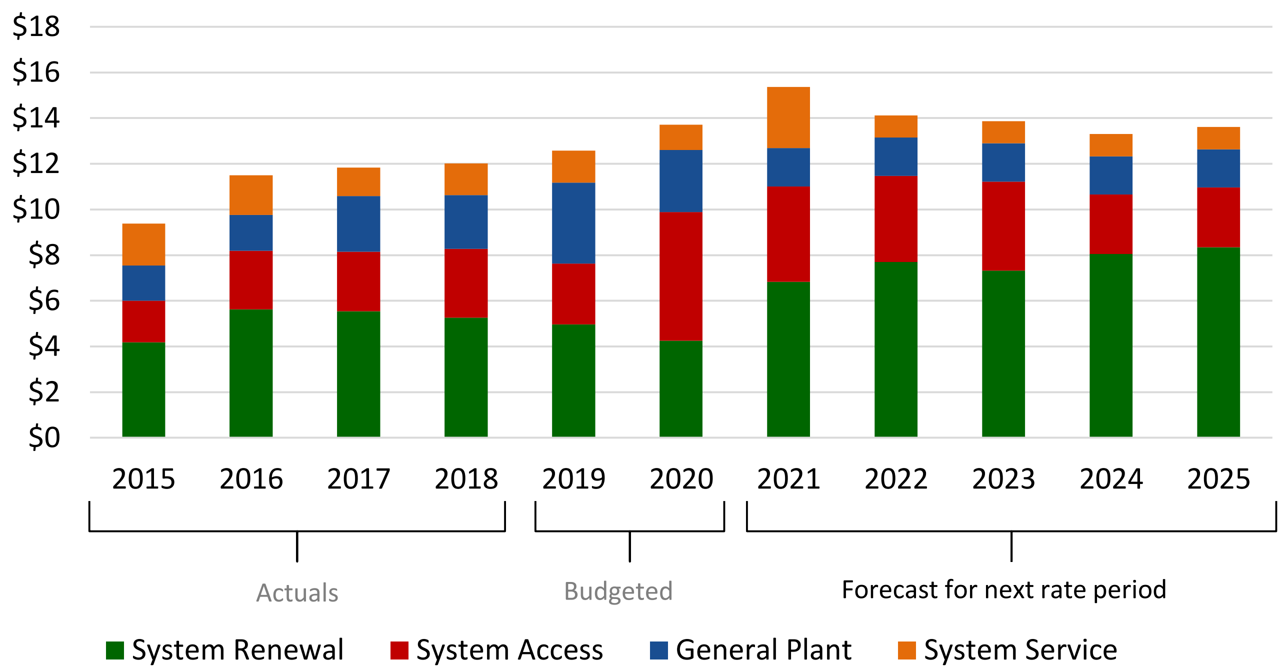
Niagara Peninsula Energy Background

Pacing Capital Investments

The overall amount NPEI invests in capital projects remains generally the same year over year, but what does change is where these investments are made. In some years, when unplanned or unforeseen investments are needed, NPEI will re-allocate funds to make room for these projects within the approved budget. This helps limit the overall amount that the distribution charges fluctuate year-over-year.

The chart below outlines NPEI's spending in past years, and proposed spending for the 5-year period 2021 to 2025.

2015 – 2025 Historical and Forecasted Capital Investments*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

System Access expenditures are budgeted to increase to $5.6M in 2020 to accommodate a number of large commercial customer growth projects as well as municipal road work.

Q7. Which of the following statements best represents your point of view regarding Niagara Peninsula Energy's approach to pacing investments?

- ☐ Niagara Peninsula Energy should keep spending levels consistent year-over-year, even if that means deferring investments to other years to lessen the impact of any bill increase.
- ☐ Niagara Peninsula Energy should not defer investments, even if that means larger bill increases in some years.
- ☐ Don't know

Additional Feedback (Optional)

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Niagara Peninsula Energy Background

Mandatory Investments

Federal, provincial, and municipal governments as well as regulators set requirements and standards that NPEI must satisfy. Mandatory investments can be broken down into three categories:

- **Connecting customers**: This includes connecting customers to the grid when a new home or building is constructed or modified.
- **Moving equipment**: This includes moving equipment like poles and cables for road widening.
- **Mandated obligations**: This includes installing and maintaining customer meters and transferring electricity from the provincial transmission system.

These mandatory investments mean that about **one-in-four dollars (23%)** of your distribution rates over the past five years have not been available for other non-mandatory investments. Looking forward to the 2021-2025 period, NPEI forecasts a similar level of mandatory investments, driven largely by:

- **Preparing to connect the new Niagara South hospital;**
- **Work to accommodate the 2021 Canada Summer Games in the Niagara Region, and;**
- **Work to accommodate growth and future electricity capacity needs.**

Q8. Which of the following statements best represents your point of view regarding Niagara Peninsula Energy's approach to mandatory and non-mandatory spending?

□ When Niagara Peninsula Energy encounters unforeseen increases in mandatory requirements, planned non-mandatory expenditures should be deferred to keep rate impacts down, even if that could result in a potential decline in service in the near future.

□ When Niagara Peninsula Energy encounters unforeseen increases in mandatory requirements, it should not defer planned non-mandatory expenditures, even if that could result in cost increases to customers over the next five years.

□ Don't know

Additional Feedback (Optional)

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Making Choices (1 of 7)

Overhead Pole Replacement

A recent asset health condition assessment shows that **575 or approximately 3%** of the poles in NPEI's distribution system are in *poor* or *very poor* condition. Each year, new poles enter this condition, and NPEI takes an approach that proactively replaces poles as to not create a large backlog. As a general rule, pole failure only causes an outage when something happens outside of the utility's control, most frequently due to trees knocking them down or a car accident.

On average, since 2014, NPEI has replaced approximately 88 poles per year. This pace has effectively maintained reliability over this period.

NPEI is proposing to replace most of these 575 poles in poor and very poor condition over the course of the next five years, however, there is an opportunity to replace these poles more quickly or slowly. NPEI must continue to invest in overhead pole replacement, therefore, this is a matter of whether customers would rather pay more during the upcoming period, or push some level of investment beyond the next five years.

Q9. Which of the following options do you prefer?

Option	Poles Replaced	Expected Outcome
Accelerated Pace ***Additional*** *$0.03 per month annually ($0.36 more per year)*	1,000 by 2025 (200 per year)	Address the very poor and some of the poor condition poles identified in the Asset Condition Assessment.
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	500 by 2025 (100 per year)	Address most of the very poor condition poles identified in the Asset Condition Assessment and annual pole inspections by 2025.
Slower Pace ***Decrease*** *of $0.01 per month annually ($0.12 less per year)*	250 by 2025 (50 per year)	Address only the poles in need of immediate replacement, as identified in the annual pole inspection report.

Additional Feedback (Optional)

Making Choices (2 of 7)

Overhead transformer replacement

Transformers are a critical piece of distribution equipment that reduce voltage from the higher levels that are more efficient to move electricity long distances to lower levels that are safer to connect to homes and businesses. They are typically either located on the ground, in underground vaults, or attached to distribution poles

A recent asset health condition assessment shows that **1,251 or approximately 21%** of the overhead transformers in NPEI's distribution system are in poor or very poor condition.

Since 2014, overhead transformer failure has directly resulted in approximately 15 outages per year. That said, in most cases, when an overhead transformer fails, it only impacts a small amount of customers and the equipment can be replaced within 2-3 hours depending on the circumstances.

However, when these outages do occur, it can take NPEI crews an extended period of time to replace the cable and restore power to affected households and businesses.

NPEI is proposing a new program to proactively replace **250 of the 677 or 37%** of the overhead transformers identified as very poor condition before they fail over the course of the next five years.

As with distribution poles, NPEI will proactively invest in overhead transformer replacement, therefore, this is a matter of whether customers would rather pay more during the upcoming period, or push some level of investment beyond the next five years.

Q10. Which of the following options do you prefer?

Option	Transformers Replaced	Expected Outcome
Accelerated Pace ***Additional*** *$0.01 per month annually ($0.12 more per year)*	375 by 2025 (75 per year)	Address some of the polemount transformers identified as very poor in the Asset Condition Assessment report.
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	250 by 2025 (50 per year)	Address some of the polemount transformers identified as very poor in the Asset Condition Assessment report.
Slower Pace ***Decrease*** *of $0.01 per month annually ($0.12 less per year)*	125 by 2025 (25 per year)	Address only the worst of the polemount transformers identified as very poor in the Asset Condition Assessment report.
Additional Feedback (Optional)		

Making Choices (3 of 7)

Converting Outdated Underground Kiosk Transformers

NPEI's system features a type of underground transformer that was popular in the 1940s to 1970s which no longer meets construction and safety standards. While this equipment still functions, it is becoming increasingly difficult to safely and effectively maintain. When this equipment does fail, it can result in lengthy outages due to the limited accessibility due to the original method of construction.

On average, since 2014, NPEI has converted approximately 9 kiosk transformers per year. Between 2018 and 2019, the pace of this program has been pushed off, and today, there remains 75 transformers in need of replacement.

NPEI is proposing to convert all of this equipment within the next seven years, with 55 being converted in the next five year period. That said, there is an opportunity to convert these kiosk transformers more slowly.

Q11. Which of the following options do you prefer?

Option	Transformers Installed	Expected Outcome
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	55 by 2025 (11 per year)	Work towards eliminating all old installations over the next 7 years.
Reduced Pace ***Decrease*** *of $0.02 per month annually ($0.24 less per year)*	25 by 2025 (5 per year)	Work towards eliminating all old installations over the next 15 years.
Slower Pace ***Decrease*** *of $0.03 per month annually ($0.36 less per year)*	10 by 2025 (2 per year)	Work towards eliminating all old installations over the next 35 years.

Additional Feedback (Optional)

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Making Choices (4 of 7)

Underground cable replacement

Many neighbourhoods across NPEI's service territory are serviced by underground cables. Historically, NPEI has taken a "run-to-failure" approach with this equipment; that is, a cable will be replaced only once it has failed. The age of this equipment is now becoming a concern, with approximately 78 km or 18% of underground cable operating beyond its estimated useful life of 35 years.

Since 2014, underground cable failure has directly resulted in approximately ten outages per year, and when these outages do occur, it can take NPEI crews an extended period to replace the cable and restore power to affected households and businesses.

Between 2021 and 2025, NPEI is proposing a new program that will replace cable that has been identified as past end of life when completing other associated work. NPEI believes that this could help reduce the number and length of outages caused by underground cable failure, as well as to start getting ahead of the ongoing age issue. That said, there is an opportunity to take a more proactive approach to addressing some of the older cable in the system.

Q12. Which of the following options do you prefer?

Option	Km of cable installed	Expected Outcome
Further Accelerated Pace ***Additional*** *$0.13 per month annually ($1.56 more per year)*	24 km by 2025 (4.8 km per year)	Proactively replace more of the cables identified as past end of life in the Asset Condition Assessment Report.
Accelerated Pace ***Additional*** *$0.06 per month annually ($0.72 more per year)*	12 km by 2025 (2.4 km per year)	Proactively replace some of the cables identified as past end of life in the Asset Condition Assessment Report.
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	2 km by 2025 (0.4 km per year)	Replace cables past end of life as other work is being completed on associated switchgear or riser poles.

Additional Feedback (Optional)

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Making Choices (5 of 7)

Subdivision underground rehabilitation

71 of the subdivisions in NPEI's service territory were constructed with **direct buried cable** which refers to a type of construction where cables are laid directly in underground trenches without a protective barrier.

While this was typical construction at the time, 40 of these subdivisions were built 40 or more years ago, and the cables are now approaching the end of their recommended life.

In this upcoming plan, NPEI is proposing a new program to start preparing to upgrade the service in the subdivisions with the most pressing needs.

In order to keep costs down, NPEI is proposing to start rehabilitation of the underground "system" by installing ducts that will eventually carry underground cables over the next five years. The cables would be installed as needed (upon failure) or once all of the old subdivisions have had the duct installed.

Completing this work in two phases will not only save costs now, but also help ensure that NPEI will be able to rehabilitate the most subdivisions in the shortest time.

Between 2021 and 2025, NPEI is proposing a new program that will proactively install ducts in approximately 10 subdivisions. Which subdivisions receive investment first will predominantly be based on age. That said, there is an opportunity to either accelerate or slow down the pace of this new program.

Q13. Which of the following options do you prefer?

Option	Km of vault installed	Expected Outcome
Accelerated Pace ***Additional*** *$0.02 per month annually ($0.24 more per year)*	30 km by 2025 (6 km per year)	Install 6 km of ducts or approximately four subdivisions per year.
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	15 km by 2025 (3 km per year)	Install 3 km of ducts or approximately two subdivisions per year.
Slower Pace ***Decrease*** *of $0.01 per month annually ($0.12 less per year)*	7.5 km by 2025 (1.5 km per year)	Install 1.5 km of ducts or approximately one subdivision per year.
Additional Feedback (Optional)		

Making Choices (6 of 7)

Overhead rebuilds

Beyond replacing overhead poles, NPEI has a program that rebuilds the overhead system for entire streets and neighbourhoods. This includes poles, wires, and all other equipment that goes into operating the overhead system.

A recent asset health condition assessment identified a total of **60 areas** within NPEI's service territory that require complete overhead rebuilds**.** Most of this equipment is either beyond its recommended age or deteriorated due to weather and other factors. This infrastructure is in addition to the poles identified in the earlier section.

This program is intended to contribute to the "betterment" of the overhead system by;

- Improving system performance by installing animal guards and higher capacity transformers to reduce the likelihood of outages, and;
- Improving system aesthetics with new and taller poles.

On average, each of the projects would replace approximately 30-40 poles, depending on the population density of the area being worked on. NPEI's current approach would rebuild **40 out of 60 areas** in the 2021 to 2025 period.

NPEI must continue to invest in overhead rebuilds, therefore, this is a matter of whether customers would rather pay more during the upcoming period or push some level of investment beyond the next five years.

Q14. Which of the following options do you prefer?

Option	Overhead rebuilds	Expected Outcome
Accelerated Pace ***<u>Additional</u>*** *$0.03 per month annually ($0.36 more per year)*	61 km by 2025 (12.2 km per year)	Rebuild 12.2 km per year or approximately 10 projects per year
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	48.5 km by 2025 (9.7 km per year)	Rebuild areas with assets that have been identified as very poor in Asset Condition Assessment. Rebuild 9.7 km per year or approximately 8 projects per year
Slower Pace ***<u>Decrease</u>*** *of $0.03 per month annually ($0.36 less per year)*	36 km by 2025 (7.2 km per year)	Rebuild 7.2 km per year or approximately 6 projects per year
Additional Feedback (Optional)		

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Making Choices (7 of 7)

Grid modernization

New technology has changed the way that NPEI can manage and monitor the distribution system.

Supervisory Control and Data Acquisition (SCADA) systems allow NPEI staff the ability to remotely monitor and trace system faults and re-close switches from a control room rather than sending a repair crew to patrol the lines. These systems are particularly effective where there are larger distances between customers, for instance, in more rural areas of the western region of NPEI's service territory.

This equipment can have significant positive impacts on restoration times when an outage does occur, particularly in instances such as during a severe weather event.

Q15. Which of the following options do you prefer?

Option	Devices installed	Expected Outcome
Accelerated Pace ***Additional*** *$0.01 per month annually ($0.12 more per year)*	20 devices (4 per year)	NPEI to double installation rate to four devices per year.
Included in Draft Plan *Within proposed average 2.5% increase over 5-years*	10 Devices (2 per year)	Remain at current installation pace of two devices per year. Install new devices to expand NPEI's Smart Grid network. These devices provide better monitoring capability on the system, which leads to improved restoration times during outages.
Slower Pace ***Decrease*** *of $0.005 per month annually ($0.06 less per year)*	5 Devices (1 per year)	NPEI to cut rate of installation in half to one device per year.
Additional Feedback (Optional)		

Niagara Peninsula Energy Customer Engagement

Planning for the Future: 2021-2025 Rate Application

Impact of Choices

Investment Alternative Summary

Throughout this workbook, you have been asked about **seven key choices** that could impact your rates. Below is a summary of your answers to the questions that could impact your rates.

At the bottom of this page you will find the total bill impact of all the answers.

Having seen the total bill impact, please review your answers and change your responses if you desire; your potential rate impact will be re-calculated. You will have the opportunity to continue adjusting your answers until you feel you've reached the best balance for you.

Overhead pole replacement

- ☐ **Accelerated Pace**: Additional $0.03 per month annually ($0.36 more per year annually)
- ☐ **Included in Draft Plan**: Within proposed average 2.5% increase over 5-years
- ☐ **Slower Pace**: Decrease of $0.01 per month annually ($0.12 less per year)

Note: these areas will be uniquely populated for each individual customer. The bill impacts of their individual responses will be summed and displayed below.

The total impact of your choices would result in:

+/- $X.XX per month annually (+/- $X.XX per year)

This is in addition to the estimated 2.5% annual increase if Niagara Peninsula Energy continues with its current draft plan.

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Impact of Choices

Assessing Niagara Peninsula Energy's draft 2021-2025 plan

Again, it is estimated that if NPEI continues with its preliminary plan, the distribution portion of the bill will increase by $2.53 per month in 2021, when the plan is set to come into effect. For the period 2022-2025, the annual bill increase is limited by the OEB to be less than the rate of inflation.

- At the end of the 5-year plan, the typical residential customer would see the distribution portion of their electricity bill increase by $4.29.
- As a result, the distribution charges on the typical residential customer's monthly bill would increase from $33.51 in 2020 to $37.80 by 2025.

Estimated Typical Residential Annual Increase in Monthly Bill (5 year forecast)

	Year	Average Residential Bill	Distribution Portion of Bill	Incremental Rate Change	% Change * (on distribution portion of bill)
Current Rate	2019	$113.32	$33.11		
Budgeted Rate	2020	$115.03	$33.51	$0.40	1.21%
Forecast for next rate period	2021	$116.33	$36.04	$2.53	7.55%
	2022	$118.08	$36.47	$0.43	1.20%
	2023	$119.85	$36.91	$0.44	1.20%
	2024	$121.65	$37.35	$0.44	1.20%
	2025	$123.47	$37.80	$0.45	1.20%
				$4.29	

*** These estimates are preliminary, and are subject to your feedback as the business plan is finalized .**

Q16. Considering what you know about Niagara Peninsula Energy's draft plan – which would see the typical residential customer's distribution portion of their bill increase by $4.29 over the 5-year period – which of the following best represents your point of view?

- ☐ NPEI should improve service, as discussed on the previous pages, even if that means an increase that exceeds $4.29 over the 5-year period
- ☐ 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.
- ☐ NPEI should keep increases below $4.29, even if that could mean reductions in service over the 5-year period.
- ☐ Other [Please specify]
- ☐ Don't know

Q17. Thinking about your answer to the previous question, why do you feel that NPEI should take that approach over the 2021-2025 period? (Optional) [OPEN]

Q18. Do you have any final comments regarding NPEI or the customer engagement that you just completed? (Optional) [OPEN]

About you

More about you

The following questions are for statistical purposes only. This information is used to segment and group similar people together when the survey results are analysed.

Q19. To the best of your knowledge, does your home receive electrical service via overhead wires, underground cables?

- Overhead wires
- Underground cables
- Don’t know

Q19b. Have you experienced any power outages at your home or at your business in the past 12 months which lasted longer than one minute?

- No outages
- 1 outage
- 2 outages
- 3 or more outages
- Don’t know

To what extent do you agree or disagree with the following statements?

Q20. The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.

- Strongly agree
- Somewhat agree
- Somewhat disagree
- Strongly disagree
- Don’t know/No opinion

Q21. Customers are well served by the electricity system in Ontario.

- Strongly agree
- Somewhat agree
- Somewhat disagree
- Strongly disagree
- Don’t know/No opinion

About you

More about you

Q22. Which gender identity do you most closely identify with?

- Male
- Female
- Not listed (Please specify)
- Prefer not to say

Q23. What age category do you fall into?

- Under 18
- 18-24
- 25-34
- 35-44
- 45-54
- 55-64
- 65-74
- 75 or older
- Prefer not to say

Q24. Including yourself, how many people live in your household?

- Single person household
- 2 people
- 3 people
- 4 people
- 5 of more people
- Prefer not to say

Q25. Which of the following categories best describes the total annual income, after taxes, of all the members of your household?

- Less than $28,000
- $28,000 to less than $39,000
- $39,000 to less than $48,000
- $48,000 to less than $52,000
- $52,000 or more
- Prefer not to say

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Final Thoughts

Feedback on Niagara Peninsula Energy's Consultation

Niagara Peninsula Energy values your feedback. This is the first time the utility has conducted a review about its upcoming plans in this type of format.

Q26. Overall, did you have a favourable or unfavourable impression of the consultation you just completed?

- o Very favourable
- o Somewhat favourable
- o Somewhat unfavourable
- o Very unfavourable
- o Don't know

Q27. In this consultation, do you feel that NPEI provided too much information, not enough, or just the right amount?

- o Too little information
- o Just the right amount of information
- o Too much information

Q28. Was there any content missing that you would have liked to have seen included in this consultation?

- o None

Q29. Is there anything that you would still like answered?

- o None

Appendix 1-26

Small Business Customer Engagement Workbook

Customer Engagement

Workbook

Small Business Workbook

November 2019

STRICTLY PRIVILEGED AND CONFIDENTIAL

About this Consultation

Welcome to Niagara Peninsula Energy's Customer Engagement!

Niagara Peninsula Energy (NPEI) needs your input on choices that will impact the services you receive and the rates that you pay.

- **NPEI** is developing its investment plan for 2021 to 2025. This plan will determine the investments NPEI will make in equipment and infrastructure; the services it provides; and the rates you pay.
- As **NPEI** plans for the future, they want to ensure their business decisions are aligned with customers priorities, preferences, and needs.
- Throughout this survey, information will be provided in an effort to give you more background on which to base your responses.
- While responding to the following questions, remember that there are no wrong answers, and that your individual responses will remain anonymous.
- This customer engagement will take approximately 25-35 minutes to complete, depending on the level of feedback you wish to provide. Your progress will be saved as you move through the workbook, meaning you can leave and return to the customer engagement at any time.

All individual responses will be kept confidential. Innovative Research Group (INNOVATIVE), an independent research company, has been hired NPEI to gather your feedback.

Those who complete the questions that follow will be invited to enter a draw to win one (1) $500 cash prize.

About this Consultation

Thank you for your interest in being a part of Niagara Peninsula Energy's customer engagement.

If you are reading this on a smaller mobile device, you may want to consider accessing the survey from a tablet, desktop or laptop instead so that it is easier for you to read.

Would you like to complete this survey on behalf of your business/organization, or your home?

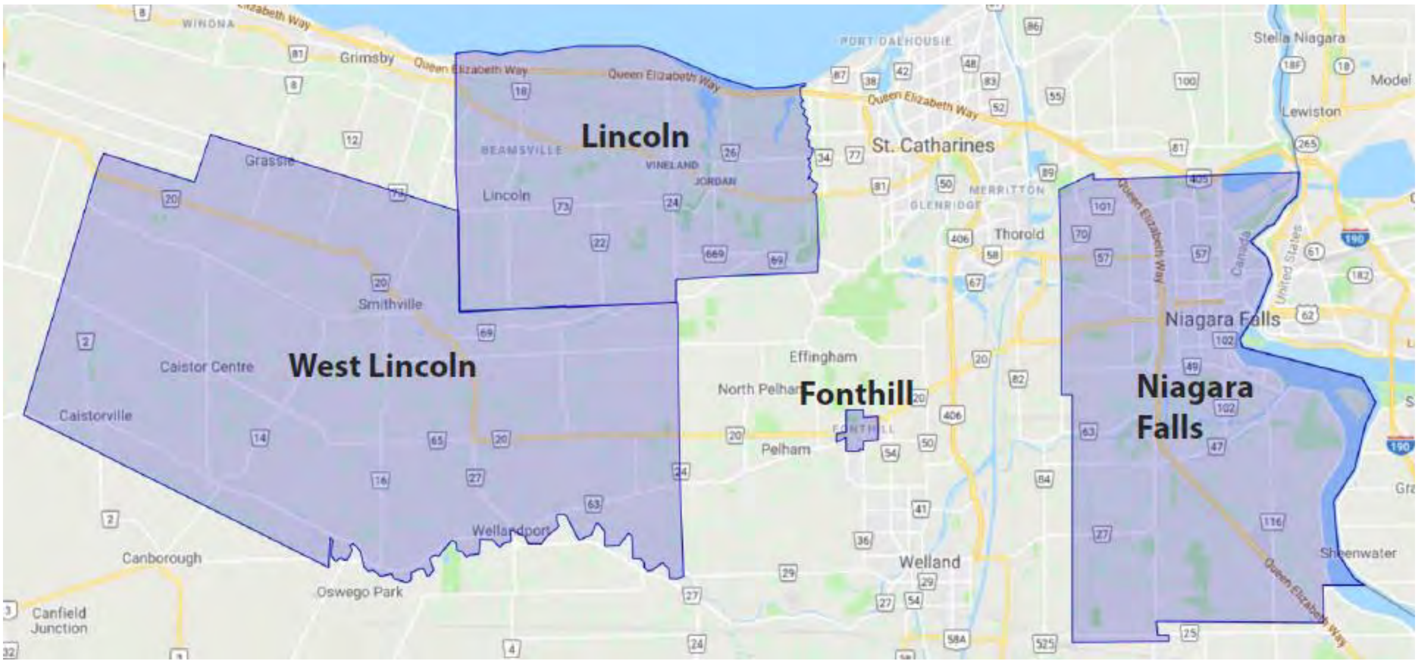
- Business/organization
- Home

Electricity 101

Who is Niagara Peninsula Energy?

NPEI provides local electricity distribution and related services to residential and business customers in the City of Niagara Falls, Town of Lincoln, Town of Pelham, and Township of West Lincoln.

- NPEI serves an area of approximately 827 square kilometers and 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 local distribution company (LDC) and regulated entity, NPEI applies for, and receives approval from the regulator to charge for its services.



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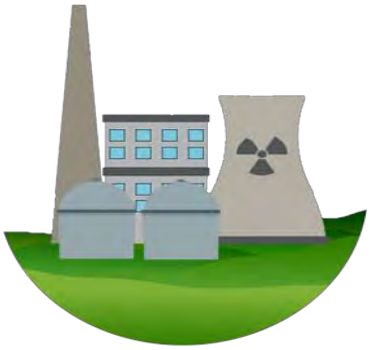
Electricity 101

Niagara Peninsula Energy's Role in Ontario's Electricity System

Ontario's electricity system is owned and operated by public, private, and municipal corporations across the province. It is made up of three key components: **generation**, **transmission** and **distribution**.

Generation

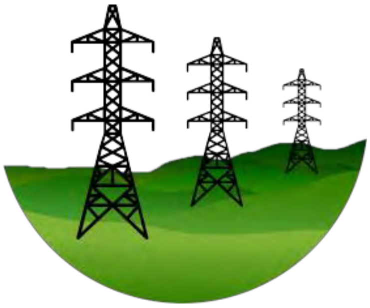
Where electricity comes from



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.

Transmission

How electricity travels across Ontario



Once generated, electricity must be transported to electrical substations 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 kilometres of 'electricity highway', most of which is owned and operated by Hydro One.

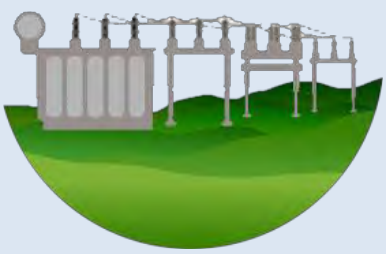
Local Distribution

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. This local distribution system includes transformer stations that decrease the voltage of the electricity so it can be used safely in your home or business.

There are approximately 1,451 km of overhead power lines and 573 km of underground cable. Through this distribution network, NPEI delivers electricity to approximately 55,600 residential and business customers.

Niagara Peninsula Energy Inc. is jointly owned by the **City of Niagara Falls**, the **Town of Lincoln**, the **Town of Pelham** and the **Township of West Lincoln**.



Q1. Before this survey, how familiar were you with Niagara Peninsula Energy, which operates the electricity distribution system in your community?

- ☐ Very familiar
- ☐ Somewhat familiar
- ☐ Not familiar at all
- ☐ Don't know

Electricity 101

How much of my electricity bill goes to Niagara Peninsula Energy?

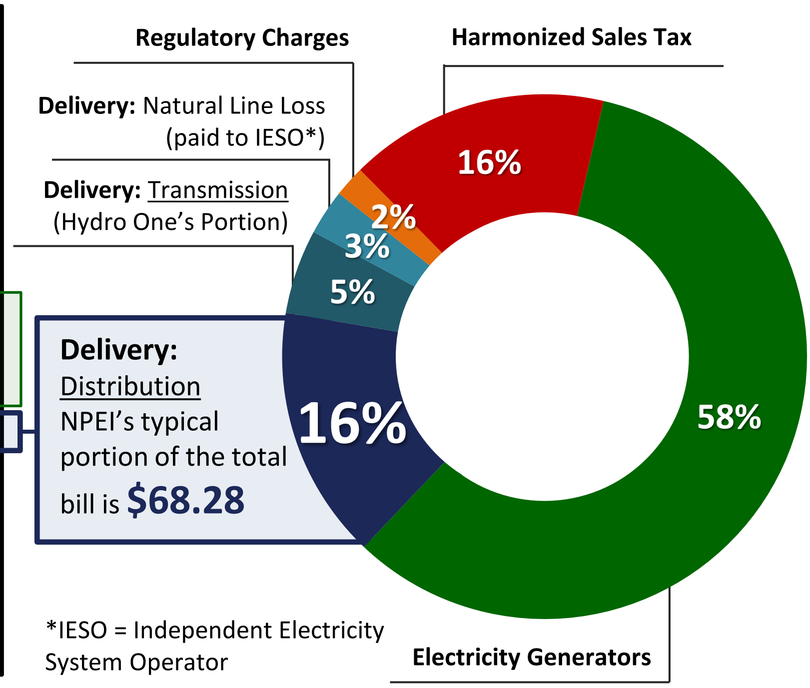
- Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board (OEB), the provincial energy regulator.
- While NPEI is responsible for collecting payment for the entire electricity bill, it retains only the distribution portion of the delivery charge.
- Distribution makes up about **16%** of the typical small business customer's bill.
- The rest of your bill is passed onto provincial transmission companies, power generation companies, the government and regulatory agencies.

NPEI Sample Monthly Bill*
(Based on monthly usage of 2,000 kWh)

Account Number:
000 000 000 000 0000

Meter Number:
00000000

Your Electricity Charges	
Electricity	
Off-Peak @ 10.1 ¢/kWh	129.28
Mid-Peak @ 14.4 ¢/kWh	51.84
On-Peak @ 20.8 ¢/kWh	74.88
Delivery	103.35
Regulatory Charges	8.42
Total Electricity Charges	$367.77
HST	47.81
Ontario Electricity Rebate*	(-$116.95)
Total Amount	$298.63



*IESO = Independent Electricity System Operator

* As of November 1, 2019. Chart is based on total bill amount after applying the Ontario Electricity Rebate.

Q2. Thinking specifically about the services provided to you and your community by Niagara Peninsula Energy, overall, how satisfied or dissatisfied are you with the services that your organization receive?

- ☐ Very satisfied
- ☐ Somewhat satisfied
- ☐ Neither satisfied nor dissatisfied
- ☐ Somewhat dissatisfied
- ☐ Very dissatisfied
- ☐ Don't know

Q3. Before this survey, how familiar were you with the amount of your organization's electricity bill that went to Niagara Peninsula Energy?

- ☐ Very familiar
- ☐ Somewhat familiar
- ☐ Not familiar
- ☐ Don't know

Q4. Is there anything in particular you would like Niagara Peninsula Energy to do to improve its services to your organization?

Niagara Peninsula Energy Background

Building Niagara Peninsula Energy's draft plan

NPEI has put together its draft business plan based on the information and input from various sources, such as:

- **Legal and regulatory** requirements by continuing to meet its obligations.
- **Internal business planning** based on expert analysis and professional judgment to develop construction and operations programs that address safety, business, technical, and operational needs.
- **Customer feedback** collected through both ongoing dialogues and specific engagements, such as this.

There are three key organizations responsible for setting the policy direction of Ontario's electricity system. The decisions made by these organizations impact how utilities operate their businesses and serve their customers.

- **Policy**: The Ontario Ministry of Energy, Northern Development and Mines (MNDM) creates energy policy for the province.
- **Regulation**: The electricity industry in Ontario is regulated by the Ontario Energy Board (OEB). One of the OEB's roles is to review the business and distribution plans of all electricity distributors and approve the rates that they charge customers.
- **Operations and Planning**: The Independent Electricity System Operator (IESO) manages the provincial electricity grid, plans for the province's future energy needs, and develops conservation programs.

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Niagara Peninsula Energy Background

How did customer feedback shape Niagara Peninsula Energy's draft plan?

NPEI is placing more emphasis on incorporating customer feedback into the planning process than ever before.

NPEI engages with its customers both in day-to-day interactions and in a variety of customer engagement activities. These interactions help identify customer needs and preferences, and inform how the utility plans for the future.

This past summer, NPEI engaged with **thousands of residential and business customers** from across its service territory – both in person and through telephone and online surveys.

What did NPEI hear from customers like yourself?

1. The clear majority of NPEI residential and small business customers are satisfied with the current service they receive. When asked how NPEI can improve service, top responses for residential customers were "nothing", followed by "lower or reduce rates".

2. Among competing outcomes, **price**, **reliability**, and **finding internal cost efficiencies** are the top three priorities for both residential and small business customers.

3. While keeping price at a reasonable and affordable level is an important priority, many customers feel that investing in the grid to maintain reliability, is preferable to deferring investments to keep bills low.

Considering this feedback, as well as the information and inputs discussed on the previous page, NPEI has developed a draft plan that is responsive to:

1. Legal requirements by continuing to meet its obligations, including safety and reliability;

2. A transformer station upgrade to accommodate the new Niagara South Hospital and future surrounding growth.

3. Mandatory service connections to accommodate new customers and customer-required upgrades, of which NPEI does not have control over how and when these costs are incurred.

4. Customer feedback by:

    a) Keeping distribution price increases as low as possible;

    b) Maintaining long-term performance for customers experiencing average or better service;

    c) Improving service levels for customers experiencing below average service or who have special reliability needs (e.g. hospitals); and,

    d) Balancing other customer priorities (e.g. customer service) with the need to contain rate increases.

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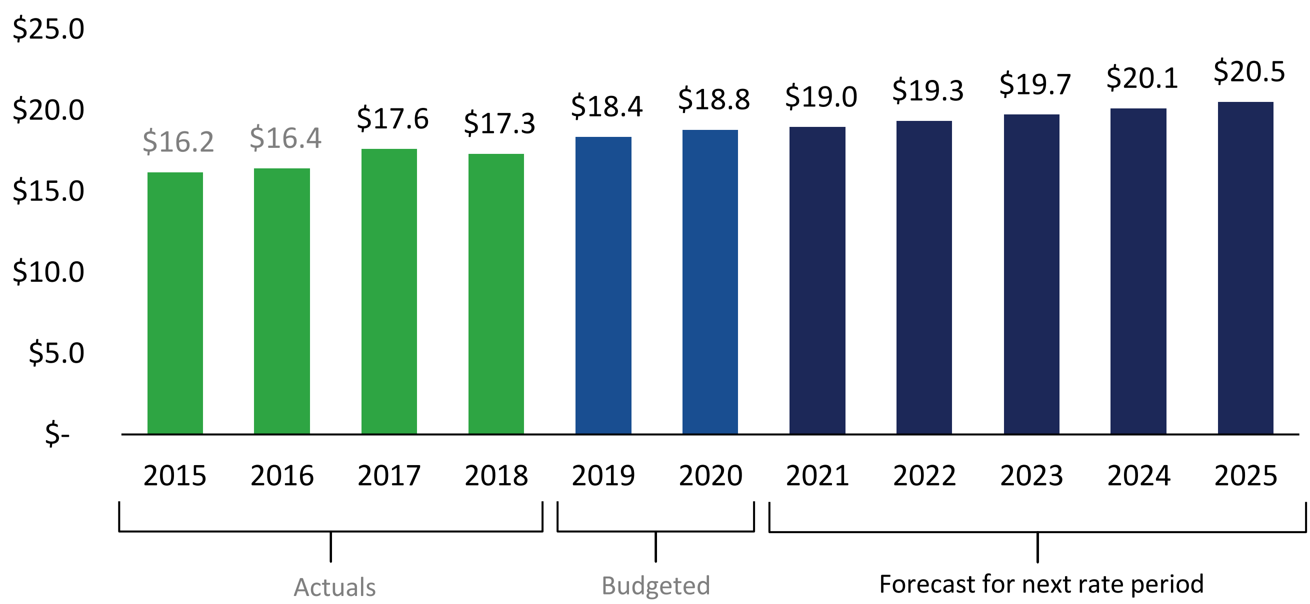
Niagara Peninsula Energy Background

Operating Expenses

In this section, we want to focus on operating expenses and how NPEI compares to its peers.

NPEI's operating budget covers recurring expenses, such as the maintenance of poles, wires, transformers, fleet and buildings as well as proactive maintenance programs such as tree trimming, and payroll for employees. Meter reading, postage, cyber security and hardware/software maintenance expenses are billing and customer service-related expenses. The proposed 5-year plan, between 2021 and 2025, would see NPEI spend an estimated total of $98.7 million on operations.

NPEI's Current and Forecasted Operating Expenses, per Year (Millions)*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

NPEI's **operating costs** are benchmarked by the OEB against other utilities in Ontario. In the last year of publicly available data collected by the OEB, NPEI's operating costs per customer was **$311.67**, which is slightly more than some, while less than both Hydro One and Canadian Niagara Power.

2018 Operating & Maintenance and Administration (OM&A) Per Customer ($)

The diverse geographical nature of NPEI's service territory, which is a mix of urban and rural communities is a large consideration/driver of these OM&A costs. In some parts of the service territory, there may be less than 30 customers per kilometer of line. Despite low density, these lines still require the same level of ongoing maintenance, including tree trimming and other expenses that contribute to operating the system; thereby resulting in a higher cost per customer.

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Niagara Peninsula Energy Background

Operating Expenses

Recall, this customer feedback portal does not ask questions that expect you to be an electricity expert.

The OEB runs an open and transparent review process where experts from the OEB and intervenor groups review and challenge NPEI's analyses and assessments. You are welcome to participate in the OEB process if you are interested in those issues. Details can be found at oeb.ca/participate.

This customer engagement however, is focused on capital investments.

Detailed discussion of NPEI's operating budget is left to experts from the OEB and intervenors in the formal rate application review; this workbook focuses on collecting your view on competing trade-offs in capital investments.

Q5. Does leaving the detailed discussion about Niagara Peninsula Energy's operating budget to experts from the OEB and intervenors seem like the right approach or wrong approach to you?

- ☐ Definitely the right approach
- ☐ Probably the right approach
- ☐ Probably the wrong approach
- ☐ Definitely the wrong approach
- ☐ Don't know enough to say

Additional Feedback (Optional)

Q6. [If wrong approach] And why do you say leaving the detailed discussion about NPEI's operating budget to the OEB and intervenors is the wrong approach? [OPEN]

Niagara Peninsula Energy Background

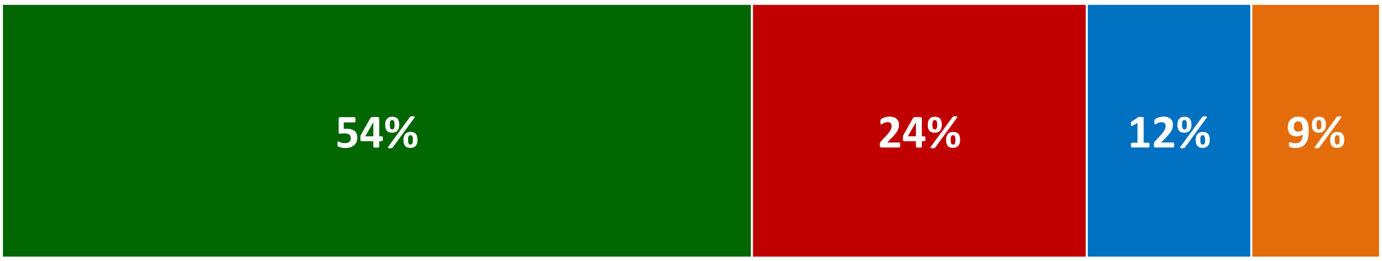
Capital Investments

NPEI's **capital budget** covers items that, once purchased, have lasting benefits over many years. Year-over-year, regardless of external drivers, NPEI will need to make investments in the core distribution system, including poles, wires, cables and transformers.

Based on initial customer input and the approach outlined previously, NPEI believes the capital expenditure required to address system renewal, maintain system reliability and safety, and invest in other infrastructure priorities between 2021 and 2025 is estimated to be **$70.3 million**.

NPEI classifies the costs of four types of capital investment between 2021 and 2025. Each of these four investment categories helps NPEI pace and prioritize projects.

2021-2025 Forecasted Capital Investments



System Renewal ($38.2 million)

These projects are a mix of planned end-of-life replacements and emergency replacements.

Projects Include: Replacement of existing overhead wires, poles, and pole mounted transformers, underground cables and transformers and transformer station upgrades.

System Access ($17.1 million)

"Must do" investments that respond to customer requests for new connections or new infrastructure development.

Projects Include: NPEI's share of new subdivisions, new upgraded commercial and industrial services, and relocating assets based on road infrastructure needs.

General Plant ($8.4 million)

These are investments needed to support the distribution system, such as tools, vehicles, buildings, and computers.

Projects Include: Financial and customer IT systems, enhanced cyber security investments, facility renovations, backup generation, and vehicle replacements.

System Service ($6.6 million)

These investments consist of projects that address capacity constraints, improve system reliability and customer service.

Projects Include: Installation of automated switches and system expansion to supply new development.

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Niagara Peninsula Energy Background

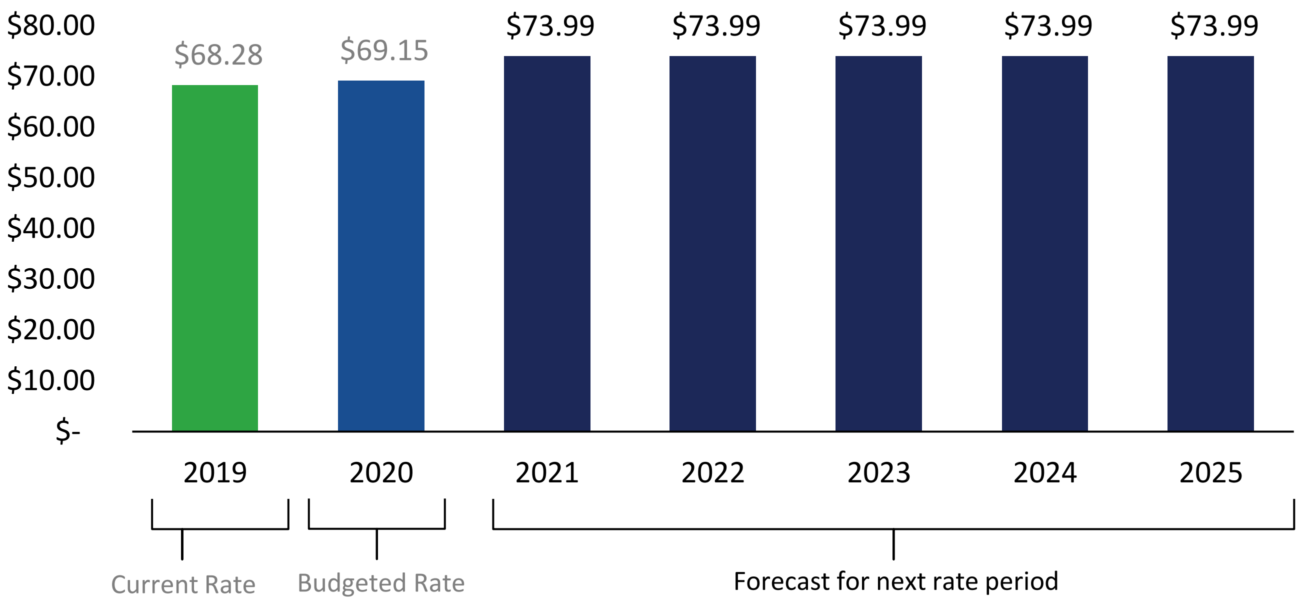
How much will this draft plan cost my organization?

Remember, the current typical NPEI small business customer's electricity bill is about $298 per month, of which $68.28 goes to NPEI.

It is estimated that if NPEI continues with its preliminary plan, the distribution portion of the bill will increase by $4.84 per month in 2021, when the plan is set to come into effect. For the period 2022-2025, the annual bill increase is limited by the OEB to be less than the rate of inflation.

- At the end of the 5-year plan, the typical small business customer would see the distribution portion of their electricity bill increase by $8.46.
- As a result, the distribution charges on the typical small business customer's monthly bill would increase from $69.15 in 2020 to $77.61 by 2025.

Estimated Small Business Monthly Distribution Charge, per Year*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

NPEI is looking for your input on its preliminary plan to ensure it is making the spending decisions that matter to you, the customer.

The following sections of this workbook will explore some of the choices Niagara Peninsula Energy needs to make to help finalize its preliminary plan.

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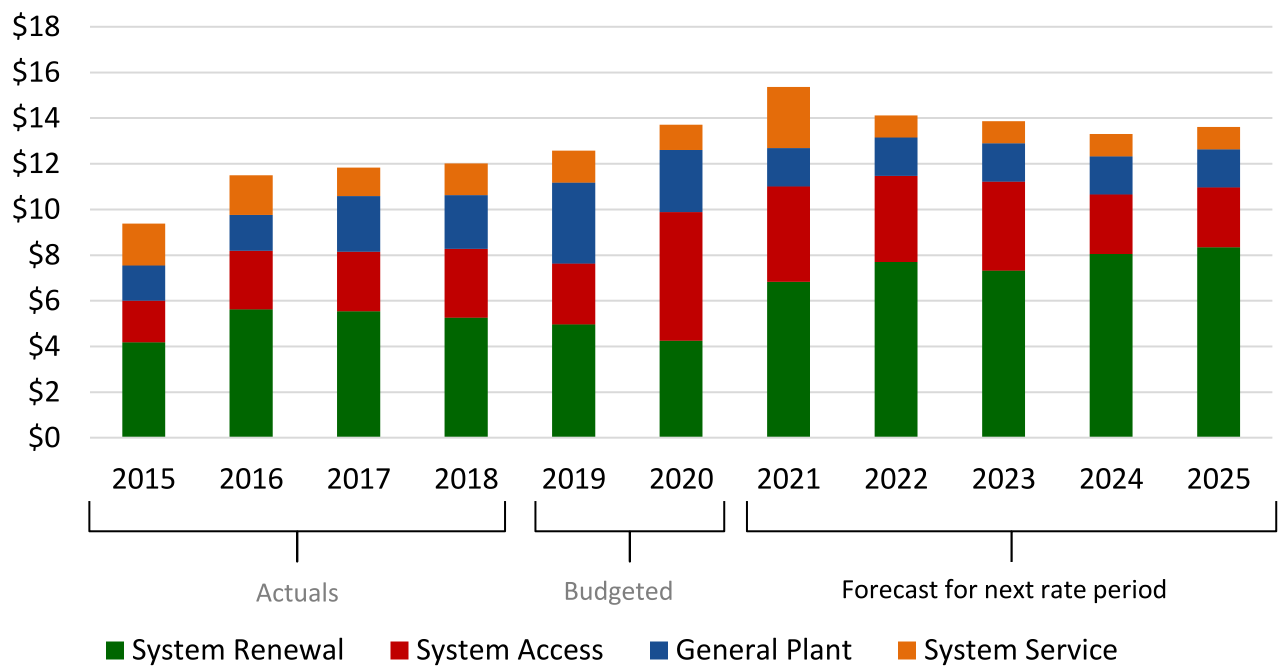
Niagara Peninsula Energy Background

Pacing Capital Investments

The overall amount NPEI invests in capital projects remains generally the same year over year, but what does change is where these investments are made. In some years, when unplanned or unforeseen investments are needed, NPEI will re-allocate funds to make room for these projects within the approved budget. This helps limit the overall amount that the distribution charges fluctuate year-over-year.

The chart below outlines NPEI's spending in past years, and proposed spending for the 5-year period 2021 to 2025.

2015 – 2025 Historical and Forecasted Capital Investments*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

System Access expenditures are budgeted to increase to $5.6M in 2020 to accommodate a number of large commercial customer growth projects as well as municipal road work.

Q7. Which of the following statements best represents your point of view regarding Niagara Peninsula Energy's approach to pacing investments?

- ☐ Niagara Peninsula Energy should keep spending levels consistent year-over-year, even if that means deferring investments to other years to lessen the impact of any bill increase.
- ☐ Niagara Peninsula Energy should not defer investments, even if that means larger bill increases in some years.
- ☐ Don't know

Additional Feedback (Optional)

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Niagara Peninsula Energy Background

Mandatory Investments

Federal, provincial, and municipal governments as well as regulators set requirements and standards that NPEI must satisfy. Mandatory investments can be broken down into three categories:

- **Connecting customers**: This includes connecting customers to the grid when a new home or building is constructed or modified.
- **Moving equipment**: This includes moving equipment like poles and cables for road widening.
- **Mandated obligations**: This includes installing and maintaining customer meters and transferring electricity from the provincial transmission system.

These mandatory investments mean that about **one-in-four dollars (23%)** of your distribution rates over the past five years have not been available for other non-mandatory investments. Looking forward to the 2021-2025 period, NPEI forecasts a similar level of mandatory investments, driven largely by:

- **Preparing to connect the new Niagara South hospital;**
- **Work to accommodate the 2021 Canada Summer Games in the Niagara Region, and;**
- **Work to accommodate growth and future electricity capacity needs.**

Q8. Which of the following statements best represents your point of view regarding Niagara Peninsula Energy's approach to mandatory and non-mandatory spending?

- ☐ When Niagara Peninsula Energy encounters unforeseen increases in mandatory requirements, planned non-mandatory expenditures should be deferred to keep rate impacts down, even if that could result in a potential decline in service in the near future.
- ☐ When Niagara Peninsula Energy encounters unforeseen increases in mandatory requirements, it should not defer planned non-mandatory expenditures, even if that could result in cost increases to customers over the next five years.
- ☐ Don't know

Additional Feedback (Optional)

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Making Choices (1 of 7)

Overhead Pole Replacement

A recent asset health condition assessment shows that **575 or approximately 3%** of the poles in NPEI's distribution system are in *poor* or *very poor* condition. Each year, new poles enter this condition, and NPEI takes an approach that proactively replaces poles as to not create a large backlog. As a general rule, pole failure only causes an outage when something happens outside of the utility's control, most frequently due to trees knocking them down or a car accident.

On average, since 2014, NPEI has replaced approximately 88 poles per year. This pace has effectively maintained reliability over this period.

NPEI is proposing to replace most of these 575 poles in poor and very poor condition over the course of the next five years, however, there is an opportunity to replace these poles more quickly or slowly. NPEI must continue to invest in overhead pole replacement, therefore, this is a matter of whether customers would rather pay more during the upcoming period, or push some level of investment beyond the next five years.

Q9. Which of the following options do you prefer?

Option	Poles Replaced	Expected Outcome
Accelerated Pace ***Additional*** *$0.03 per month annually ($0.36 more per year)*	1,000 by 2025 (200 per year)	Address the very poor and some of the poor condition poles identified in the Asset Condition Assessment.
Included in Draft Plan *Within proposed average 2.4% increase over 5-years*	500 by 2025 (100 per year)	Address most of the very poor condition poles identified in the Asset Condition Assessment and annual pole inspections by 2025.
Slower Pace ***Decrease*** *of $0.02 per month annually ($0.24 less per year)*	250 by 2025 (50 per year)	Address only the poles in need of immediate replacement, as identified in the annual pole inspection report.

Additional Feedback (Optional)

Making Choices (2 of 7)

Overhead transformer replacement

Transformers are a critical piece of distribution equipment that reduce voltage from the higher levels that are more efficient to move electricity long distances to lower levels that are safer to connect to homes and businesses. They are typically either located on the ground, in underground vaults, or attached to distribution poles

A recent asset health condition assessment shows that **1,251 or approximately 21%** of the overhead transformers in NPEI's distribution system are in poor or very poor condition.

Since 2014, overhead transformer failure has directly resulted in approximately 15 outages per year. That said, in most cases, when an overhead transformer fails, it only impacts a small amount of customers and the equipment can be replaced within 2-3 hours depending on the circumstances.

However, when these outages do occur, it can take NPEI crews an extended period of time to replace the cable and restore power to affected households and businesses.

NPEI is proposing a new program to proactively replace **250 of the 677 or 37%** of the overhead transformers identified as very poor condition before they fail over the course of the next five years.

As with distribution poles, NPEI will proactively invest in overhead transformer replacement, therefore, this is a matter of whether customers would rather pay more during the upcoming period, or push some level of investment beyond the next five years.

Q10. Which of the following options do you prefer?

Option	Transformers Replaced	Expected Outcome
Accelerated Pace ***Additional*** *$0.01 per month annually ($0.12 more per year)*	375 by 2025 (75 per year)	Address some of the polemount transformers identified as very poor in the Asset Condition Assessment report.
Included in Draft Plan *Within proposed average 2.4% increase over 5-years*	250 by 2025 (50 per year)	Address some of the polemount transformers identified as very poor in the Asset Condition Assessment report.
Slower Pace ***Decrease*** *of $0.01 per month annually ($0.12 less per year)*	125 by 2025 (25 per year)	Address only the worst of the polemount transformers identified as very poor in the Asset Condition Assessment report.
Additional Feedback (Optional)		

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Making Choices (3 of 7)

Converting Outdated Underground Kiosk Transformers

NPEI's system features a type of underground transformer that was popular in the 1940s to 1970s which no longer meets construction and safety standards. While this equipment still functions, it is becoming increasingly difficult to safely and effectively maintain. When this equipment does fail, it can result in lengthy outages due to the limited accessibility due to the original method of construction.

On average, since 2014, NPEI has converted approximately 9 kiosk transformers per year. Between 2018 and 2019, the pace of this program has been pushed off, and today, there remains 75 transformers in need of replacement.

NPEI is proposing to convert all of this equipment within the next seven years, with 55 being converted in the next five year period. That said, there is an opportunity to convert these kiosk transformers more slowly.

Q11. Which of the following options do you prefer?

Option	Transformers Installed	Expected Outcome
Included in Draft Plan *Within proposed average 2.4% increase over 5-years*	55 by 2025 (11 per year)	Work towards eliminating all old installations over the next 7 years.
Reduced Pace ***Decrease*** *of $0.02 per month annually ($0.24 less per year)*	25 by 2025 (5 per year)	Work towards eliminating all old installations over the next 15 years.
Slower Pace ***Decrease*** *of $0.04 per month annually ($0.48 less per year)*	10 by 2025 (2 per year)	Work towards eliminating all old installations over the next 35 years.
Additional Feedback (Optional)		

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Making Choices (4 of 7)

Underground cable replacement

Many neighbourhoods across NPEI's service territory are serviced by underground cables. Historically, NPEI has taken a "run-to-failure" approach with this equipment; that is, a cable will be replaced only once it has failed. The age of this equipment is now becoming a concern, with approximately 78 km or 18% of underground cable operating beyond its estimated useful life of 35 years.

Since 2014, underground cable failure has directly resulted in approximately ten outages per year, and when these outages do occur, it can take NPEI crews an extended period to replace the cable and restore power to affected households and businesses.

Between 2021 and 2025, NPEI is proposing a new program that will replace cable that has been identified as past end of life when completing other associated work. NPEI believes that this could help reduce the number and length of outages caused by underground cable failure, as well as to start getting ahead of the ongoing age issue. That said, there is an opportunity to take a more proactive approach to addressing some of the older cable in the system.

Q12. Which of the following options do you prefer?

Option	Km of cable installed	Expected Outcome
Further Accelerated Pace ***Additional*** *$0.35 per month annually ($4.20 more per year)*	24 km by 2025 (4.8 km per year)	Proactively replace more of the cables identified as past end of life in the Asset Condition Assessment Report.
Accelerated Pace ***Additional*** *$0.07 per month annually ($0.84 more per year)*	12 km by 2025 (2.4 km per year)	Proactively replace some of the cables identified as past end of life in the Asset Condition Assessment Report.
Included in Draft Plan *Within proposed average 2.4% increase over 5-years*	2 km by 2025 (0.4 km per year)	Replace cables past end of life as other work is being completed on associated switchgear or riser poles.
Additional Feedback (Optional)		

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Planning for the Future: 2021-2025 Rate Application

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Making Choices (5 of 7)

Subdivision underground rehabilitation

71 of the subdivisions in NPEI's service territory were constructed with **direct buried cable** which refers to a type of construction where cables are laid directly in underground trenches without a protective barrier.

While this was typical construction at the time, 40 of these subdivisions were built 40 or more years ago, and the cables are now approaching the end of their recommended life.

In this upcoming plan, NPEI is proposing a new program to start preparing to upgrade the service in the subdivisions with the most pressing needs.

In order to keep costs down, NPEI is proposing to start rehabilitation of the underground "system" by installing ducts that will eventually carry underground cables over the next five years. The cables would be installed as needed (upon failure) or once all of the old subdivisions have had the duct installed.

Completing this work in two phases will not only save costs now, but also help ensure that NPEI will be able to rehabilitate the most subdivisions in the shortest time.

Between 2021 and 2025, NPEI is proposing a new program that will proactively install ducts in approximately 10 subdivisions. Which subdivisions receive investment first will predominantly be based on age. That said, there is an opportunity to either accelerate or slow down the pace of this new program.

Q13. Which of the following options do you prefer?

Option	Km of vault installed	Expected Outcome
Accelerated Pace ***<u>Additional</u>*** *$0.03 per month annually ($0.36 more per year)*	30 km by 2025 (6 km per year)	Install 6 km of ducts or approximately four subdivisions per year.
Included in Draft Plan *Within proposed average 2.4% increase over 5-years*	15 km by 2025 (3 km per year)	Install 3 km of ducts or approximately two subdivisions per year.
Slower Pace ***<u>Decrease</u>*** *of $0.01 per month annually ($0.12 less per year)*	7.5 km by 2025 (1.5 km per year)	Install 1.5 km of ducts or approximately one subdivision per year.
Additional Feedback (Optional)		

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Making Choices (6 of 7)

Overhead rebuilds

Beyond replacing overhead poles, NPEI has a program that rebuilds the overhead system for entire streets and neighbourhoods. This includes poles, wires, and all other equipment that goes into operating the overhead system.

A recent asset health condition assessment identified a total of **60 areas** within NPEI's service territory that require complete overhead rebuilds**.** Most of this equipment is either beyond its recommended age or deteriorated due to weather and other factors. This infrastructure is in addition to the poles identified in the earlier section.

This program is intended to contribute to the "betterment" of the overhead system by;

- Improving system performance by installing animal guards and higher capacity transformers to reduce the likelihood of outages, and;
- Improving system aesthetics with new and taller poles.

On average, each of the projects would replace approximately 30-40 poles, depending on the population density of the area being worked on. NPEI's current approach would rebuild **40 out of 60 areas** in the 2021 to 2025 period.

NPEI must continue to invest in overhead rebuilds, therefore, this is a matter of whether customers would rather pay more during the upcoming period or push some level of investment beyond the next five years.

Q14. Which of the following options do you prefer?

Option	Overhead rebuilds	Expected Outcome
Accelerated Pace ***Additional*** *$0.04 per month annually ($0.48 more per year)*	61 km by 2025 (12.2 km per year)	Rebuild 12.2 km per year or approximately 10 projects per year
Included in Draft Plan *Within proposed average 2.4% increase over 5-years*	48.5 km by 2025 (9.7 km per year)	Rebuild areas with assets that have been identified as very poor in Asset Condition Assessment. Rebuild 9.7 km per year or approximately 8 projects per year
Slower Pace ***Decrease*** *of $0.04 per month annually ($0.48 less per year)*	36 km by 2025 (7.2 km per year)	Rebuild 7.2 km per year or approximately 6 projects per year
Additional Feedback (Optional)		

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Making Choices (7 of 7)

Grid modernization

New technology has changed the way that NPEI can manage and monitor the distribution system.

Supervisory Control and Data Acquisition (SCADA) systems allow NPEI staff the ability to remotely monitor and trace system faults and re-close switches from a control room rather than sending a repair crew to patrol the lines. These systems are particularly effective where there are larger distances between customers, for instance, in more rural areas of the western region of NPEI's service territory.

This equipment can have significant positive impacts on restoration times when an outage does occur, particularly in instances such as during a severe weather event.

Q15. Which of the following options do you prefer?

Option	Devices installed	Expected Outcome
Accelerated Pace ***Additional*** *$0.01 per month annually ($0.12 more per year)*	20 devices (4 per year)	NPEI to double installation rate to four devices per year.
Included in Draft Plan *Within proposed average 2.4% increase over 5-years*	10 Devices (2 per year)	Remain at current installation pace of two devices per year. Install new devices to expand NPEI's Smart Grid network. These devices provide better monitoring capability on the system, which leads to improved restoration times during outages.
Slower Pace ***Decrease*** *of $0.01 per month annually ($0.12 less per year)*	5 Devices (1 per year)	NPEI to cut rate of installation in half to one device per year.

Additional Feedback (Optional)

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Impact of Choices

Investment Alternative Summary

Throughout this workbook, you have been asked about **seven key choices** that could impact your rates. Below is a summary of your answers to the questions that could impact your rates.

At the bottom of this page you will find the total bill impact of all the answers.

Having seen the total bill impact, please review your answers and change your responses if you desire; your potential rate impact will be re-calculated. You will have the opportunity to continue adjusting your answers until you feel you've reached the best balance for you.

Overhead pole replacement

- ☐ **Accelerated Pace**: Additional $0.03 per month annually ($0.36 more per year annually)
- ☐ **Included in Draft Plan**: Within proposed average 2.4% increase over 5-years
- ☐ **Slower Pace**: Decrease of $0.02 per month annually ($0.24 less per year)

Note: these areas will be uniquely populated for each individual customer. The bill impacts of their individual responses will be summed and displayed below.

The total impact of your choices would result in:

+/- $X.XX per month annually (+/- $X.XX per year)

This is in addition to the estimated 2.4% annual increase if Niagara Peninsula Energy continues with its current draft plan.

Impact of Choices

Assessing Niagara Peninsula Energy's draft 2021-2025 plan

Again, it is estimated that if NPEI continues with its preliminary plan, the distribution portion of the bill will increase by $4.84 per month in 2021, when the plan is set to come into effect. For the period 2022-2025, the annual bill increase is limited by the OEB to be less than the rate of inflation.

- At the end of the 5-year plan, the typical small business customer would see the distribution portion of their electricity bill increase by $8.46.
- As a result, the distribution charges on the typical small business customer's monthly bill would increase from $69.15 in 2020 to $77.61 by 2025.

Estimated Typical Small Business Annual Increase in Monthly Bill (5 year forecast)

	Year	Average Small Business Bill	Distribution Portion of Bill	Incremental Rate Change	% Change * (on distribution portion of bill)
Current Rate	2019	$298.63	$68.28		
Budgeted Rate	2020	$303.11	$69.15	$0.87	1.27%
Forecast for next rate period	2021	$306.98	$73.99	$4.84	7.00%
	2022	$311.58	$74.88	$0.89	1.20%
	2023	$316.26	$75.78	$0.90	1.20%
	2024	$321.00	$76.69	$0.91	1.20%
	2025	$325.82	$77.61	$0.92	1.20%
				$8.46	

*** These estimates are preliminary, and are subject to your feedback as the business plan is finalized .**

Q16. Considering what you know about Niagara Peninsula Energy's draft plan – which would see the typical small business customer's distribution portion of their bill increase by $8.46 over the 5-year period – which of the following best represents your point of view?

- ☐ NPEI should improve service, as discussed on the previous pages, even if that means an increase that exceeds $8.46 over the 5-year period
- ☐ 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.
- ☐ NPEI should keep increases below $8.46, even if that could mean reductions in service over the 5-year period.
- ☐ Other [Please specify]
- ☐ Don't know

Q17. Thinking about your answer to the previous question, why do you feel that NPEI should take that approach over the 2021-2025 period? (Optional) [OPEN]

Q18. Do you have any final comments regarding NPEI or the customer engagement that you just completed? (Optional) [OPEN]

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About you

More about your organization

The following questions are for statistical purposes only. This information is used to segment and group similar people together when the survey results are analysed.

Q19. To the best of your knowledge, does your organization receive electrical service via overhead wires, underground cables?

- Overhead wires
- Underground cables
- Don't know

Q19b. Have you experienced any power outages at your organization in the past 12 months which lasted longer than one minute?

- No outages
- 1 outage
- 2 outages
- 3 or more outages
- Don't know

To what extent do you agree or disagree with the following statements?

Q20. The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.

- Strongly agree
- Somewhat agree
- Somewhat disagree
- Strongly disagree
- Don't know/No opinion

Q21. Customers are well served by the electricity system in Ontario.

- Strongly agree
- Somewhat agree
- Somewhat disagree
- Strongly disagree
- Don't know/No opinion

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About you

More about your organization

Q22. As part of your job, are you in charge of managing or overseeing your organization's electricity or hydro bill?

- Yes
- No
- Don't know

Q23. Which of the following best describes the sector in which your business operates?

- Commercial
- Manufacturing/Industrial
- Data Centre
- Hospitality
- Restaurant/Tavern
- Retail
- Warehouse
- Other (Please specify)
- Prefer not to say

Q24. Including yourself, how many people work at your organization?

- 1 person
- 2 to 5 people
- 6 to 10 people
- 11 to 25 people
- 26 to 50 people
- More than 50 people
- Prefer not to say

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Final Thoughts

Feedback on Niagara Peninsula Energy's Consultation

Niagara Peninsula Energy values your feedback. This is the first time the utility has conducted a review about its upcoming plans in this type of format.

Q25. Overall, did you have a favourable or unfavourable impression of the consultation you just completed?

- Very favourable
- Somewhat favourable
- Somewhat unfavourable
- Very unfavourable
- Don't know

Q26. In this consultation, do you feel that NPEI provided too much information, not enough, or just the right amount?

- Too little information
- Just the right amount of information
- Too much information

Q27. Was there any content missing that you would have liked to have seen included in this consultation?

- None

Q28. Is there anything that you would still like answered?

- None

Appendix 1-27

Large Commercial Customer Engagement Workbook

Customer Engagement Workbook

GS>50kW Workbook

November 2019

STRICTLY PRIVILEGED AND CONFIDENTIAL

About this Consultation

Welcome to Niagara Peninsula Energy's Customer Engagement!

Niagara Peninsula Energy (NPEI) needs your input on choices that will impact the services you receive and the rates that you pay.

- **NPEI** is developing its investment plan for 2021 to 2025. This plan will determine the investments NPEI will make in equipment and infrastructure; the services it provides; and the rates you pay.
- As **NPEI** plans for the future, they want to ensure their business decisions are aligned with customers priorities, preferences, and needs.
- Throughout this survey, information will be provided in an effort to give you more background on which to base your responses.
- While responding to the following questions, remember that there are no wrong answers, and that your individual responses will remain anonymous.
- This customer engagement will take approximately 25-35 minutes to complete, depending on the level of feedback you wish to provide. Your progress will be saved as you move through the workbook, meaning you can leave and return to the customer engagement at any time.

All individual responses will be kept confidential. Innovative Research Group (INNOVATIVE), an independent research company, has been hired NPEI to gather your feedback.

Those who complete the questions that follow will be invited to enter a draw to win one (1) $500 cash prize.

If you are reading this on a smaller mobile device, you may want to consider accessing the survey from a tablet, desktop or laptop instead so that it is easier for you to read.

Please note that the estimates throughout are for illustrative purposes only and may not reflect the actual size of your organization's monthly electricity bill.

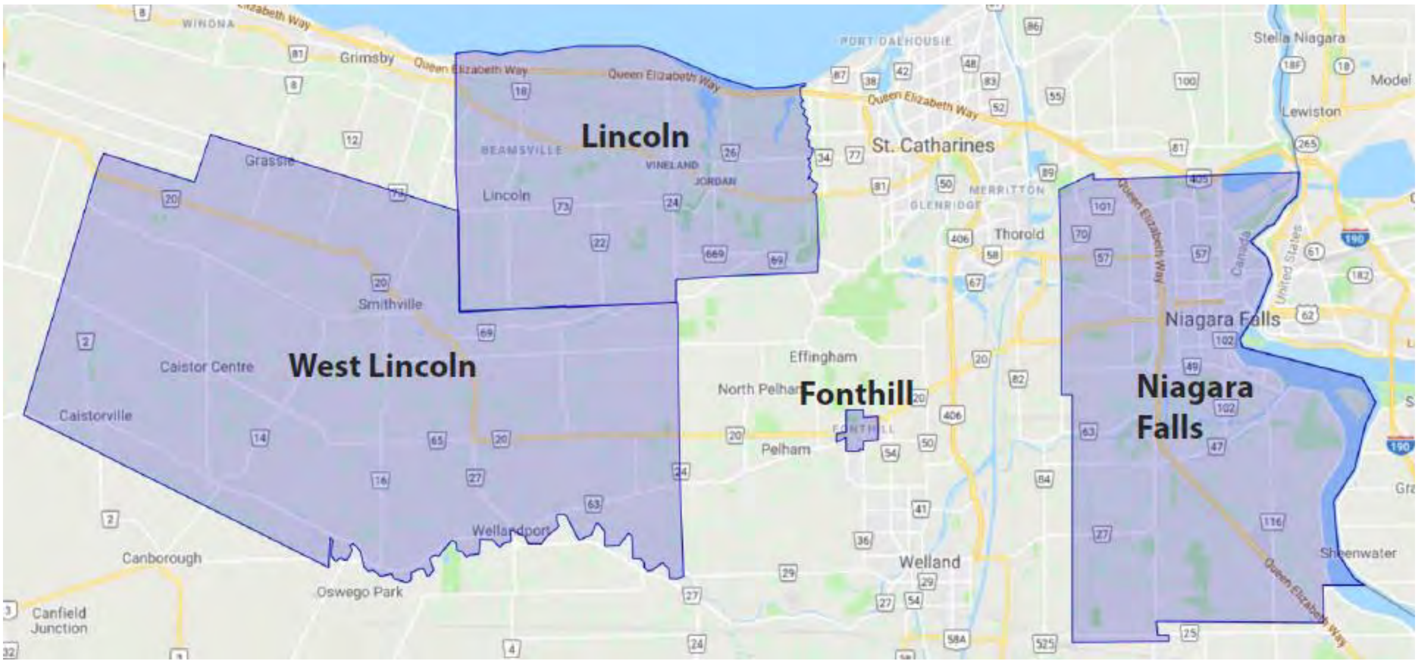
For the purpose of this exercise, the estimates are based on a customer with a monthly demand of 180 kW and monthly consumption of 65,000 kWh.

Electricity 101

Who is Niagara Peninsula Energy?

NPEI provides local electricity distribution and related services to residential and business customers in the City of Niagara Falls, Town of Lincoln, Town of Pelham, and Township of West Lincoln.

- NPEI serves an area of approximately 827 square kilometers and 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 local distribution company (LDC) and regulated entity, NPEI applies for, and receives approval from the regulator to charge for its services.



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Electricity 101

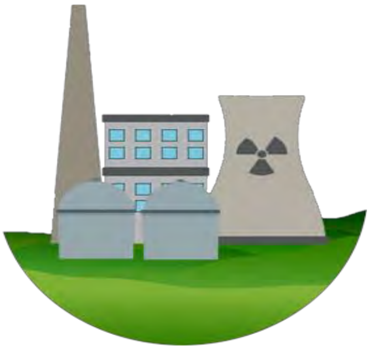
Niagara Peninsula Energy's Role in Ontario's Electricity System

Ontario's electricity system is owned and operated by public, private, and municipal corporations across the province. It is made up of three key components: **generation**, **transmission** and **distribution**.

Generation

Where electricity comes from

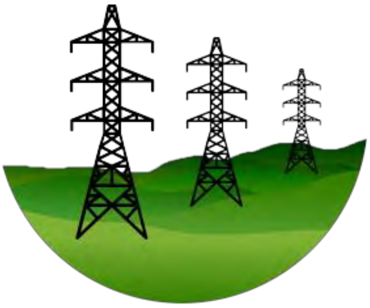
Ontario's electricity is generated using a mix of nuclear, gas-fired, and water power (hydro), as well as biomass and renewable sources such as wind and solar technology. In Ontario, a number of companies own these generating stations but approximately half of the electricity is generated by Ontario 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.



Transmission

How electricity travels across Ontario

Once generated, electricity must be transported to electrical substations 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 kilometres of 'electricity highway', most of which is owned and operated by Hydro One.



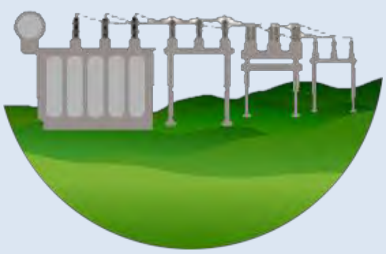
Local Distribution

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. This local distribution system includes transformer stations that decrease the voltage of the electricity so it can be used safely in your home or business.

There are approximately 1,451 km of overhead power lines and 573 km of underground cable. Through this distribution network, NPEI delivers electricity to approximately 55,600 residential and business customers.

Niagara Peninsula Energy Inc. is jointly owned by the **City of Niagara Falls**, the **Town of Lincoln**, the **Town of Pelham** and the **Township of West Lincoln**.



npe niagara peninsula energy Inc.
Your Local Utility

Q1. Before this survey, how familiar were you with Niagara Peninsula Energy, which operates the electricity distribution system in your community?

- ☐ Very familiar
- ☐ Somewhat familiar
- ☐ Not familiar at all
- ☐ Don't know

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Electricity 101

How much of my electricity bill goes to Niagara Peninsula Energy?

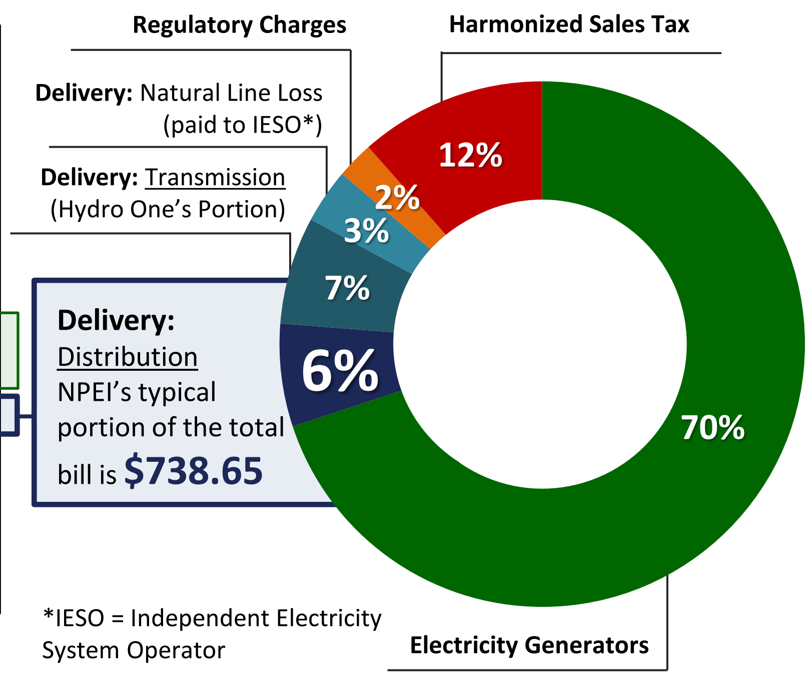
- Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board (OEB), the provincial energy regulator.
- While NPEI is responsible for collecting payment for the entire electricity bill, it retains only the distribution portion of the delivery charge.
- Distribution makes up about **16%** of the typical mid-sized business customer's bill.
- The rest of your bill is passed onto provincial transmission companies, power generation companies, the government and regulatory agencies.

NPEI Sample Monthly Bill*
(Based on 180 kW Monthly Demand)

Account Number:
000 000 000 000 0000

Meter Number:
00000000

Your Electricity Charges	
Electricity	
Electricity Charge	1,202.50
Global Adjustment	6,951.10
Delivery	1,900.21
Regulatory Charges	265.89
Total Electricity Charges	**$10,319.71**
HST	1,341.56
Total Amount	**$11,661.27**



*IESO = Independent Electricity System Operator

* As of November 1, 2019. Based on typical monthly consumption of 65,000 kWh

Q2. Thinking specifically about the services provided to you and your community by Niagara Peninsula Energy, overall, how satisfied or dissatisfied are you with the services that your organization receive?

- ☐ Very satisfied
- ☐ Somewhat satisfied
- ☐ Neither satisfied nor dissatisfied
- ☐ Somewhat dissatisfied
- ☐ Very dissatisfied
- ☐ Don't know

Q3. Before this survey, how familiar were you with the amount of your organization's electricity bill that went to Niagara Peninsula Energy?

- ☐ Very familiar
- ☐ Somewhat familiar
- ☐ Not familiar
- ☐ Don't know

Q4. Is there anything in particular you would like Niagara Peninsula Energy to do to improve its services to your organization?

Niagara Peninsula Energy Background

Building Niagara Peninsula Energy's draft plan

NPEI has put together its draft business plan based on the information and input from various sources, such as:

- **Legal and regulatory** requirements by continuing to meet its obligations.
- **Internal business planning** based on expert analysis and professional judgment to develop construction and operations programs that address safety, business, technical, and operational needs.
- **Customer feedback** collected through both ongoing dialogues and specific engagements, such as this.

There are three key organizations responsible for setting the policy direction of Ontario's electricity system. The decisions made by these organizations impact how utilities operate their businesses and serve their customers.

- **Policy**: The Ontario Ministry of Energy, Northern Development and Mines (MNDM) creates energy policy for the province.
- **Regulation**: The electricity industry in Ontario is regulated by the Ontario Energy Board (OEB). One of the OEB's roles is to review the business and distribution plans of all electricity distributors and approve the rates that they charge customers.
- **Operations and Planning**: The Independent Electricity System Operator (IESO) manages the provincial electricity grid, plans for the province's future energy needs, and develops conservation programs.

Ontario ENERGY /ÉNERGIE

ONTARIO ENERGY BOARD

ieso Connecting Today. Powering Tomorrow.

Niagara Peninsula Energy Background

How did customer feedback shape Niagara Peninsula Energy's draft plan?

NPEI is placing more emphasis on incorporating customer feedback into the planning process than ever before.

NPEI engages with its customers both in day-to-day interactions and in a variety of customer engagement activities. These interactions help identify customer needs and preferences, and inform how the utility plans for the future.

This past summer, NPEI engaged with **thousands of residential and business customers** from across its service territory – both in person and through telephone and online surveys.

What did NPEI hear from customers like yourself?

1. The clear majority of NPEI residential and small business customers are satisfied with the current service they receive. When asked how NPEI can improve service, top responses for residential customers were "nothing", followed by "lower or reduce rates".
2. Among competing outcomes, **price**, **reliability**, and **finding internal cost efficiencies** are the top three priorities for both residential and small business customers.
3. While keeping price at a reasonable and affordable level is an important priority, many customers feel that investing in the grid to maintain reliability, is preferable to deferring investments to keep bills low.

Considering this feedback, as well as the information and inputs discussed on the previous page, NPEI has developed a draft plan that is responsive to:

1. Legal requirements by continuing to meet its obligations, including safety and reliability;
2. A transformer station upgrade to accommodate the new Niagara South Hospital and future surrounding growth.
3. Mandatory service connections to accommodate new customers and customer-required upgrades, of which NPEI does not have control over how and when these costs are incurred.
4. Customer feedback by:
    a) Keeping distribution price increases as low as possible;
    b) Maintaining long-term performance for customers experiencing average or better service;
    c) Improving service levels for customers experiencing below average service or who have special reliability needs (e.g. hospitals); and,
    d) Balancing other customer priorities (e.g. customer service) with the need to contain rate increases.

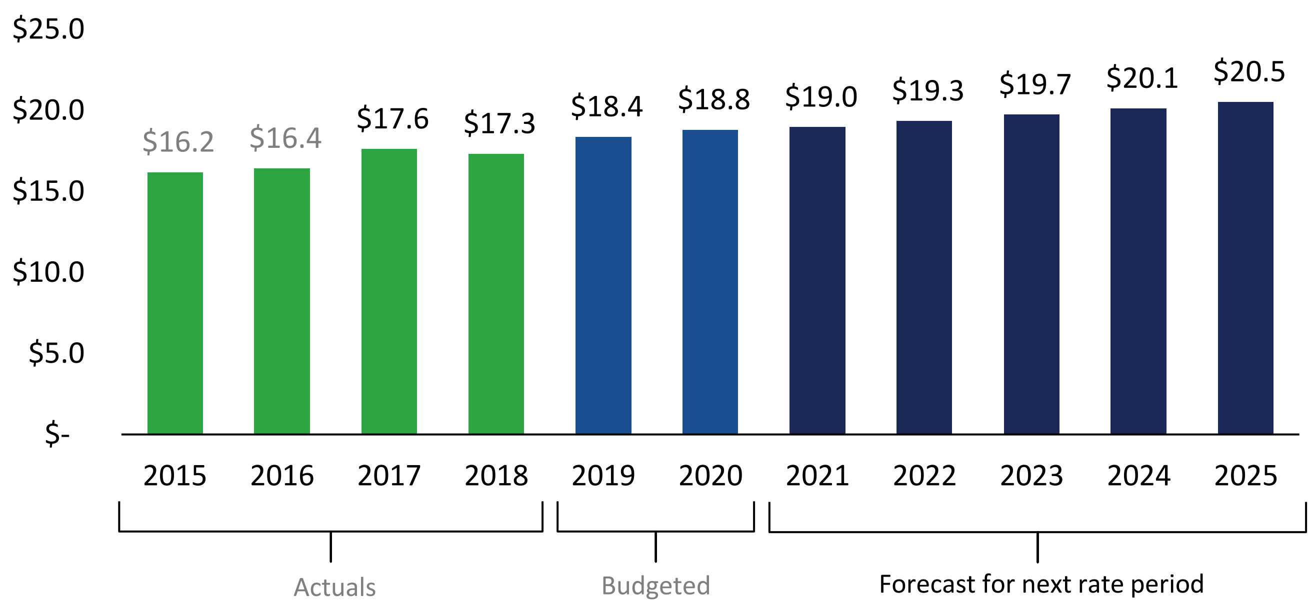
Niagara Peninsula Energy Background

Operating Expenses

In this section, we want to focus on operating expenses and how NPEI compares to its peers.

NPEI's operating budget covers recurring expenses, such as the maintenance of poles, wires, transformers, fleet and buildings as well as proactive maintenance programs such as tree trimming, and payroll for employees. Meter reading, postage, cyber security and hardware/software maintenance expenses are billing and customer service-related expenses. The proposed 5-year plan, between 2021 and 2025, would see NPEI spend an estimated total of $98.7 million on operations.

NPEI's Current and Forecasted Operating Expenses, per Year (Millions)*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

NPEI's **operating costs** are benchmarked by the OEB against other utilities in Ontario. In the last year of publicly available data collected by the OEB, NPEI's operating costs per customer was **$311.67**, which is slightly more than some, while less than both Hydro One and Canadian Niagara Power.

2018 Operating & Maintenance and Administration (OM&A) Per Customer ($)

The diverse geographical nature of NPEI's service territory, which is a mix of urban and rural communities is a large consideration/driver of these OM&A costs. In some parts of the service territory, there may be less than 30 customers per kilometer of line. Despite low density, these lines still require the same level of ongoing maintenance, including tree trimming and other expenses that contribute to operating the system; thereby resulting in a higher cost per customer.

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Niagara Peninsula Energy Background

Operating Expenses

Recall, this customer feedback portal does not ask questions that expect you to be an electricity expert.

The OEB runs an open and transparent review process where experts from the OEB and intervenor groups review and challenge NPEI's analyses and assessments. You are welcome to participate in the OEB process if you are interested in those issues. Details can be found at oeb.ca/participate.

This customer engagement however, is focused on capital investments.

Detailed discussion of NPEI's operating budget is left to experts from the OEB and intervenors in the formal rate application review; this workbook focuses on collecting your view on competing trade-offs in capital investments.

Q5. Does leaving the detailed discussion about Niagara Peninsula Energy's operating budget to experts from the OEB and intervenors seem like the right approach or wrong approach to you?

- ◻ Definitely the right approach
- ◻ Probably the right approach
- ◻ Probably the wrong approach
- ◻ Definitely the wrong approach
- ◻ Don't know enough to say

Additional Feedback (Optional)

Q6. [If wrong approach] And why do you say leaving the detailed discussion about NPEI's operating budget to the OEB and intervenors is the wrong approach? [OPEN]

Niagara Peninsula Energy Background

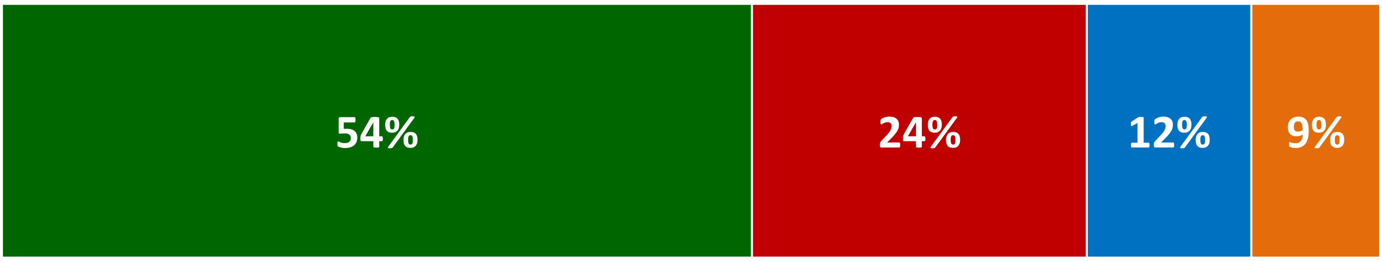
Capital Investments

NPEI's **capital budget** covers items that, once purchased, have lasting benefits over many years. Year-over-year, regardless of external drivers, NPEI will need to make investments in the core distribution system, including poles, wires, cables and transformers.

Based on initial customer input and the approach outlined previously, NPEI believes the capital expenditure required to address system renewal, maintain system reliability and safety, and invest in other infrastructure priorities between 2021 and 2025 is estimated to be **$70.3 million**.

NPEI classifies the costs of four types of capital investment between 2021 and 2025. Each of these four investment categories helps NPEI pace and prioritize projects.

2021-2025 Forecasted Capital Investments



System Renewal ($38.2 million)

These projects are a mix of planned end-of-life replacements and emergency replacements.

Projects Include: Replacement of existing overhead wires, poles, and pole mounted transformers, underground cables and transformers and transformer station upgrades.

System Access ($17.1 million)

"Must do" investments that respond to customer requests for new connections or new infrastructure development.

Projects Include: NPEI's share of new subdivisions, new upgraded commercial and industrial services, and relocating assets based on road infrastructure needs.

General Plant ($8.4 million)

These are investments needed to support the distribution system, such as tools, vehicles, buildings, and computers.

Projects Include: Financial and customer IT systems, enhanced cyber security investments, facility renovations, backup generation, and vehicle replacements.

System Service ($6.6 million)

These investments consist of projects that address capacity constraints, improve system reliability and customer service.

Projects Include: Installation of automated switches and system expansion to supply new development.

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Niagara Peninsula Energy Background

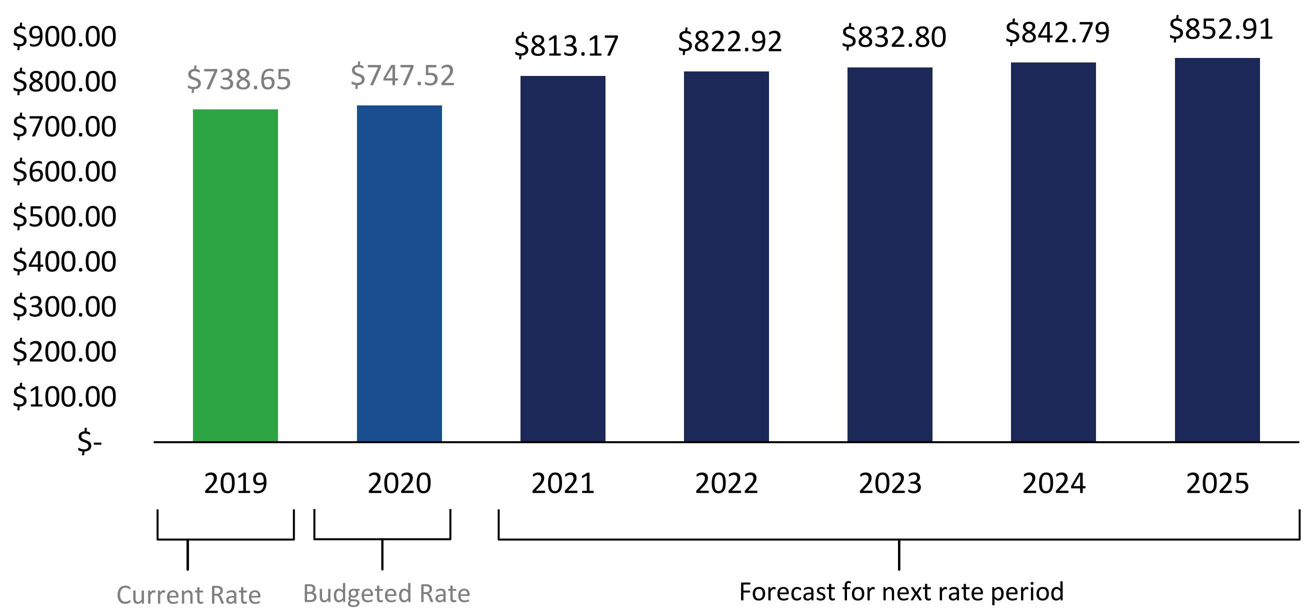
How much will this draft plan cost my organization?

Remember, the current typical NPEI mid-sized business customer's electricity bill is about $11,600 per month, of which $738.65 goes to NPEI.

It is estimated that if NPEI continues with its preliminary plan, the distribution portion of the bill will increase by $65.65 per month in 2021, when the plan is set to come into effect. For the period 2022-2025, the annual bill increase is limited by the OEB to be less than the rate of inflation.

- At the end of the 5-year plan, the typical mid-sized business customer would see the distribution portion of their electricity bill increase by $105.39.
- As a result, the distribution charges on the typical mid-sized business customer's monthly bill would increase from $747.52 in 2020 to $852.91 by 2025.

Estimated Mid-Sized Business Monthly Distribution Charge, per Year*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

NPEI is looking for your input on its preliminary plan to ensure it is making the spending decisions that matter to you, the customer.

The following sections of this workbook will explore some of the choices Niagara Peninsula Energy needs to make to help finalize its preliminary plan.

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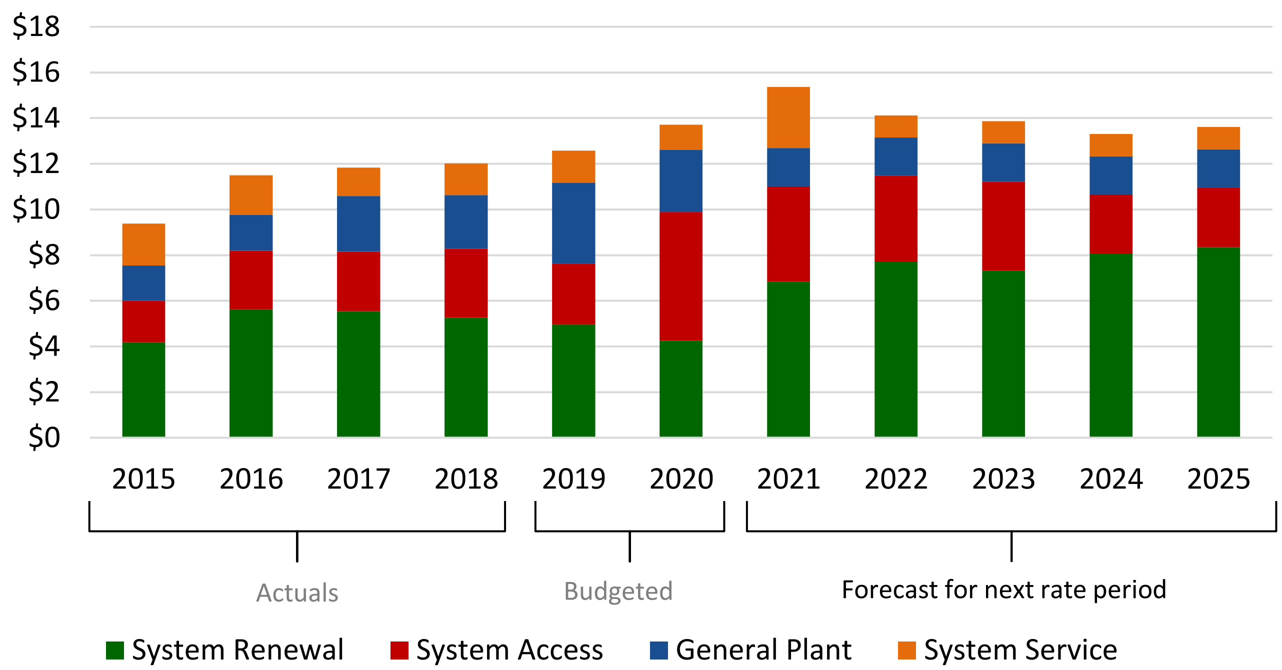
Niagara Peninsula Energy Background

Pacing Capital Investments

The overall amount NPEI invests in capital projects remains generally the same year over year, but what does change is where these investments are made. In some years, when unplanned or unforeseen investments are needed, NPEI will re-allocate funds to make room for these projects within the approved budget. This helps limit the overall amount that the distribution charges fluctuate year-over-year.

The chart below outlines NPEI's spending in past years, and proposed spending for the 5-year period 2021 to 2025.

2015 – 2025 Historical and Forecasted Capital Investments*



* **These estimates are preliminary, and are subject to your feedback as the business plan is finalized.**

System Access expenditures are budgeted to increase to $5.6M in 2020 to accommodate a number of large commercial customer growth projects as well as municipal road work.

Q7. Which of the following statements best represents your point of view regarding Niagara Peninsula Energy's approach to pacing investments?

- ☐ Niagara Peninsula Energy should keep spending levels consistent year-over-year, even if that means deferring investments to other years to lessen the impact of any bill increase.
- ☐ Niagara Peninsula Energy should not defer investments, even if that means larger bill increases in some years.
- ☐ Don't know

Additional Feedback (Optional)

Niagara Peninsula Energy Background

Mandatory Investments

Federal, provincial, and municipal governments as well as regulators set requirements and standards that NPEI must satisfy. Mandatory investments can be broken down into three categories:

- **Connecting customers**: This includes connecting customers to the grid when a new home or building is constructed or modified.
- **Moving equipment**: This includes moving equipment like poles and cables for road widening.
- **Mandated obligations**: This includes installing and maintaining customer meters and transferring electricity from the provincial transmission system.

These mandatory investments mean that about **one-in-four dollars (23%)** of your distribution rates over the past five years have not been available for other non-mandatory investments. Looking forward to the 2021-2025 period, NPEI forecasts a similar level of mandatory investments, driven largely by:

- **Preparing to connect the new Niagara South hospital;**
- **Work to accommodate the 2021 Canada Summer Games in the Niagara Region, and;**
- **Work to accommodate growth and future electricity capacity needs.**

Q8. Which of the following statements best represents your point of view regarding Niagara Peninsula Energy's approach to mandatory and non-mandatory spending?

- ☐ When Niagara Peninsula Energy encounters unforeseen increases in mandatory requirements, planned non-mandatory expenditures should be deferred to keep rate impacts down, even if that could result in a potential decline in service in the near future.
- ☐ When Niagara Peninsula Energy encounters unforeseen increases in mandatory requirements, it should not defer planned non-mandatory expenditures, even if that could result in cost increases to customers over the next five years.
- ☐ Don't know

Additional Feedback (Optional)

Making Choices (1 of 7)

Overhead Pole Replacement

A recent asset health condition assessment shows that **575 or approximately 3%** of the poles in NPEI's distribution system are in *poor* or *very poor* condition. Each year, new poles enter this condition, and NPEI takes an approach that proactively replaces poles as to not create a large backlog. As a general rule, pole failure only causes an outage when something happens outside of the utility's control, most frequently due to trees knocking them down or a car accident.

On average, since 2014, NPEI has replaced approximately 88 poles per year. This pace has effectively maintained reliability over this period.

NPEI is proposing to replace most of these 575 poles in poor and very poor condition over the course of the next five years, however, there is an opportunity to replace these poles more quickly or slowly. NPEI must continue to invest in overhead pole replacement, therefore, this is a matter of whether customers would rather pay more during the upcoming period, or push some level of investment beyond the next five years.

Q9. Which of the following options do you prefer?

Option	Poles Replaced	Expected Outcome
Accelerated Pace ***Additional*** *$0.52 per month annually ($6.24 more per year)*	1,000 by 2025 (200 per year)	Address the very poor and some of the poor condition poles identified in the Asset Condition Assessment.
Included in Draft Plan *Within proposed average 2.7% increase over 5-years*	500 by 2025 (100 per year)	Address most of the very poor condition poles identified in the Asset Condition Assessment and annual pole inspections by 2025.
Slower Pace ***Decrease*** *of $0.25 per month annually ($3.00 less per year)*	250 by 2025 (50 per year)	Address only the poles in need of immediate replacement, as identified in the annual pole inspection report.

Additional Feedback (Optional)

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Making Choices (2 of 7)

Overhead transformer replacement

Transformers are a critical piece of distribution equipment that reduce voltage from the higher levels that are more efficient to move electricity long distances to lower levels that are safer to connect to homes and businesses. They are typically either located on the ground, in underground vaults, or attached to distribution poles

A recent asset health condition assessment shows that **1,251 or approximately 21%** of the overhead transformers in NPEI's distribution system are in poor or very poor condition.

Since 2014, overhead transformer failure has directly resulted in approximately 15 outages per year. That said, in most cases, when an overhead transformer fails, it only impacts a small amount of customers and the equipment can be replaced within 2-3 hours depending on the circumstances.

However, when these outages do occur, it can take NPEI crews an extended period of time to replace the cable and restore power to affected households and businesses.

NPEI is proposing a new program to proactively replace **250 of the 677 or 37%** of the overhead transformers identified as very poor condition before they fail over the course of the next five years.

As with distribution poles, NPEI will proactively invest in overhead transformer replacement, therefore, this is a matter of whether customers would rather pay more during the upcoming period, or push some level of investment beyond the next five years.

Q10. Which of the following options do you prefer?

Option	Transformers Replaced	Expected Outcome
Accelerated Pace ***Additional*** *$0.18 per month annually ($2.16 more per year)*	375 by 2025 (75 per year)	Address some of the polemount transformers identified as very poor in the Asset Condition Assessment report.
Included in Draft Plan *Within proposed average 2.7% increase over 5-years*	250 by 2025 (50 per year)	Address some of the polemount transformers identified as very poor in the Asset Condition Assessment report.
Slower Pace ***Decrease*** *of $0.16 per month annually ($1.92 less per year)*	125 by 2025 (25 per year)	Address only the worst of the polemount transformers identified as very poor in the Asset Condition Assessment report.
Additional Feedback (Optional)		

Making Choices (3 of 7)

Converting Outdated Underground Kiosk Transformers

NPEI's system features a type of underground transformer that was popular in the 1940s to 1970s which no longer meets construction and safety standards. While this equipment still functions, it is becoming increasingly difficult to safely and effectively maintain. When this equipment does fail, it can result in lengthy outages due to the limited accessibility due to the original method of construction.

On average, since 2014, NPEI has converted approximately 9 kiosk transformers per year. Between 2018 and 2019, the pace of this program has been pushed off, and today, there remains 75 transformers in need of replacement.

NPEI is proposing to convert all of this equipment within the next seven years, with 55 being converted in the next five year period. That said, there is an opportunity to convert these kiosk transformers more slowly.

Q11. Which of the following options do you prefer?

Option	Transformers Installed	Expected Outcome
Included in Draft Plan *Within proposed average 2.7% increase over 5-years*	55 by 2025 (11 per year)	Work towards eliminating all old installations over the next 7 years.
Reduced Pace ***Decrease** of $0.40 per month annually ($4.80 less per year)*	25 by 2025 (5 per year)	Work towards eliminating all old installations over the next 15 years.
Slower Pace ***Decrease** of $0.61 per month annually ($7.32 less per year)*	10 by 2025 (2 per year)	Work towards eliminating all old installations over the next 35 years.

Additional Feedback (Optional)

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Making Choices (4 of 7)

Underground cable replacement

Many neighbourhoods across NPEI's service territory are serviced by underground cables. Historically, NPEI has taken a "run-to-failure" approach with this equipment; that is, a cable will be replaced only once it has failed. The age of this equipment is now becoming a concern, with approximately 78 km or 18% of underground cable operating beyond its estimated useful life of 35 years.

Since 2014, underground cable failure has directly resulted in approximately ten outages per year, and when these outages do occur, it can take NPEI crews an extended period to replace the cable and restore power to affected households and businesses.

Between 2021 and 2025, NPEI is proposing a new program that will replace cable that has been identified as past end of life when completing other associated work. NPEI believes that this could help reduce the number and length of outages caused by underground cable failure, as well as to start getting ahead of the ongoing age issue. That said, there is an opportunity to take a more proactive approach to addressing some of the older cable in the system.

Q12. Which of the following options do you prefer?

Option	Km of cable installed	Expected Outcome
Further Accelerated Pace ***Additional*** *$2.64 per month annually ($31.68 more per year)*	24 km by 2025 (4.8 km per year)	Proactively replace more of the cables identified as past end of life in the Asset Condition Assessment Report.
Accelerated Pace ***Additional*** *$1.21 per month annually ($14.52 more per year)*	12 km by 2025 (2.4 km per year)	Proactively replace some of the cables identified as past end of life in the Asset Condition Assessment Report.
Included in Draft Plan *Within proposed average 2.7% increase over 5-years*	2 km by 2025 (0.4 km per year)	Replace cables past end of life as other work is being completed on associated switchgear or riser poles.

Additional Feedback (Optional)

Making Choices (5 of 7)

Subdivision underground rehabilitation

71 of the subdivisions in NPEI's service territory were constructed with **direct buried cable** which refers to a type of construction where cables are laid directly in underground trenches without a protective barrier.

While this was typical construction at the time, 40 of these subdivisions were built 40 or more years ago, and the cables are now approaching the end of their recommended life.

In this upcoming plan, NPEI is proposing a new program to start preparing to upgrade the service in the subdivisions with the most pressing needs.

In order to keep costs down, NPEI is proposing to start rehabilitation of the underground "system" by installing ducts that will eventually carry underground cables over the next five years. The cables would be installed as needed (upon failure) or once all of the old subdivisions have had the duct installed.

Completing this work in two phases will not only save costs now, but also help ensure that NPEI will be able to rehabilitate the most subdivisions in the shortest time.

Between 2021 and 2025, NPEI is proposing a new program that will proactively install ducts in approximately 10 subdivisions. Which subdivisions receive investment first will predominantly be based on age. That said, there is an opportunity to either accelerate or slow down the pace of this new program.

Q13. Which of the following options do you prefer?

Option	Km of vault installed	Expected Outcome
Accelerated Pace ***Additional*** *$0.48 per month annually ($5.76 more per year)*	30 km by 2025 (6 km per year)	Install 6 km of ducts or approximately four subdivisions per year.
Included in Draft Plan *Within proposed average 2.7% increase over 5-years*	15 km by 2025 (3 km per year)	Install 3 km of ducts or approximately two subdivisions per year.
Slower Pace ***Decrease*** *of $0.23 per month annually ($2.76 less per year)*	7.5 km by 2025 (1.5 km per year)	Install 1.5 km of ducts or approximately one subdivision per year.

Additional Feedback (Optional)

Making Choices (6 of 7)

Overhead rebuilds

Beyond replacing overhead poles, NPEI has a program that rebuilds the overhead system for entire streets and neighbourhoods. This includes poles, wires, and all other equipment that goes into operating the overhead system.

A recent asset health condition assessment identified a total of **60 areas** within NPEI's service territory that require complete overhead rebuilds**.** Most of this equipment is either beyond its recommended age or deteriorated due to weather and other factors. This infrastructure is in addition to the poles identified in the earlier section.

This program is intended to contribute to the "betterment" of the overhead system by;

- Improving system performance by installing animal guards and higher capacity transformers to reduce the likelihood of outages, and;

- Improving system aesthetics with new and taller poles.

On average, each of the projects would replace approximately 30-40 poles, depending on the population density of the area being worked on. NPEI's current approach would rebuild **40 out of 60 areas** in the 2021 to 2025 period.

NPEI must continue to invest in overhead rebuilds, therefore, this is a matter of whether customers would rather pay more during the upcoming period or push some level of investment beyond the next five years.

Q14. Which of the following options do you prefer?

Option	Overhead rebuilds	Expected Outcome
Accelerated Pace ***<u>Additional</u>*** *$0.71 per month annually ($8.52 more per year)*	61 km by 2025 (12.2 km per year)	Rebuild 12.2 km per year or approximately 10 projects per year
Included in Draft Plan *Within proposed average 2.7% increase over 5-years*	48.5 km by 2025 (9.7 km per year)	Rebuild areas with assets that have been identified as very poor in Asset Condition Assessment. Rebuild 9.7 km per year or approximately 8 projects per year
Slower Pace ***<u>Decrease</u>*** *of $0.70 per month annually ($8.40 less per year)*	36 km by 2025 (7.2 km per year)	Rebuild 7.2 km per year or approximately 6 projects per year
Additional Feedback (Optional)		

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Making Choices (7 of 7)

Grid modernization

New technology has changed the way that NPEI can manage and monitor the distribution system.

Supervisory Control and Data Acquisition (SCADA) systems allow NPEI staff the ability to remotely monitor and trace system faults and re-close switches from a control room rather than sending a repair crew to patrol the lines. These systems are particularly effective where there are larger distances between customers, for instance, in more rural areas of the western region of NPEI's service territory.

This equipment can have significant positive impacts on restoration times when an outage does occur, particularly in instances such as during a severe weather event.

Q15. Which of the following options do you prefer?

Option	Devices installed	Expected Outcome
Accelerated Pace ***Additional*** *$0.14 per month annually ($1.68 more per year)*	20 devices (4 per year)	NPEI to double installation rate to four devices per year.
Included in Draft Plan *Within proposed average 2.7% increase over 5-years*	10 Devices (2 per year)	Remain at current installation pace of two devices per year. Install new devices to expand NPEI's Smart Grid network. These devices provide better monitoring capability on the system, which leads to improved restoration times during outages.
Slower Pace ***Decrease*** *of $0.06 per month annually ($0.72 less per year)*	5 Devices (1 per year)	NPEI to cut rate of installation in half to one device per year.
Additional Feedback (Optional)		

Impact of Choices

Investment Alternative Summary

Throughout this workbook, you have been asked about **seven key choices** that could impact your rates. Below is a summary of your answers to the questions that could impact your rates.

At the bottom of this page you will find the total bill impact of all the answers.

Having seen the total bill impact, please review your answers and change your responses if you desire; your potential rate impact will be re-calculated. You will have the opportunity to continue adjusting your answers until you feel you've reached the best balance for you.

Overhead pole replacement

- ☐ **Accelerated Pace**: Additional $0.52 per month annually ($6.24 more per year annually)
- ☐ **Included in Draft Plan**: Within proposed average 2.7% increase over 5-years
- ☐ **Slower Pace**: Decrease of $0.25 per month annually ($3.00 less per year)

Note: these areas will be uniquely populated for each individual customer. The bill impacts of their individual responses will be summed and displayed below.

The total impact of your choices would result in:

+/- $X.XX per month annually (+/- $X.XX per year)

This is in addition to the estimated 2.7% annual increase if Niagara Peninsula Energy continues with its current draft plan.

Impact of Choices

Assessing Niagara Peninsula Energy's draft 2021-2025 plan

Again, it is estimated that if NPEI continues with its preliminary plan, the distribution portion of the bill will increase by $65.65 per month in 2021, when the plan is set to come into effect. For the period 2022-2025, the annual bill increase is limited by the OEB to be less than the rate of inflation.

- At the end of the 5-year plan, the typical mid-sized business customer would see the distribution portion of their electricity bill increase by $105.39.
- As a result, the distribution charges on the typical mid-sized business customer's monthly bill would increase from $747.52 in 2020 to $852.91 by 2025.

Estimated Typical Mid-Sized Business Annual Increase in Monthly Bill (5 year forecast)

	Year	Average Mid-Sized Business Bill	Distribution Portion of Bill	Incremental Rate Change	% Change * (on distribution portion of bill)
Current Rate	2019	$11,661.27	$738.65		
Budgeted Rate	2020	$11,876.06	$747.52	$8.87	1.20%
Forecast for next rate period	2021	$11,948.38	$813.17	$65.65	8.78%
	2022	$12,127.61	$822.92	$9.76	1.20%
	2023	$12,309.52	$832.80	$9.88	1.20%
	2024	$12,494.17	$842.79	$9.99	1.20%
	2025	$12,681.58	$852.91	$10.11	1.20%
				$105.39	

*** These estimates are preliminary, and are subject to your feedback as the business plan is finalized .**

Q16. Considering what you know about Niagara Peninsula Energy's draft plan – which would see the typical mid-sized business customer's distribution portion of their bill increase by $105.39 over the 5-year period – which of the following best represents your point of view?

- ☐ NPEI should improve service, as discussed on the previous pages, even if that means an increase that exceeds $105.39 over the 5-year period
- ☐ NPEI should maintain a $105.39 increase to deliver a program that focuses on the priorities of its draft plan over the 5-year period.
- ☐ NPEI should keep increases below $105.39, even if that could mean reductions in service over the 5-year period.
- ☐ Other [Please specify]
- ☐ Don't know

Q17. Thinking about your answer to the previous question, why do you feel that NPEI should take that approach over the 2021-2025 period? (Optional) [OPEN]

Q18. Do you have any final comments regarding NPEI or the customer engagement that you just completed? (Optional) [OPEN]

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Designing Rates

Potential changes to fixed versus variable distribution rates

In recent conversations with mid-sized and large business customers, the topic of cost certainty regarding distribution rates has been raised.

Currently, distribution rates for customers, like yourself, are based on a 15% fixed and 85% variable rate. This means that 85% of your distribution charges are largely based on how much electricity you use.

In order to improve cost certainty, some customers have expressed a desire to move to a more fixed distribution rate. In its current draft plan, NPEI is proposing to increase the fixed portion of the distribution charge to 21%. Not only does this create more cost certainty for customers, but it also provides revenue certainty for NPEI to operate and maintain the distribution system

For customers who have predictable electricity usage habits, this change likely wouldn't have much of an impact, while creating more certainty for those whose electricity usage fluctuates more regularly.

NPEI is looking to understand what fixed-variable split you would like to see the utility use over the next 5-years and beyond.

Which of the following options do you prefer?

Option	Fixed-Variable Split	Expected Fixed Versus Variable Charge
Status Quo	15% fixed; 85% variable	Total distribution charge for a typical mid-sized business customer would be $813.37 in 2021 • $118.75 fixed monthly distribution charge • $3.86 per kW variable charge
Included in Draft Plan	21% fixed; 79% variable	Total distribution charge for a typical mid-sized business customer would be $813.17 in 2021 • $161.17 fixed monthly distribution charge • $3.62 per kW variable charge
Higher Fixed Distribution Charge	33% fixed; 77% variable	Total distribution charge for a typical mid-sized business customer would be $813.56 in 2021 • $256.15 fixed monthly distribution charge • $3.10 per kW variable charge

Additional Feedback (Optional)

About you

More about your organization

The following questions are for statistical purposes only. This information is used to segment and group similar people together when the survey results are analysed.

Q19. To the best of your knowledge, does your organization receive electrical service via overhead wires, underground cables?

- Overhead wires
- Underground cables
- Don’t know

Q19b. Have you experienced any power outages at your organization in the past 12 months which lasted longer than one minute?

- No outages
- 1 outage
- 2 outages
- 3 or more outages
- Don’t know

To what extent do you agree or disagree with the following statements?

Q20. The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.

- Strongly agree
- Somewhat agree
- Somewhat disagree
- Strongly disagree
- Don’t know/No opinion

Q21. Customers are well served by the electricity system in Ontario.

- Strongly agree
- Somewhat agree
- Somewhat disagree
- Strongly disagree
- Don’t know/No opinion

About you

More about your organization

Q22. As part of your job, are you in charge of managing or overseeing your organization's electricity or hydro bill?

- Yes
- No
- Don't know

Q23. Which of the following best describes the sector in which your business operates?

- Commercial
- Manufacturing/Industrial
- Data Centre
- Hospitality
- Restaurant/Tavern
- Retail
- Warehouse
- Other (Please specify)
- Prefer not to say

Q24. Including yourself, how many people work at your organization?

- OPEN
- Prefer not to say

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Final Thoughts

Feedback on Niagara Peninsula Energy's Consultation

Niagara Peninsula Energy values your feedback. This is the first time the utility has conducted a review about its upcoming plans in this type of format.

Q25. Overall, did you have a favourable or unfavourable impression of the consultation you just completed?

- Very favourable
- Somewhat favourable
- Somewhat unfavourable
- Very unfavourable
- Don't know

Q26. In this consultation, do you feel that NPEI provided too much information, not enough, or just the right amount?

- Too little information
- Just the right amount of information
- Too much information

Q27. Was there any content missing that you would have liked to have seen included in this consultation?

- None

Q28. Is there anything that you would still like answered?

- None

Appendix 1-28

Handouts for Residential and Small Business Focus Group meetings

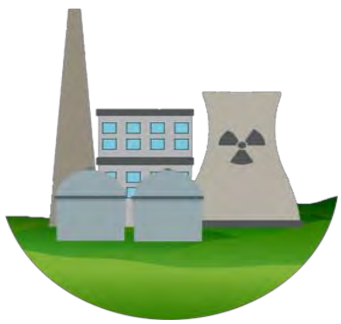
Niagara Peninsula Energy's Role in Ontario's Electricity System

Ontario's electricity system is owned and operated by public, private and municipal corporations across the province. It is made up of three key components: **generation**, **transmission** and **distribution**.

1 Generation

Where electricity comes from.

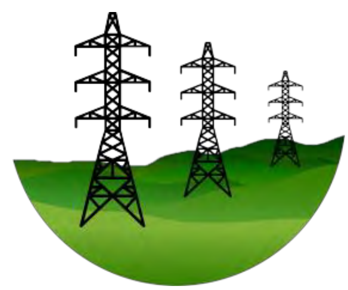
Ontario's electricity is generated by nuclear, natural gas, hydroelectric and renewable technologies such as wind and solar. In Ontario, 70% of electricity is generated by *Ontario Power Generation*, which has generation stations across the province.



2 Transmission

Electricity travels across Ontario.

Once electricity is generated, it must be transported to urban and rural areas across the province. This happens by way of high voltage transmission lines that serve as highways for electricity. The province has more than 30,000 kilometres of transmission lines, most of which is owned and operated by *Hydro One*.



niagara peninsula energy Inc. Your Local Utility

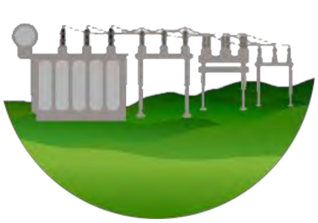
3 Local Distribution

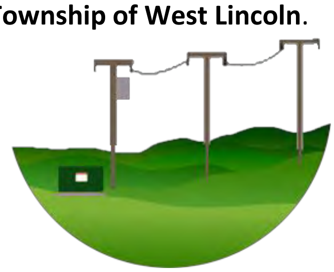
Delivering power to homes and businesses in your community.

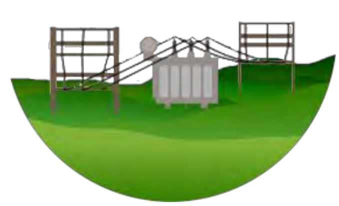
Niagara Peninsula Energy (NPEI) is responsible for the last step of the journey: distributing electricity to customers through its distribution system. This local distribution system includes transformer stations that decrease the voltage of the electricity so it can be used safely in your home or business.

There are approximately 1,451 km of overhead power lines and 573 km of underground cable. Through this distribution network, Niagara Peninsula Energy delivers electricity to more than 55,300 homes and businesses.

Niagara Peninsula Energy Inc. is jointly owned by the **City of Niagara Falls**, the **Town of Lincoln**, the **Town of Pelham** and the **Township of West Lincoln**.







Residential Electricity Bills:
Understanding where your money goes

Every item and charge on your bill is either mandated by the provincial government or approved by the Ontario Energy Board (OEB). The OEB sets electricity rates in Ontario.

For the typical residential customer, about **28%** of the electricity bill pays for **NPEI's** distribution system. The rest of the bill goes to power generation companies, transmission companies, regulatory agencies, and government taxes.

Niagara Peninsula Energy is responsible for billing customers for all of these costs, including any applicable taxes. The "Delivery" charge pays for both the cost of transmission and the cost of distribution. **Only the distribution portion is retained by NPEI to pay for operating and maintaining its part of the system.**

Sample Residential Bill

NPEI Monthly Bill
(Based on consumption of 750 kWh)

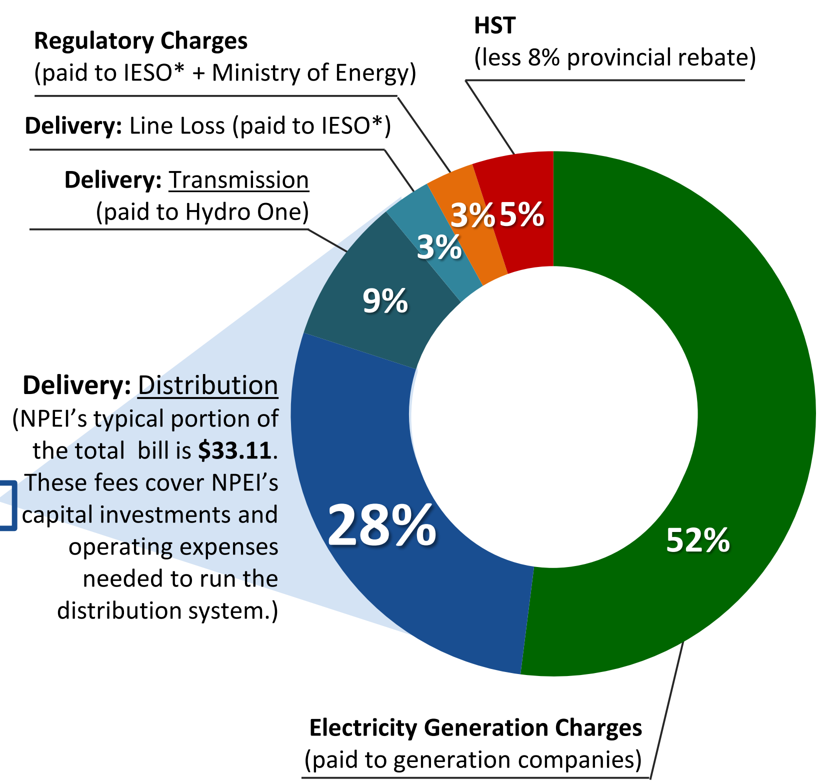
Account Number:
000 000 000 000 0000

Meter Number:
00000000

NPEI's portion:
$33.11

Your Electricity Charges	
Electricity	
Off-Peak @ 6.5 ¢/kWh	31.69
Mid-Peak @ 9.4 ¢/kWh	11.99
On-Peak @ 13.4 ¢/kWh	18.09
Delivery	45.15
Regulatory Charges	3.32
Total Electricity Charges	**$116.70**
HST	14.46
8% Provincial Rebate*	**(-$8.90)**
Total Amount	**$116.79**

*The Ontario government is providing a rebate on your electricity costs equal to the provincial portion of the HST



* IESO = Independent Electricity System Operator.

How are electricity rates determined in Ontario?

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Niagara Peninsula Energy (NPEI) is funded by the distribution rates paid by its customers. Periodically, NPEI is required to file an application with the OEB to determine the funding available to operate and maintain the distribution system. NPEI must submit evidence to justify the amount of funding it needs to safely and reliably distribute electricity to its customers.

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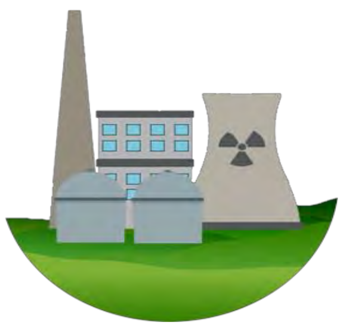

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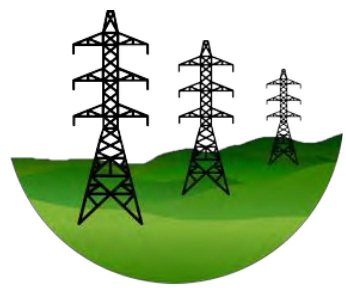


3 Local Distribution

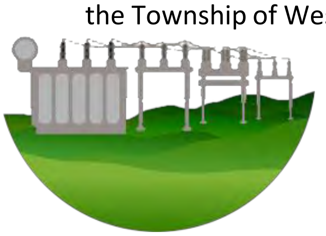
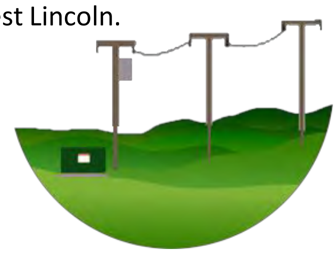
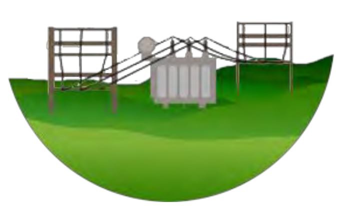
Delivering power to homes and businesses across the City of Niagara Falls, Town of Lincoln, Town of Pelham and Township of West Lincoln.

npe niagara peninsula energy Inc. *Your Local Utility*

Niagara Peninsula Energy is responsible for the last step of the journey: distributing electricity to customers through its distribution system. This local distribution system includes transformer stations that decrease the voltage of the electricity so it can be used safely in your home or business.

There are approximately 1,451 km of overhead power lines and 573 km of underground cable. Through this distribution network, Niagara Peninsula Energy delivers electricity to more than 55,300 homes and businesses.

Niagara Peninsula Energy Inc. is jointly owned by Niagara Falls Holding Corporation and Peninsula West Power Inc. Niagara Falls Holding Corp. is wholly owned by the City of Niagara Falls. Peninsula West Power Inc., which is also a Holding Company, is jointly owned by the Town of Lincoln, the Town of Pelham and the Township of West Lincoln.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Understanding where your money goes

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Niagara Peninsula Energy is responsible for billing customers for all of these costs, including any applicable taxes. The "Delivery" charge pays for both the cost of transmission and the cost of distribution. **Only the distribution portion is retained by Niagara Peninsula Energy to pay for operating and maintaining its part of the system.**

Sample Small Business Bill

Niagara Peninsula Energy Monthly Bill

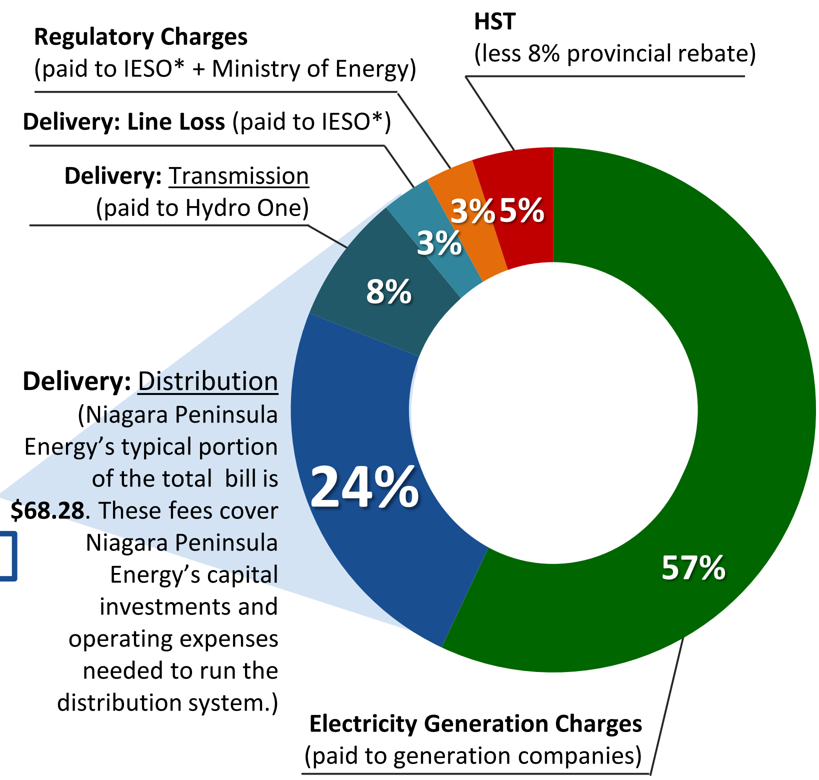
Account Number:
000 000 000 000 0000

Meter Number:
00000000

Niagara Peninsula Energy's portion: **$68.28**

Your Electricity Charges	
Electricity	
Off-Peak @ 6.5 ¢/kWh	84.50
Mid-Peak @ 9.4 ¢/kWh	31.96
On-Peak @ 13.4 ¢/kWh	48.24
Delivery	98.97
Regulatory Charges	8.42
Total Electricity Charges	**$272.10**
HST	35.37
8% Provincial Rebate*	(-$21.77)
Total Amount	**$285.70**

*The Ontario government is providing a rebate on your electricity costs equal to the provincial portion of the HST



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Niagara Peninsula Energy is funded by the distribution rates paid by its customers. Periodically, Niagara Peninsula Energy is required to file an application with the OEB to determine the funding available to operate and maintain the distribution system. Niagara Peninsula Energy must submit evidence to justify the amount of funding it needs to safely and reliably distribute electricity to its customers.

Appendix 1-29

2018 Scorecard and MD&A (Management Discussion & Analysis)

Scorecard - Niagara Peninsula Energy Inc.

8/14/2019

Performance Outcomes	Performance Categories	Measures		2014	2015	2016	2017	2018	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		91.00%	91.40%	92.70%	91.48%	93.33%	↑	90.00%	
		Scheduled Appointments Met On Time		95.10%	95.70%	99.80%	98.34%	98.89%	↑	90.00%	
		Telephone Calls Answered On Time		81.60%	82.70%	83.00%	87.99%	85.87%	↑	65.00%	
	Customer Satisfaction	First Contact Resolution		93%	94%	94%	92%	91%			
		Billing Accuracy		99.58%	99.28%	99.74%	99.46%	99.06%	↓	98.00%	
		Customer Satisfaction Survey Results		87%	87%	86%	86%	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%			
		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	0	→		0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000	→		0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		3.69	2.05	1.52	1.37	1.98	↓		2.58
		Average Number of Times that Power to a Customer is Interrupted [2]		1.51	1.42	1.38	1.55	1.65	↑		1.30
	Asset Management	Distribution System Plan Implementation Progress		95.2%	94.55%	95.97%	100.69%	99.27%			
	Cost Control	Efficiency Assessment		3	3	3	3	3			
		Total Cost per Customer [3]		$742	$744	$747	$741	$755			
		Total Cost per Km of Line [3]		$19,458	$19,871	$19,980	$20,285	$20,745			
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%			74.44 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time			100.00%	66.67%	100.00%	100.00%			
		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)		1.86	1.90	1.84	1.59	1.44			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		0.89	0.82	1.01	0.97	0.92			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.58%	9.30%	9.30%	9.30%	9.30%			
			Achieved	4.89%	8.96%	6.86%	3.57%	5.03%			

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 new 2015-2020 Conservation First Framework.

Legend:
5-year trend
↑ up ↓ down → flat
Current year
target met target not met

2018 Scorecard Management Discussion and Analysis ("2018 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 2018 Scorecard MD&A:

http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf

Scorecard MD&A - General Overview

- In 2018, Niagara Peninsula Energy Inc. (NPEI) met or exceeded all scorecard performance targets with the exception of the *Average Number of Times that Power to a Customer is Interrupted*. 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.

  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 2018 is 1.98, 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 2018 is 1.65, which represents a slight increase over 2017 (2017 = 1.55) and is outside the target of 1.30. A significant factor contributing to the increase in the average number of interruptions in 2018 are outages due to two high wind events that impacted the Niagara region on April 4, 2018 (affecting 11,052 of NPEI's customers) and on May 4, 2018 (affecting 9,767 of NPEI's customers). On both of these dates, Environment Canada issued a warning about strong winds, which gusted up to 100 km/h in the area. Excluding the impact of the outages due to high winds on April 4, 2018 and May 4, 2018 would result in an *Average Number of Times that Power to a Customer is Interrupted* for 2018 of 1.28.

- For 2019, NPEI expects to maintain its overall scorecard performance results as compared to prior years. The continued level of performance is expected due to the company's budgeted major investments in its distribution system reliability and continued responsiveness to customer feedback.

Service Quality

- **New Residential/Small Business Services Connected on Time**

  In 2018, NPEI connected 93.33% of 465 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 Ontario Energy Board (OEB). This is a slight increase over the previous year (2017 = 91.48%) 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 898 appointments with its customers in 2018 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 98.89% of these appointments on time in 2018, which is comparable to 2017 (98.34%) and exceeds the industry target of 90%.

- **Telephone Calls Answered On Time**

  In 2018, NPEI's Customer Service Representatives received over 42,500 calls from its customers, which equals 171 calls per working day. A Customer Service representative answered a call in 30 seconds or less in 85.87% of these calls, which is comparable to 2017 (87.99%) 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 91% in 2018, which is comparable to 2017 (2017 = 92%). 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 2018, NPEI issued more than 664,000 bills and achieved a billing accuracy of 99.06%. This represents a slight decline over the prior year (2017 = 99.46%) 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 scorecard, 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%.

- **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**

  NPEI reported no serious electrical incidents involving its equipment and the general public. The result was a total of zero (0) incidents with a rate of 0.000 incidents per 1,000 km of line for 2018.

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/Total 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 2018 average number of hours that power to a customer was interrupted is 1.98 (2017 = 1.37). NPEI's target for 2018 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 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. For example, in 2012 and 2013 the Murray TS 3M30 feeder was a significant contributor to both SAIDI and SAIFI. A capital project was executed to correct this deficiency by reducing feeder exposure and introducing redundant supply to the area. Another capital project was executed in 2014 which was selected for execution based on cost/risk-differential analysis in order to mitigate reliability issues on the Vineland DS 4501F1 feeder. This circuit was a significant contributor to SAIDI and SAIFI in 2014. Implementation of this project reduced feeder exposure by an additional point of supply to the area, created more system loops and rebuilt plant that was at end of life.

- NPEI will continue to trend feeder performance and evaluate technical alternatives to correct deficiencies. During 2017-2018, NPEI competed a multi-year project which provides a tie point to a second source of supply to the Jordan area from the NWTS M5. This area was previously serviced by a radial supply from the Vineland 4501F1 feeder which has experienced degradation in SAIDI and SAIFI due to lack of redundancy. The total cost of the multi-year implementation was $1.4M.

- 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/Total 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 2018 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 Cost-of-Service Rate Application), excluding the impact of Major Events. NPEI's SAIFI result for 2018 is 1.65, which represents a slight increase over 2017 (2017 = 1.55).

- A significant factor contributing to the increase in the average number of interruptions in 2018 are outages due to two high wind events that impacted the Niagara region on April 4, 2018 (affecting 11,052 of NPEI's customers) and on May 4, 2018 (affecting 9,767 of NPEI's customers). On both of these dates, Environment Canada issued a warning about strong winds, which gusted up to 100 km/h in the area. Excluding the impact of the outages due to high winds on April 4, 2018 and May 4, 2018 would result in an Average Number of Times that Power to a Customer is Interrupted for 2018 of 1.28.

- NPEI is taking action to maintain its system reliability. NPEI has conducted a detailed review of its distribution assets and prepared a comprehensive plan, which provides for the renewal of its distribution system over the period 2015 - 2019. 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 new performance measure instituted 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 per the DSP. NPEI filed its DSP with its Cost of Service rate application for 2015. NPEI achieved 99.27% (2017 = 100.69%) completion at December 31, 2018 of its 2018 capital budget.

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 2018, 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 2018, 39.4% (26 distributors) of the Ontario distributors were ranked as “average efficiency”; 40.9% (27 distributors) were ranked as “more efficient”; 19.7% (13 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 2018 is $755 /customer which is a 1.9% increase over 2017 (2017=$741 /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 and the renewal and growth of the distribution system, have all contributed to increased operating and capital costs. 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 initiatives 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. NPEI’s 2018 rate is $20,745 per km of line, a 2.3% increase over 2017 (2017=$20,285 per km). See above cost per customer section for cost drivers commentary. 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 is energy savings of 74.44 GWh to be achieved over the six-year period. At the end of 2018 which is the fourth year of the new framework, NPEI has achieved 72.0% of the total six-year target. On March 20, 2019, the Minister of Energy, Northern Development and Mines issued a directive to the IESO that concluded the Conservation First Framework.

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 2018, NPEI completed 3 CIAs for renewable generation facilities, all within the prescribed 60-day timeframe.

- **New Micro-Embedded Generation Facilities Connected On Time**

In 2018, NPEI connected 23 new micro-embedded generation facilities (microFIT or 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 2018 is 1.44 (2017 = 1.59).

- **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 2018 is 0.92 (2017 = 0.97). 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 interim 2015 rates were based on a Working Capital Allowance (WCA) placeholder of 13%. NPEI was directed by the OEB to file a lead/lag study with its 2016 Rate Application. The final Board-approved WCA was 10.48%. As a result, NPEI had a 2015 Interim Rate Rider that repaid the difference between the placeholder and final WCA percentages, which was in effect from May 2016 to April 2017.

  - NPEI's regulated rate of return achieved in 2018 is 5.03% (2017 = 3.57%). The rate of return achieved in 2018 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 distribution operations expense, due to succession planning and a higher level of overhead operations expense.
    - Increased billing expenses, due to succession planning, higher meter reading costs and increased hardware and software maintenance expenses.
    - Increased general and administrative expenses due to a new cyber security program and succession planning.

  - NPEI is scheduled to file its next Cost-of-Service rate application with the OEB in April 2020 for rates effective January 1, 2021.

Note to Readers of 2018 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.

Appendix 1-30

2019 Forecast Scorecard Results

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%	96.76%			
		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%			
		Level of Compliance with Ontario Regulations 22/04	C	C	C	C	C			C
		Serious Electrical Incident Index – Number of General Public Incidents	0	0	0	0	2			0
		Serious Electrical Incident Index – Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.988/1000			0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted	2.05	1.52	1.37	1.98	2.03			2.58
		Average Number of Times that Power to a Customer is Interrupted	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	$744	$747	$741	$755	$793			
		Total Cost per Km of Line	$19,871	$19,980	$20,285	$20,745	$21,790			
Public Policy Responsiveness **Distributors deliver on obligation 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	17.12%	34.03%	58.78%	72.00%	NA			74.44 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time	100.00%	66.67%	100.00%	100.00%	100.00%			
		New Micro-embedded Generation Facilities Connected On Time	100.00%	100.00%	100.00%	100.00%	100.00%		90.00%	
Finance 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	2.13			
		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 rate)	9.30%	9.30%	9.30%	9.30%	9.30%			
		Profitability: Regulatory Return on Equity – Achieved	8.96%	6.86%	3.57%	5.03%	4.73%			

Appendix 1-31

Audited Financial Statements 2015 to 2019

Financial Statements of

NIAGARA PENINSULA ENERGY INC.

And Independent Auditors' Report thereon
Year ended December 31, 2019

KPMG LLP
80 King Street, Suite 620
St. Catharines ON L2R 7G1
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Tel 905-685-4811
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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, 2019
- 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, 2019, 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.

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.

KPMG

- 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.

- 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 22, 2020

NIAGARA PENINSULA ENERGY INC.

Statement of Financial Position

Year ended December 31, 2019

	Note	2019	2018
Assets			
Current assets			
Cash		$ 11,885,847	$ 8,817,939
Accounts receivable	4	19,752,756	15,391,716
Due from related parties	18	8,656	12,231
Unbilled revenue		13,805,772	13,917,403
Income taxes receivable		784,450	472,515
Materials and supplies	5	1,444,523	1,411,917
Prepaid expenses		1,309,693	1,227,187
Total current assets		48,991,697	41,250,908
Non-current assets			
Property, plant and equipment	6	185,354,461	177,222,866
Intangible assets	7	547,794	672,117
Deferred tax asset	8	10,654,385	9,320,721
Total non-current assets		196,556,640	187,215,704
Total assets		245,548,337	228,466,612
Regulatory balances	9	8,489,223	9,589,744
Total assets and regulatory balances		**$ 254,037,560**	**$238,056,356**

NIAGARA PENINSULA ENERGY INC.

Statement of Financial Position

Year ended December 31, 2019

	Note	2019	2018
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	10	$ 19,657,570	$ 16,434,031
Long-term debt due within one year	11	1,044,472	11,123,823
Customer deposits		1,447,363	1,267,703
Deferred revenue		1,099,095	941,208
Total current liabilities		23,248,500	29,766,765
Non-current liabilities			
Long-term debt	11	82,834,630	65,942,590
Employees' vested sick leave		63,842	66,461
Post-employment benefits	12	4,780,183	4,020,821
Deferred capital contributions		31,635,595	27,175,680
Deferred tax liability	8	13,541,389	11,403,207
Total non-current liabilities		132,855,639	108,608,759
Total liabilities		**156,104,139**	**138,375,524**
Equity			
Share capital	13	31,245,882	31,245,882
Contributed surplus		25,459,207	25,459,207
Retained earnings		36,257,549	36,333,330
Total equity		**92,962,638**	**93,038,419**
Total liabilities and equity		**249,066,777**	**231,413,943**
Regulatory balances	9	4,970,783	6,642,413
Subsequent event	20		
Total liabilities, equity and regulatory balances		**$ 254,037,560**	**$ 238,056,356**

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, 2019, with comparative information for 2018

	Note	2019	2018
Revenue			
Distribution revenue		$ 30,714,720	$ 30,264,821
Other		2,435,170	2,752,203
		33,149,890	33,017,024
Sale of energy		143,721,440	134,510,028
Total revenue	14	176,871,330	167,527,052
Operating expenses			
Distribution and maintenance		7,632,814	7,239,770
Utilization		265,007	287,479
Billing and collecting expenses		6,167,740	5,832,207
Administration and general		5,452,330	5,151,062
Depreciation and amortization		7,818,837	7,449,739
Depreciation expense on fair value bump in amalgamation		1,046,675	1,063,804
	15	28,383,403	27,024,061
Cost of power purchased		144,376,276	138,155,453
Total expenses		172,759,679	165,179,514
Income from operating activities		**4,111,651**	**2,347,538**
Finance income	16	225,055	260,255
Finance costs	16	(2,673,955)	(2,786,580)
Income (loss) before income taxes		1,662,751	(178,787)
Current income tax recovery	8	353,819	179,925
Deferred income tax expense	8	(926,138)	(1,140,157)
Net income (loss) for the year		**1,090,432**	**(1,139,019)**
Net movement in regulatory balances, net of tax			
Net movement in regulatory balances		602,424	3,773,480
Income tax		(368,637)	715,431
	9	**233,787**	**4,488,911**
Net income and net movement in regulatory balances		**1,324,219**	**3,349,892**
Other comprehensive income			
Items that will not be reclassified to profit or loss:			
Remeasurements of post-employment benefits, net of tax		337,322	–
Net movement in regulatory balances, net of tax		(337,322)	–
Other comprehensive income for the year		–	–
Total comprehensive income for the year		**$ 1,324,219**	**$ 3,349,892**

See accompanying notes to the financial statements.

NIAGARA PENINSULA ENERGY INC.

Statement of Changes in Equity

Year ended December 31, 2019, with comparative information for 2018

	Share capital	Contributed surplus	Retained earnings	Total
Balance at January 1, 2018	$ 31,245,882	$ 25,459,207	$ 34,383,438	$ 91,088,527
Net income and net movement in regulatory balances	–	–	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**
Balance at January 1, 2019	$ 31,245,882	$ 25,459,207	$ 36,333,330	$ 93,038,419
Net income and net movement in regulatory balances	–	–	1,324,219	1,324,219
Dividends	–	–	(1,400,000)	(1,400,000)
Balance at December 31, 2019	**$ 31,245,882**	**$ 25,459,207**	**$ 36,257,549**	**$ 92,962,638**

See accompanying notes to the financial statements.

NIAGARA PENINSULA ENERGY INC.

Statement of Cash Flows

Year ended December 31, 2019, with comparative information for 2018

	2019	2018
Operating activities		
Net Income and net movement in regulatory balances	$ 1,324,219	$ 3,349,892
Adjustments for:		
Depreciation and amortization of property, plant and equipment	7,332,741	6,964,686
Depreciation and amortization of intangible assets	486,096	485,053
Depreciation fair value bump in amalgamation	1,046,675	1,063,804
Amortization of capital contributions	(1,002,764)	(894,004)
Contributions received from customers	5,462,680	2,538,034
Loss on disposal of property, plant and equipment	74,145	96,089
Post-employment benefits	300,420	137,421
Net finance cost	2,448,900	2,526,325
Employees' accumulated vested sick leave	(2,619)	4,734
Deferred tax expense	926,138	1,140,157
Current tax expense	(353,819)	(179,925)
	18,042,812	17,232,266
Change in non-cash operating working capital:		
Accounts receivable	(4,361,040)	(3,046,154)
Due to/from related parties	3,575	(4,002)
Unbilled revenue	111,631	1,765,300
Materials and supplies	(32,606)	143,835
Prepaid expenses	(82,506)	(230,580)
Accounts payable and accrued liabilities	3,223,539	(4,570,438)
Customer deposits	179,660	233,972
Deferred revenue	157,887	408,018
	17,242,952	11,932,217
Regulatory balances	(233,787)	(4,488,911)
Income tax paid	(148,110)	(52,714)
Income tax received	189,995	1,116,643
Interest paid	(2,673,955)	(2,786,579)
Interest received	225,055	260,255
Net cash from operating activities	14,602,150	5,980,911
Investing activities		
Purchase of property, plant and equipment	(16,585,422)	(14,697,016)
Purchase of intangible assets	(361,773)	(288,891)
Proceeds on disposal of property, plant and equipment	264	5,153
Net cash used by investing activities	(16,946,931)	(14,980,754)
Financing activities		
Dividends paid	(1,400,000)	(1,400,000)
Proceeds from long-term debt	43,600,000	10,000,000
Repayment of long-term debt	(36,787,311)	(11,513,894)
Net cash from (used by) financing activities	5,412,689	(2,913,894)
Change in cash	3,067,908	(11,913,737)
Cash, beginning of year	8,817,939	20,731,676
Cash, end of year	$ 11,885,847	$ 8,817,939

See accompanying notes to the financial statements.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements

Year ended December 31, 2019

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, 2019.

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 22, 2020.

The Corporation has adopted IFRS 16 *Leases* in these financial statements effective January 1, 2019. There was no material impact of this implementation on these financial statements as the Corporation does not enter into leasing arrangements and has determined that there are no arrangements that contain a lease.

(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, 2019

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), 6, 7 – estimation of useful lives of its property, plant and equipment and intangible assets
(iii) Note 3(i), 9 – recognition and measurement of regulatory balances
(iv) Note 3(j), 12 – measurement of defined benefit obligations: key actuarial assumptions
(v) Note 3(h), 17 – 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.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements

Year ended December 31, 2019

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, 2019

2. Basis of presentation (continued)

(e) Rate regulation (continued)

Rate setting (continued)

Distribution revenue (continued)

FDD for 2018 is 1.2% the Corporation's productivity factor is 0.0% and the stretch factor is 0.3% resulting in a net adjustment of .90% to the previous year's rates. An IRM Application was filed on October 15, 2018 for rates effective May 1, 2019. The OEB issued its Decision and Rate Order on March 28, 2019. The GDP-IPI- 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 1.20% to the previous year's rates. The 2020 IRM Application was filed on August 9, 2019 for rates effective May 1, 2020. The OEB issued its Decision and Rate Order on December 12, 2019. On April 16, 2020, the OEB issued a letter advising utilities that they have an option to defer implementation of their OEB approved May 1, 2020 rate increases to November 1, 2020. The Corporation has decided to defer its rate increase to November 1, 2020 in accordance with the OEB guidance. On April 17, 2020, the OEB has advised that the foregone revenue resulting from this deferral will be included in the rates to be implemented on November 1, 2020. The GDP-IPI- FDD for 2020 is 2.0% the Corporation's productivity factor is 0.0% and the stretch factor is 0.3% resulting in a net adjustment of 1.70% to the previous year's rates. The Corporation had intended to file its a Cost of Service Application on April 30, 2020 for January 1, 2021 rates, however, in light of the pandemic, the Corporation has decided to ask for a deferral to file their Cost of Service Application by August 31, 2020.

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.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements

Year ended December 31, 2019

3. Significant accounting policies (continued)

(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.

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.

3. Significant accounting policies (continued)

(b) Revenue recognition (continued)

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.

(d) Property, plant and equipment

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.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements

Year ended December 31, 2019

3. Significant accounting policies (continued)

(d) Property, plant and equipment (continued)

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.

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.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements

Year ended December 31, 2019

3. Significant accounting policies (continued)

(e) Intangible assets (continued)

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

(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.

NIAGARA PENINSULA ENERGY INC.

3. Significant accounting policies (continued)

(f) Impairment (continued)

(ii) Non-financial assets (continued)

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.

(g) Customer deposits

Customer deposits represent cash deposits from electricity distribution customers 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.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements

Year ended December 31, 2019

3. Significant accounting policies (continued)

(i) Regulatory balances (continued)

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.

(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, 2019

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 also include interest on post-employment benefits. 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.

(m) Leased assets

At inception of a contract, the Corporation assesses whether the contract is or contains a lease. A contract is determined to contain a lease if it provides the Corporation with the right to control the use of an identified asset for a period of time in exchange for consideration. Contracts determined to contain a lease are accounted for as leases.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements

Year ended December 31, 2019

4. Accounts receivable

	2019	2018
Trade receivables	$ 12,160,682	$ 11,819,996
Other trade receivables	3,825,240	743,596
Billable work	2,442,233	1,932,559
HST receivables	1,746,186	1,201,339
City of Niagara Falls	198,299	238,973
Town of Lincoln	37,038	47,298
Township of West Lincoln	37,258	24,864
Town of Pelham	6,839	6,337
Allowance for doubtful accounts	(701,019)	(623,246)
	$ 19,752,756	$ 15,391,716

5. Materials and supplies

No amount of inventory has been written down due to obsolescence as at December 31, 2019 (2018 - $nil).

6. Property, plant and equipment

	Land and buildings	Distribution equipment	Total
Cost or deemed cost			
Balance at January 1, 2019	$ 17,957,371	$ 192,248,789	$ 210,206,160
Additions	2,037,896	14,547,526	16,585,422
Disposals/retirements	–	(777,545)	(777,545)
Balance at December 31, 2019	$ 19,995,267	$ 206,018,770	$ 226,014,037
Balance at January 1, 2018	$ 16,932,507	$ 179,912,464	$ 96,844,971
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
Accumulated depreciation			
Balance at January 1, 2019	$ 1,586,850	$ 31,396,444	$ 32,983,294
Depreciation	325,689	8,053,727	8,379,416
Disposals/retirements	–	(703,134)	(703,134)
Balance at December 31, 2019	$ 1,912,539	$ 38,747,037	$ 40,659,576
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
Carrying amounts			
At December 31, 2019	$ 18,082,728	$ 167,271,733	$ 185,354,461
At December 31, 2018	$ 16,370,521	$ 160,852,345	$ 177,222,866

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements

Year ended December 31, 2019

6. Property, plant and equipment (continued)

At December 31, 2019, property, plant and equipment with a carrying value of $185,354,461 (2018 - $177,222,866) is 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, 2019.

7. Intangible assets

	Computer software	Land rights	Total
Cost or deemed cost			
Balance at January 1, 2019	$ 2,311,817	$ 132,776	$ 2,444,593
Additions	361,773	–	361,773
Balance at December 31, 2019	$ 2,673,590	$ 132,776	$ 2,806,366
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
Accumulated amortization			
Balance at January 1, 2019	$ 1,639,700	$ 132,776	$ 1,772,476
Amortization	486,096	–	486,096
Balance at December 31, 2019	$ 2,125,796	$ 132,776	$ 2,258,572
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
Carrying amounts			
At December 31, 2019	$ 547,794	$ –	$ 547,794
At December 31, 2018	$ 672,117	$ –	$ 672,117

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements

Year ended December 31, 2019

8. Income tax

Current tax expense

	2019	2018
Current year	$ 55,160	$ (457,677)
Adjustment for prior years	(408,979)	277,752
	$ (353,819)	$ (179,925)

Deferred tax expense

	2019	2018
Origination and reversal of temporary differences	$ 926,138	$ 1,140,157
	$ 926,138	$ 1,140,157
Deferred tax expense in OCI	$ (121,620)	$ –
	$ (121,620)	$ –

Reconciliation of effective tax rate

	2019	2018
Income before taxes	$ 1,662,751	$ (178,787)
Canada and Ontario statutory Income tax rates	26.50%	26.50%
Expected tax provision on income at statutory rates	440,629	(47,379)
Increase (decrease) in income taxes resulting from:		
Permanent differences	15,088	8,098
Adjustment of prior year taxes	(164,660)	(460)
Changes in regulatory account impacting current tax	281,262	999,972
Income tax expense	$ 572,319	$ 960,231

Significant components of the Corporation’s deferred tax balances

	2019	2018
Deferred tax assets (liabilities):		
Property, plant and equipment	$ (13,541,389)	$ (11,414,147)
Eligible capital property	8,383,434	7,201,555
Post-employment benefits	1,266,748	1,065,518
Timing difference on regulatory assets and liabilities	54,032	335,295
Other reserves	950,171	729,293
	$ (2,887,004)	$ (2,082,486)

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements

Year ended December 31, 2019

9. Regulatory balances

Reconciliation of the carrying amount for each class of regulatory balances

Regulatory deferral account debit balances		January 1, 2019	Additions	Recovery/ reversal	December 31, 2019	Remaining recovery/ reversal years
Group 1 deferred accounts	$	3,252,325	$ 582.822	$ (1,419,022)	$ 2,416,125	1 - 3
Regulatory settlement account		6,198	(393)	(1,182)	4,623	1.00
Other regulatory accounts		599,803	265,685	(38,174)	827,314	1 - 3
Income tax		5,731,418	–	(490,257)	5,241,161	*
	$	9,589,744	848,114	(1,948,635)	8,489,223	

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	2 - 4
Regulatory settlement account		309,645	1,909	(305,356)	6,198	1.33
Other regulatory accounts		450,894	148,909	–	599,803	2 - 4
Income tax		4,758,043	973,375	–	5,731,418	
	$	9,176,341	4,520,188	(4,106,785)	9,589,744	

Regulatory deferral account credit balances		January 1, 2019	Additions	Recovery/ reversal	December 31, 2019	Remaining years
Group 1 deferred accounts	$	(1,800,387)	$ (1,736,800)	$ 1,419,022	$ (2,118,165)	1 - 3
Regulatory settlement account		(2,399,407)	(450,499)	2,264,459	(585,447)	1.00
Other regulatory accounts		(923,794)	137,275	38,173	(748,346)	1 - 3
Income tax		(1,518,825)	–	–	(1,518,825)	*
	$	(6,642,413)	$ (2,050,024)	$ 3,721,654	$ (4,970,783)	

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)	2 - 4
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 - 4
Income tax		(1,260,882)	(257,943)	–	(1,518,825)	
	$	(10,717,921)	$ (3,176,517)	$ 7,252,025	$ (6,642,413)	

*The income tax balances will be recovered over the lives of the related capital assets.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements

Year ended December 31, 2019

9. 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 2019 the rate was 2.2475% (2018 - 1.8625%).

10. Accounts payable and accrued liabilities

	2019	2018
Accounts payable	$ 18,020,589	$ 15,019,613
Payroll payable	1,414,270	1,198,488
Other	220,542	214,201
City of Niagara Falls	1,324	832
Township of West Lincoln	845	897
	$ 19,657,570	$ 16,434,031

Included in accounts payable and accrued liabilities is a legal provision of $176,927 (2018 - $nil) resulting from an outstanding legal claim. The amount incurred and charged against the provision during the period was $176,927 (2018 - $nil) with reversals of $nil (2018 - $nil) during the period. The provision is measured at management's best estimate of the cash flows required to settle the obligation. The cash flows have not been discounted given that the obligation is expected to be settled in the following period.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements

Year ended December 31, 2019

11. Long-term debt

	2019	2018
Secured bank loans	$ 82,834,630	$ 40,337,500
Note payable – City of Niagara Falls	–	22,000,000
Note payable – Niagara Falls Hydro Holding Corporation	–	3,605,090
	$ 82,834,630	$ 65,942,590

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 notes to the City of Niagara Falls and Niagara Falls Hydro Holding Corporation have been paid in full as of August 2019.

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:

	2019	2018
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
Scotiabank loan - fixed rate 2.67% due September 2020. Repayment is in equal monthly installments of $37,500 plus interest	337,500	787,500
TD loan payable - interest only - fixed rate 2.633% due November 2019	–	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	10,000,000
TD loan payable - interest only - fixed rate 2.76% due August 2029	25,600,000	–
Scotiabank loan payable – interest only - fixed rate 2.698% due November 2024	10,000,000	–
Scotiabank loan payable – repayment in equal monthly installments of $76,138 including interest - interest rate 2.698% due November 2024	7,941,602	–
	$ 83,879,102	$ 51,461,323

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements

Year ended December 31, 2019

11. Long-term debt (continued)

Principal payments on the secured bank loans are as follows:

2020	$	1,044,472
2021		727,938
2022		747,292
2023		767,711
2024		14,991,689
Thereafter		65,600,000
		83,879,102
Less: current portion		(1,044,472)
Long-term portion of loan	$	82,834,630

12. 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 2019, the Corporation made employer contributions of $1,263,474 to OMERS (2018 - $1,268,470), of which $303,042 (2018 - $320,489) has been capitalized as part of PP&E and the remaining amount of $960,432 (2018 - $947,981) has been recognized in profit or loss. The Corporation estimates that a contribution of $1,288,743 to OMERS will be made during the next fiscal year.

As at December 31, 2019, OMERS had approximately 500,000 members, of whom 123 are current employees of the Corporation. The most recently available OMERS annual report is for the year ended December 31, 2019, which reported that the plan was 97% (2018 - 96%) funded, with an unfunded liability of $3.4 billion (2018 – $4.2 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.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements

Year ended December 31, 2019

12. Post-employment benefits (continued)

(b) Post-employment benefits other than pension (continued)

Reconciliation of the obligation	2019	2018
Defined benefit obligation, beginning of year	$ 4,020,821	$ 3,883,400
Included in profit or loss		
Current service cost	133,094	127,779
Past service cost	239,397	–
Interest cost	137,069	133,748
	4,530,381	4,144,927
Benefits paid	(209,140)	(124,106)
Actuarial loss at December 31, 2019	458,942	–
Defined benefit obligation, end of year	$ 4,780,183	$ 4,020,821

Actuarial assumptions	2019	2018
General inflation	2.00%	2.00%
Discount (interest) rate	3.00%	3.50%
Salary levels	3.30%	3.30%
Medical Costs	4.20%	5.96%
Dental Costs	4.50%	4.50%

A 1% increase in the assumed discount rate would result in the defined benefit obligation decreasing to $4,204,500. A 1% decrease in the assumed discount rate would result in the defined benefits obligation increasing to $5,509,000.

13. Share capital

	2019	2018
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 (2018 - $1,400), which amount to total dividends paid in the year of $1,400,000 (2018 - $1,400,000).

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements

Year ended December 31, 2019

14. Revenue from contracts with customers and other sources

	2019	2018
Revenue from contracts with customers:		
Energy sales	$ 143,721,440	$ 134,510,028
Distribution revenue	30,714,720	30,264,821
	174,436,160	164,774,849
Other revenue:		
Amortization of capital contributions	1,002,764	894,004
Miscellaneous service revenues	357,854	573,458
Interest charges on hydro sales	336,173	372,405
Pole rental revenue	504,437	252,719
Occupancy change charge	188,760	186,780
Collection and reconnection charges	85,161	92,522
	176,911,309	167,146,737
Revenue from other sources:		
CDM programs	–	437,530
Miscellaneous non-operating revenue	34,166	38,875
Loss on disposal of property, plant & equipment	(74,145)	(96,090)
	$ 176,871,330	$ 167,527,052

The following table disaggregates energy sales and distribution revenues from contracts with customers by type of customer:

	2019	2018
Revenue from contracts with customers:		
Residential	$ 58,851,579	$ 58,180,773
Commercial	19,509,656	18,283,606
Large users	94,974,608	87,279,208
Other	1,100,317	1,031,262
	$ 174,436,160	$ 164,774,849

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements

Year ended December 31, 2019

15. Operating expenses

	2019	2018
Salaries, wages and benefits	$ 11,420,992	$ 10,676,327
Materials and supplies	154,058	182,038
Vehicle expenditures	525,628	489,775
Outside purchases	7,073,430	6,853,850
Bad debt expenses	343,783	308,528
Depreciation and amortization	8,865,512	8,513,543
	$ 28,383,403	$ 27,024,061

16. Finance income and costs

	2019	2018
Finance income		
Interest income on bank deposits	$ 225,055	$ 260,255
Finance costs		
Interest expense on long-term debt	1,799,900	1,450,363
Interest expense on debt to associated companies and Town	712,462	1,221,363
Interest expense on customer deposits	24,524	15,987
Interest expense on post employment retirement benefits	137,069	98,867
	2,673,955	2,786,580
Net finance costs recognized in profit or loss	$ 2,448,900	$ 2,526,325

NIAGARA PENINSULA ENERGY INC.

17. 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 (2018 - $12,000,000) of which $11,910,187 (2018 - $11,910,187) has been drawn down. The Independent Electricity Market Operator is the beneficiary for $11,910,187 (2018 - $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, 2019, no assessments have been made.

18. 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, 2019

18. Related party transactions (continued)

(a) Outstanding balances with related parties included in Due from (to) related parties:

	2019	2018
Peninsula West Services Ltd.	$ 3,364	$ 6,939
Niagara Falls Hydro Holding Corporation	2,646	2,646
Niagara Falls Hydro Services Inc.	2,646	2,646
	$ 8,656	$ 12,231

These balances are non-interest bearing with no fixed repayment terms.

(b) Transactions with ultimate parent

	2019	2018
Revenue:		
Energy sales (at commercial rates)		
City of Niagara Falls	$ 2,745,695	$ 2,628,705
Town of Lincoln	392,510	397,365
Township of West Lincoln	245,891	192,774
Town of Pelham	78,682	79,127
	$ 3,462,778	$ 3,297,971

	2019	2018
Expenses:		
Property taxes		
City of Niagara Falls	$ 146,066	$ 145,898
Town of Lincoln	2,682	2,482
Township of West Lincoln	67,721	69,556
Town of Pelham	831	756
Water expenses		
City of Niagara Falls	7,072	9,490
Township of West Lincoln	3,493	3,783
Other miscellaneous expenses		
City of Niagara Falls	18,511	17,231
Township of West Lincoln	825	5,386
Town of Pelham	700	2,950
Town of Lincoln	200	2,353
	$ 248,101	$ 259,885

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements

Year ended December 31, 2019

18. Related party transactions (continued)

(c) Transactions with parent

	2019	2018
Revenue:		
Accounting services		
Peninsula West Power Inc.	$ 1,000	$ 1,000

(d) Transaction with companies with common ownership

	2019	2018
Revenue:		
Accounting services		
Peninsula West Services Ltd.	$ 11,194	$ 12,315

(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:

	2019	2018
Directors' fees	$ 90,190	$ 88,340
Salaries and other short-term benefits	1,950,860	1,831,402
	$ 2,041,050	$ 1,919,742

19. Financial instruments and risk management

Fair value disclosure

The carrying values of cash, 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, 2019 is $75,334,000 (2018 - $76,025,000). 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, 2019 was 2.82% (2018 - 4.34%).

19. Financial instruments and risk management (continued)

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, 2019 is $701,019 (2018 - $623,246). An impairment loss of $343,783 (2018 - $308,528) 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, 2019, approximately $999,403 (2018 - $840,695) is considered 60 days past due. The Corporation has over 56,000 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, 2019, the Corporation holds security deposits in the amount of $1,447,363 (2018 - $1,267,703).

(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.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements

Year ended December 31, 2019

19. Financial instruments and risk management (continued)

(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, 2019, 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 (2018 - $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, 2019, shareholder's equity amounts to $92,962,638 (2018 - $93,038,419) and long-term debt amounts to $83,879,102 (2018 - $77,066,413).

20. Subsequent event

Subsequent to December 31, 2019 the COVID-19 outbreak was declared a pandemic by the World Health Organization. This has resulted in governments worldwide, including the Canadian and Ontario governments, enacting emergency measures to combat the spread of the virus. These measures, which include the implementation of travel bans, self-imposed quarantine periods and social distancing, have caused material disruption to businesses globally and in Ontario resulting in an economic slowdown. Governments and central banks have reacted with significant monetary and fiscal interventions designed to stabilize economic conditions however the success of these interventions is not currently determinable. The current challenging economic climate may lead to adverse changes in cash flows, working capital levels and/or debt balances, which may also have a direct impact on the Corporation's operating results and financial position in the future. The situation is dynamic and the ultimate duration and magnitude of the impact on the economy and our business are not known at this time.

21. Comparative figures

The financial statements have been reclassified, where applicable, to conform to the presentation used in the current year.

Financial Statements of

NIAGARA PENINSULA ENERGY INC.

Year ended December 31, 2018

KPMG

KPMG LLP
80 King Street, Suite 620
St. Catharines ON L2R 7G1
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Tel 905-685-4811
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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.

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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.

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- 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.

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.

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.

Financial Statements of

NIAGARA PENINSULA ENERGY INC.

Year ended December 31, 2017

KPMG

KPMG LLP
80 King Street, Suite 620
St. Catharines ON L2R 7G1
Canada
Telephone (905) 685-4811
Fax (905) 682-2008

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Niagara Peninsula Energy Inc.:

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, 2017, and the statements of comprehensive income, changes in equity and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, 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.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform an audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the Entity's preparation and fair presentation of the financial statements 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. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

KPMG

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Niagara Peninsula Energy Inc. as at December 31, 2017, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

St. Catharines, Canada
April 17, 2018

NIAGARA PENINSULA ENERGY INC.

Statement of Financial Position
Year ended December 31, 2017

	Note	2017	2016
Assets			
Current assets			
Cash		$ 20,731,676	$ 21,563,744
Accounts receivable	5	11,144,223	14,704,474
Due from related parties	19	8,229	5,982
Unbilled revenue		15,682,703	17,220,601
Income taxes receivable		1,356,520	1,757,970
Materials and supplies	6	1,555,752	1,364,874
Prepaid expenses		996,607	1,111,429
Total current assets		51,475,710	57,729,074
Non-current assets			
Property, plant and equipment	7	170,655,581	164,339,398
Intangible assets	8	868,280	457,076
Deferred tax asset	9	9,320,721	9,116,970
Total non-current assets		180,844,582	173,913,444
Total assets		**232,320,292**	**231,642,518**
Regulatory balances	10	9,176,341	7,738,903
Total assets and regulatory balances		**$ 241,496,633**	**$ 239,381,421**

NIAGARA PENINSULA ENERGY INC.

Statement of Financial Position
Year ended December 31, 2017

	Note	2017	2016
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	11	$ 19,803,130	$ 18,437,305
Long-term debt due within one year	12	11,513,894	11,466,355
Customer deposits		1,033,731	1,542,795
Deferred revenue		533,190	713,947
Total current liabilities		32,883,945	32,160,402
Non-current liabilities			
Long-term debt	12	67,066,413	68,580,307
Employees' vested sick leave		61,727	55,182
Post-employment benefits	13	3,883,400	2,619,248
Deferred capital contributions		25,531,650	23,884,357
Deferred tax liability	9	10,263,050	9,064,452
Total non-current liabilities		106,806,240	104,203,546
Total liabilities		**139,690,185**	**136,363,948**
Equity			
Share capital	14	31,245,882	31,245,882
Contributed surplus		25,459,207	25,459,207
Retained earnings		34,383,438	33,861,775
Total equity		**91,088,527**	**90,566,864**
Total liabilities and equity		**230,778,712**	**226,930,812**
Regulatory balances	10	10,717,921	12,450,609
Total liabilities, equity and regulatory balances		**$ 241,496,633**	**$ 239,381,421**

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, 2017, with comparative information for 2016

	Note	2017	2016
Revenue			
Distribution revenue		$ 28,721,728	$ 25,938,435
Other	15	1,938,837	2,210,670
		30,660,565	28,149,105
Sale of energy		146,426,517	165,669,063
Total revenue		177,087,082	193,818,168
Operating expenses			
Distribution and maintenance		7,291,535	6,494,744
Utilization		262,109	219,410
Billing and collecting expenses		5,706,034	5,340,057
Administration and general		5,160,744	5,204,616
Depreciation and amortization		6,937,288	6,462,385
Depreciation expense on fair value bump in amalgamation		1,043,979	1,084,545
	16	26,401,689	24,805,757
Cost of power purchased		147,388,601	164,516,077
Total expenses		173,790,290	189,321,834
Income from operating activities		**3,296,792**	**4,496,334**
Finance income	17	225,113	108,114
Finance costs	17	(2,737,311)	(2,427,543)
Income before income taxes		**784,594**	**2,176,905**
Income tax expense	9	(1,508,855)	(238,033)
Net (loss) income for the year		**(724,261)**	**1,938,872**
Net movement in regulatory balances, net of tax			
Net movement in regulatory balances	10	1,883,858	1,517,897
Income tax		762,066	616,249
		2,645,924	**2,134,146**
Net income for the year, net movement in regulatory balances and comprehensive income		**1,921,663**	**4,073,018**
Other comprehensive income			
Items that will not be reclassified to profit or loss:			
Remeasurements of post-employment benefits	13	524,202	0
Net movement in regulatory balances, net of tax		(524,202)	0
Other comprehensive income for the year		0	0
Total comprehensive income for the year		**$ 1,921,663**	**$ 4,073,018**

See accompanying notes to the financial statements.

NIAGARA PENINSULA ENERGY INC.

Statement of Changes in Equity
Year ended December 31, 2017, with comparative information for 2016

	Share capital	Contributed surplus	Retained earnings	Total
Balance at January 1, 2016	$ 31,245,882	$ 25,459,207	$ 31,188,757	$ 87,893,846
Net Income, net movement in regulatory balances and comprehensive income	0	0	4,073,018	4,073,018
Dividends	0	0	(1,400,000)	(1,400,000)
Balance at December 31, 2016	**$ 31,245,882**	**$ 25,459,207**	**$ 33,861,775**	**$ 90,566,864**
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	0	0	1,921,663	1,921,663
Dividends	0	0	(1,400,000)	(1,400,000)
Balance at December 31, 2017	**$ 31,245,882**	**$ 25,459,207**	**$ 34,383,438**	**$ 91,088,527**

See accompanying notes to the financial statements.

NIAGARA PENINSULA ENERGY INC.

Statement of Cash Flows
Year ended December 31, 2017, with comparative information for 2016

	2017	2016
Operating activities		
Net Income and net movement in regulatory balances	$ 1,921,663	$ 4,073,018
Adjustments for:		
Depreciation and amortization	6,637,596	6,232,159
Depreciation and amortization intangible assets	299,692	230,226
Depreciation fair value bump in amalgamation	1,043,979	1,084,545
Amortization of capital contributions	(824,191)	(738,438)
Contributions received from customers	2,471,484	4,031,451
Net loss on disposal of property, plant and equipment	94,957	8,384
Proceeds on disposal of property, plant and equipment	129,406	-
Post-employment benefits	550,952	115,148
Interest expense	2,512,198	2,319,429
Employees’ accumulated vested sick leave	6,545	2,954
Deferred tax expense	1,183,845	426,904
Current tax expense	325,010	(188,871)
	16,353,136	17,596,909
Change in non-cash operating working capital:		
Accounts receivable	3,560,251	(97,877)
Due to/from related parties	(2,247)	(13,337)
Unbilled revenue	1,537,898	162,777
Materials and supplies	(190,878)	134,073
Prepaid expenses	114,822	1,082
Accounts payable and accrued liabilities	1,365,825	(1,198,581)
Customer deposits	(509,064)	9,757
Deferred revenue	(180,757)	(116,726)
	22,048,986	16,478,077
Regulatory balances	(2,645,924)	(2,134,146)
Income tax paid	(935,000)	(1,291,186)
Income tax received	1,011,440	28,364
Interest paid	(2,737,311)	(2,427,543)
Interest received	225,113	108,114
Net cash from operating activities	**16,967,304**	**10,761,680**
Investing activities		
Purchase of property, plant and equipment	(14,222,121)	(15,083,955)
Purchase of intangible assets	(710,896)	(342,477)
Net cash used by investing activities	**(14,933,017)**	**(15,426,432)**
Financing activities		
Dividends paid	(1,400,000)	(1,400,000)
Proceeds from long-term debt	10,000,000	20,000,000
Repayment of long-term debt	(11,466,355)	(1,420,498)
Net cash from financing activities	**(2,866,355)**	**17,179,502**
Change in cash	(832,068)	12,514,750
Cash, beginning of year	21,563,744	9,048,994
Cash, end of year	**$ 20,731,676**	**$ 21,563,744**

See accompanying notes to the financial statements.

NIAGARA PENINSULA ENERGY INC.

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, 2017.

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, 2018.

(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.

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),7,8 – estimation of useful lives of its property, plant and equipment and intangible assets
(iii) Note 3(i),10 – recognition and measurement of regulatory balances
(iv) Note 13 – measurement of defined benefit obligations: key actuarial assumptions
(v) Note 18 – 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.

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.

2. Basis of presentation (continued)

(e) Rate regulation (continued)

Rate setting (continued)

Distribution revenue (continued)

FDD for 2018 is 1.2% the Corporation's productivity factor is 0.0% and the stretch factor is 0.3% resulting in a net adjustment of 0.9% 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 are classified as loans and receivables and all financial liabilities are classified as other liabilities. These financial instruments 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

Revenue from the sale and distribution of electricity is recognized as the electricity is delivered to customers on the basis of cyclical meter readings and estimated customer usage since the last meter reading date to the end of the year. 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.

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.

Certain customers and developers are required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. 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.

(d) Property, plant and equipment

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.

NIAGARA PENINSULA ENERGY INC.

3. Significant accounting policies (continued)

(d) Property, plant and equipment (continued)

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.

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

NIAGARA PENINSULA ENERGY INC.

3. Significant accounting policies (continued)

(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

(f) Impairment

(i) Financial assets measured at amortized cost

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss is calculated as the difference between an asset’s carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate. Interest on the impaired assets continues to be recognized through the unwinding of the discount. Losses are recognized in profit or loss. An impairment loss is reversed through profit or loss if the reversal can be related objectively to an event occurring after the impairment loss was recognized.

(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.

3. Significant accounting policies (continued)

(f) Impairment (continued)

(ii) Non-financial assets (continued)

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.

(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.

NIAGARA PENINSULA ENERGY INC.

3. Significant accounting policies (continued)

(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.

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, 2017

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.

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.

Revenue Recognition

The IASB has issued IFRS 15, Revenue from Contracts with Customers ("IFRS 15"). IFRS 15 replaces IAS 11 Construction Contracts, IAS 18 Revenue and various interpretations and establishes principles regarding the nature, amount, timing and uncertainty of revenue arising from contracts with customers. The standard requires entities to recognize revenue for the transfer of goods or services to customers measured at the amounts an entity expects to be entitled to in exchange for those goods or services. IFRS 15 is effective for annual periods beginning on or after January 1, 2018. The Corporation will adopt IFRS 15 and the clarifications in its financial statements for the annual period beginning January 1, 2018. The Corporation does not expect the standard to have a material impact on the financial statements.

Financial Instruments

In July 2014, the IASB issued a new standard, IFRS 9 Financial Instruments, which will replace IAS 39 Financial Instruments: Recognition and Measurement. IFRS 9 is effective for annual periods beginning on or after January 1, 2018 and must be applied retrospectively. The Corporation will adopt IFRS 9 in its financial statements for the annual period beginning on January 1, 2018. The Corporation does not expect the standard to have a material impact on the financial statements.

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 IAS 17 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.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2017

5. Accounts receivable

	2017	2016
Trade receivables	$ 9,172,417	$ 13,469,077
Other trade receivables	445,896	0
Billable work	2,005,574	1,556,981
City of Niagara Falls	34,300	203,504
Town of Lincoln	37,918	0
Township of West Lincoln	0	10,209
Town of Pelham	7,229	8,971
Allowance for doubtful accounts	(559,111)	(544,268)
	$ 11,144,223	$ 14,704,474

6. Materials and supplies

No amount of inventory has been written down due to obsolescence as at December 31, 2017 (2016 - $0).

7. Property, plant and equipment

	Land and buildings	Distribution equipment	Total
Cost or deemed cost			
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	0	(988,873)	(988,873)
Balance at December 31, 2017	$ 16,932,507	$ 179,912,464	$ 196,844,971
Balance at January 1, 2016	$ 16,476,747	$ 152,784,881	$ 169,261,628
Additions	52,753	15,031,202	15,083,955
Disposals/retirements	0	(733,860)	(733,860)
Balance at December 31, 2016	$ 16,529,500	$ 167,082,223	$ 183,611,723
Accumulated depreciation			
Balance at January 1, 2017	$ 905,913	$ 18,366,412	$ 19,272,325
Depreciation	364,446	7,317,129	7,681,575
Disposals/retirements	0	(764,510)	(764,510)
Balance at December 31, 2017	$ 1,270,359	$ 24,919,031	$ 26,189,390
Balance at January 1, 2016	$ 548,324	$ 12,132,773	$ 12,681,097
Depreciation	357,589	6,959,115	7,316,704
Disposals/retirements	0	(725,476)	(725,476)
Balance at December 31, 2016	$ 905,913	$ 18,366,412	$ 19,272,325
Carrying amounts			
At December 31, 2017	$ 15,662,148	$ 154,993,433	$ 170,655,581
At December 31, 2016	15,623,587	148,715,811	164,339,398

At December 31, 2017, PP&E with a carry value of $170,655,581 (2016 - $164,339,398) 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, 2017.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2017

8. Intangible assets

	Computer software	Land rights	Total
Cost or deemed cost			
Balance at January 1, 2017	$ 1,312,031	$ 132,776	$ 1,444,807
Additions	710,896	0	710,896
Balance at December 31, 2017	$ 2,022,927	$ 132,776	$ 2,155,703
Balance at January 1, 2016	$ 969,554	$ 132,776	$ 1,102,330
Additions	342,477	0	342,477
Balance at December 31, 2016	$ 1,312,031	$ 132,776	$ 1,444,807
Accumulated amortization			
Balance at January 1, 2017	$ 854,955	$ 132,776	$ 987,731
Amortization	299,692	0	299,692
Balance at December 31, 2017	$ 1,154,647	$ 132,776	$ 1,287,423
Balance at January 1, 2016	$ 624,729	$ 132,776	$ 757,505
Amortization	230,226	0	230,226
Balance at December 31, 2016	$ 854,955	$ 132,776	$ 987,731
Carrying amounts			
At December 31, 2017	$ 868,280	$ 0	$ 868,280
At December 31, 2016	457,076	0	457,076

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2017

9. Income tax

Current tax expense

	2017	2016
Current year	$ (307,340)	$ (80,990)
Adjustment for prior years	632,350	(107,881)
	$ 325,010	$(188,871)

Deferred tax expense

	2017	2016
Origination and reversal of temporary differences	$1,183,845	$ 440,876
	$1,183,845	$ 440,876
Deferred tax expense in OCI	$ (188,988)	$ (13,972)
	$ (188,988)	$ (13,972)

Reconciliation of effective tax rate

	2017	2016
Income before taxes	$ 784,594	$ 2,176,905
Canada and Ontario statutory Income tax rates	26.50%	26.50%
Expected tax provision on income at statutory rates	207,917	576,615
Increase (decrease) in income taxes resulting from:		
Permanent differences	12,850	7,392
Adjustment of prior year taxes	649,952	(748,483)
Changes in regulatory account impacting current tax	638,136	402,243
Other	0	266
Income tax expense	$ 1,508,855	$ 238,033

Significant components of the Corporation's deferred tax balances

	2017	2016
Deferred tax assets (liabilities):		
Property, plant and equipment	$(10,263,050)	$ (9,064,452)
Cumulative eligible capital	6,765,887	6,329,355
Post-employment benefits	1,029,101	694,101
Timing difference on regulatory assets and liabilities	1,335,266	1,973,402
Other reserves	190,467	120,112
	$ (942,329)	$ 52,517

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2017

10. Regulatory balances

Reconciliation of the carrying amount for each class of regulatory balances

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	$ 0	$ 3,657,759	1.33
Regulatory settlement account	323,040	501,848	(515,243)	309,645	1.33
Other regulatory accounts	789,612	(338,718)	0	450,894	3.00
Income tax	3,721,218	1,036,825	0	4,758,043	
	$ 7,738,903	$ 1,952,681	$ (515,243)	$ 9,176,341	

Regulatory deferral account debit balances	January 1, 2016	Additions	Recovery/ reversal	December 31, 2016	Remaining recovery/ reversal years
Group 1 deferred accounts	$ 2,145,583	$ 759,450	$ 0	$ 2,905,033	2.33
Regulatory settlement account	1,129,876	3,372	(810,208)	323,040	2.33
Other regulatory accounts	657,401	166,288	(34,077)	789,612	4.00
Income tax	2,882,781	838,437	0	3,721,218	
	$ 6,815,641	$ 1,767,547	$ (844,285)	$ 7,738,903	

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	$ 0	$ (8,105,775)	1.33
Regulatory settlement account	(1,552,089)	(19,411)	1,165,453	(406,047)	1.33
Other regulatory accounts	(1,654,339)	709,122	0	(945,217)	3.00
Income tax	(986,123)	(274,759)	0	(1,260,882)	
	$ (12,450,609)	$ 567,235	$ 1,165,453	$(10,717,921)	

Regulatory deferral account credit balances	January 1, 2016	Additions	Recovery/ reversal	December 31, 2016	Remaining years
Group 1 deferred accounts	$ (6,284,132)	$(2,348,112)	$ 374,186	$ (8,258,058)	2.33
Regulatory settlement account	(4,998,884)	(255,811)	3,702,606	(1,552,089)	2.33
Other regulatory accounts	(1,614,542)	(39,797)	0	(1,654,339)	4.00
Income tax	(763,935)	(222,188)	0	(986,123)	
	$ (13,661,493)	$(2,865,908)	$ 4,076,792	$(12,450,609)	

NIAGARA PENINSULA ENERGY INC.

10. 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, 2016. These balances were included in the Corporation's IRM application in 2017 for rates effective May 1, 2018. 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, 2019. 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 2017 the rate was 1.20% (2016 - 1.10%).

11. Accounts payable and accrued liabilities

	2017	2016+
Accounts payable	$ 17,831,990	$ 16,561,845
Debt retirement charge payable to OEFC	459,406	453,312
Payroll payable	1,235,238	1,079,891
Other	274,522	340,168
City of Niagara Falls	1,020	994
Township of West Lincoln	954	1,095
	$ 19,803,130	$ 18,437,305

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2017

12. Long-term debt

	2017	2016
Secured bank loans	$ 41,461,323	$ 42,975,217
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
	$ 67,066,413	$ 68,580,307

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:

	2017	2016
TD bank term loan-fixed rate 4.58% due July 2019. Repayment is in equal monthly installments of $93,442 of interest and principal	$ 1,737,717	$ 2,754,072
Scotiabank loan-fixed rate 2.67% due September 2020. Repayment is in equal monthly installments of $37,500 plus interest	1,237,500	1,687,500
TD loan payable - interest only-fixed rate 2.80% due June 2017	0	10,000,000
TD loan payable - interest only-fixed rate 2.933% due December 2018	10,000,000	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	0
	$ 52,975,217	$ 54,441,572

Principal payments on the secured bank loans are as follows:

2018	$ 11,513,894
2019	11,123,823
2020	337,500
2021	0
2022	0
2023 – 2026	30,000,000
	52,975,217
Less: current portion	11,513,894
Long-term portion of loan	$ 41,461,323

13. 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 2017, the Corporation made employer contributions of $1,246,730 to OMERS (2016 - $1,215,948), of which $331,972 (2016 - $351,274) has been capitalized as part of PP&E and the remaining amount of $914,757 (2016 - $864,674) has been recognized in profit or loss. The Corporation estimates that a contribution of $1,271,665 to OMERS will be made during the next fiscal year.

As at December 31, 2017, 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, 2017, which reported that the plan was 94% (2016 - 93.4%) funded, with an unfunded liability of $5.4 billion (2016 – $5.7 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	2017	2016
Defined benefit obligation, beginning of year	$ 2,619,248	$ 2,504,100
Included in profit or loss		
Current service cost	109,400	104,425
Past service cost	412,700	0
Interest cost	123,500	117,631
	3,264,848	2,726,156
Benefits paid	(94,648)	(106,908)
Actuarial loss at December 31, 2017	713,200	0
Defined benefit obligation, end of year	$ 3,883,400	$ 2,619,248

Actuarial assumptions	2017	2016
General inflation	2.00%	2.00%
Discount (interest) rate	3.50%	4.80%
Salary levels	3.30%	3.10%
Medical Costs	6.20%	6.40%
Dental Costs	4.50%	4.60%

A 1% increase in the assumed discount rate would result in the defined benefit obligation decreasing to $3,423,000. 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, 2017

14. Share capital

	2017	2016
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 (2016 - $1,400), which amount to total dividends paid in the year of $1,400,000 (2016 - $1,400,000).

15. Other revenue

	2017	2016
Pole rental revenue	$ 248,747	$ 242,690
Interest charges on hydro sales	372,954	429,277
Collection & reconnection charges	117,397	270,121
Occupancy change charge	215,220	205,290
Miscellaneous service revenues	198,052	250,632
Miscellaneous non-operating revenue	63,464	98,693
Contributions received from customers	824,191	738,438
Performance incentive payments under CDM programs	(6,231)	(16,087)
Loss on disposal of property, plant & equipment	(94,957)	(8,384)
	$ 1,938,837	$ 2,210,670

16. Operating expenses

	2017	2016
Salaries, wages and benefits	$ 10,756,599	$ 9,774,533
Materials and supplies	186,612	180,476
Vehicle expenditures	305,957	304,663
Outside purchases	6,908,086	6,780,803
Bad Debt expenses	263,168	218,352
Depreciation and amortization	7,981,267	7,546,930
	$ 26,401,689	$ 24,805,757

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2017

17. Finance income and costs

	2017	2016
Finance income		
Interest income on bank deposits	$ 225,113	$ 108,114
Finance costs		
Interest expense on long-term debt	1,504,869	1,195,429
Interest expense on debt to associated companies and Town	1,221,363	1,221,363
Interest expense on customer deposits	11,079	10,494
Other	0	257
	2,737,311	2,427,543
Net finance costs recognized in profit or loss	$ 2,512,198	$ 2,319,429

18. 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 (2016 - $12,000,000) of which $11,910,187 (2016 - $11,910,187) has been drawn down. The Independent Electricity Market Operator is the beneficiary for $11,910,187 (2016 - $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, 2017, no assessments have been made.

19. 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, 2017

19. Related party transactions (continued)

(b) Outstanding balances with related parties included in Due from (to) related parties:

	2017	2016
Peninsula West Services Ltd.	$ 4,449	$ 2,742
Niagara Falls Hydro Holding Corporation	1,890	1,620
Niagara Falls Hydro Services Inc.	1,890	1,620
	$ 8,229	$ 5,982

These balances are non-interest bearing with no fixed repayment terms.

(c) Transactions with ultimate parent

	2017	2016
Revenue:		
Energy sales (at commercial rates)		
City of Niagara Falls	$ 2,685,878	$ 2,774,125
Town of Lincoln	421,009	425,707
Township of West Lincoln	206,801	234,305
Town of Pelham	93,785	55,862
	$ 3,407,473	$ 3,489,999

	2017	2016
Expenses:		
Property taxes		
City of Niagara Falls	$ 148,919	$ 209,925
Town of Lincoln	2,305	2,128
Township of West Lincoln	71,852	81,687
Town of Pelham	693	629
Water expenses		
City of Niagara Falls	11,033	11,282
Township of West Lincoln	4,877	4,224
Other miscellaneous expenses		
City of Niagara Falls	30,632	10,440
Township of West Lincoln	12,100	858
Town of Pelham	8,605	4,510
Town of Lincoln	15,000	7,200
	$ 306,016	$ 332,883

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2017

19. Related party transactions (continued)

(d) Transactions with parent

	2017	2016
Revenue:		
Accounting services		
Peninsula West Power Inc.	$ 1,000	$ 1,000

(e) Transaction with companies with common ownership

	2017	2016
Revenue:		
Accounting services		
Peninsula West Services Ltd.	$ 12,637	$ 14,657

(f) 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:

	2017	2016
Directors’ fees	$ 82,360	$ 74,650
Salaries and other short-term benefits	1,712,029	1,425,419
	$ 1,794,389	$ 1,500,069

20. Financial instruments and risk management

Fair value disclosure

The carrying values of cash and cash equivalents, accounts receivable, unbilled revenue, due from/to related parties 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, 2017 is $77,820,000 (2016 - $72,888,000). 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, 2017 was 4.27% (2016 - 3.61%).

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, 2017 is $559,111 (2016 - $544,268). An impairment loss of $263,168 (2016 - $218,352) 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, 2017, approximately $645,575 (2016 - $661,348) 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, 2017, the Corporation holds security deposits in the amount of $1,033,731 (2016 - $1,542,795).

20. 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, 2016, 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 (2016 - $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, 2017, shareholder's equity amounts to $91,088,526 (2016 - $90,566,864) and long-term debt amounts to $78,580,307 (2016 - $80,046,662).

21. Comparative figures

The financial statements have been reclassified, where applicable, to conform to the presentation used in the current year.

Financial Statements of

Niagara Peninsula Energy Inc.

Year ended December 31, 2016

KPMG

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 Board Members and Shareholders of Niagara Peninsula Energy Inc.:

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, 2016, the statement of comprehensive income, changes in equity and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, 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.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audits to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the Entity's preparation and fair presentation of the financial statements 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. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Niagara Peninsula Energy Inc. as at December 31, 2016, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

April 18, 2017

St. Catharines, Canada

NIAGARA PENINSULA ENERGY INC.

Statement of Financial Position
Year ended December 31, 2016

	Note	2016	2015
Assets			
Current assets			
Cash and cash equivalents		$ 21,563,744	$ 9,048,994
Accounts receivable	5	14,704,474	14,606,597
Due from related parties	19	5,982	0
Unbilled revenue		17,220,601	17,383,378
Income taxes receivable		1,757,970	306,277
Materials and supplies	6	1,364,874	1,498,947
Prepaid expenses		1,111,429	1,112,511
Total current assets		57,729,074	43,956,704
Non-current assets			
Property, plant and equipment	7	164,339,398	156,580,531
Intangible assets	8	457,076	344,825
Deferred tax asset	9	52,518	479,422
Total non-current assets		164,848,992	157,404,778
Total assets		**222,578,066**	**201,361,482**
Regulatory balances	10	7,527,318	6,539,918
Total assets and regulatory balances		**$ 230,105,384**	**$ 207,901,400**

NIAGARA PENINSULA ENERGY INC.

Statement of Financial Position
Year ended December 31, 2016

	Note	2016	2015
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	11	$ 18,437,305	$ 19,635,886
Due to related parties	19	0	7,355
Long-term debt due within one year	12	11,466,355	1,420,498
Customer deposits		1,542,795	1,533,038
Deferred revenue		713,947	830,673
Total current liabilities		32,160,402	23,427,450
Non-current liabilities			
Long-term debt	12	68,580,307	60,046,662
Employees' vested sick leave		55,182	52,228
Post-employment benefits	13	2,619,248	2,504,100
Deferred capital contributions		23,884,357	20,591,344
Total non-current liabilities		95,139,094	83,194,334
Total liabilities		**127,299,496**	**106,621,784**
Equity			
Share capital	14	31,245,882	31,245,882
Contributed surplus		25,459,207	25,459,207
Retained earnings		33,861,775	31,188,757
Total equity		**90,566,864**	**87,893,846**
Total liabilities and equity		**217,866,360**	**194,515,630**
Regulatory balances	10	12,239,024	13,385,770
Total liabilities, equity and regulatory balances		**$ 230,105,384**	**$ 207,901,400**

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, 2016, with comparative information for 2015

	Note	2016	2015
Revenue			
Distribution revenue		$ 25,938,435	$ 26,499,121
Other	15	2,210,670	2,321,993
		28,149,105	28,821,114
Sale of energy		165,669,063	150,854,522
Total revenue		193,818,168	179,675,636
Operating expenses			
Distribution and maintenance		6,494,744	6,532,204
Utilization		219,410	247,828
Billing and collecting expenses		5,340,057	5,306,947
Administration and general		5,204,616	4,780,394
Depreciation and amortization		6,462,385	6,099,694
Depreciation expense on fair value bump in amalgamation		1,084,545	1,088,859
	16	24,805,757	24,055,926
Cost of power purchased		164,516,077	146,612,973
Total expenses		189,321,834	170,668,899
Income from operating activities		**4,496,334**	**9,006,737**
Finance income	17	108,114	105,631
Finance costs	17	(2,427,543)	(2,524,270)
Income before income taxes		**2,176,905**	**6,588,098**
Income tax expense	9	(238,033)	(1,190,377)
Net income for the year		**1,938,872**	**5,397,721**
Net movement in regulatory balances, net of tax			
Net movement in regulatory balances	10	1,517,897	(602,491)
Income tax		616,249	(557,903)
		2,134,146	(1,160,394)
Net income for the year, net movement in regulatory balances and comprehensive income		**4,073,018**	**4,237,327**
Other comprehensive income			
Items that will not be reclassified to profit or loss:			
Remeasurements of post-employment benefits	13	0	817,041
Net movement in regulatory balances, net of tax	10	0	(817,041)
Other comprehensive income for the year		0	0
Total comprehensive income for the year		**$ 4,073,018**	**$ 4,237,327**

See accompanying notes to the financial statements.

NIAGARA PENINSULA ENERGY INC.

Statement of Changes in Equity
Year ended December 31, 2016, with comparative information for 2015

	Share capital	Contributed surplus	Retained earnings	Total
Balance at January 1, 2015	$ 31,245,882	$ 25,459,207	$ 28,151,430	$ 84,856,519
Net Income, net movement in regulatory balances and comprehensive income	0	0	4,237,327	4,237,327
Dividends	0	0	(1,200,000)	(1,200,000)
Balance at December 31, 2015	**$ 31,245,882**	**$ 25,459,207**	**$ 31,188,757**	**$ 87,893,846**
Balance at January 1, 2016	$ 31,245,882	$ 25,459,207	$ 31,188,757	$ 87,893,846
Net income, net movement in regulatory balances and comprehensive income	0	0	4,073,018	4,073,018
Dividends	0	0	(1,400,000)	(1,400,000)
Balance at December 31, 2016	**$ 31,245,882**	**$ 25,459,207**	**$ 33,861,775**	**$ 90,566,864**

See accompanying notes to the financial statements.

NIAGARA PENINSULA ENERGY INC.

Statement of Cash Flows
Year ended December 31, 2016, with comparative information for 2015

	2016	2015
Operating activities		
Net Income and net movement in regulatory balances	$ 4,073,018	$ 4,237,327
Adjustments for:		
Depreciation and amortization	6,232,159	5,833,962
Depreciation and amortization intangible assets	230,226	265,732
Depreciation fair value bump in amalgamation	1,084,545	1,088,858
Amortization of capital contributions	(738,438)	(613,262)
Contributions received from customers	4,031,451	5,600,233
Net loss on disposal of property, plant and equipment	8,384	0
Post-employment benefits	115,148	101,919
Interest expense	2,319,429	2,418,640
Employees' accumulated vested sick leave	2,954	2,093
Deferred tax expense	426,904	331,194
Current tax expense	(188,871)	859,183
	17,596,909	20,125,879
Change in non-cash operating working capital:		
Accounts receivable	(97,877)	(1,119,111)
Due to/from related parties	(13,337)	(10,369)
Unbilled revenue	162,777	(920,854)
Materials and supplies	134,073	(17,933)
Prepaid expenses	1,082	(344,251)
Accounts payable and accrued liabilities	(1,198,581)	(708,301)
Customer deposits	9,757	38,565
Deferred revenue	(116,726)	374,116
	16,478,077	17,417,741
Regulatory balances	(2,134,146)	1,160,394
Income tax paid	(1,291,186)	(103,531)
Income tax received	28,364	0
Interest paid	(2,427,543)	(2,524,270)
Interest received	108,114	105,631
Net cash from operating activities	**10,761,680**	**16,055,965**
Investing activities		
Purchase of property, plant and equipment	(15,083,955)	(14,838,726)
Purchase of intangible assets	(342,477)	(183,005)
Net cash used by investing activities	**(15,426,432)**	**(15,021,731)**
Financing activities		
Dividends paid	(1,400,000)	(1,200,000)
Proceeds from long-term debt	20,000,000	2,250,000
Repayment of long-term debt	(1,420,498)	(3,627,575)
Net cash from financing activities	**17,179,502**	**(2,577,575)**
Change in cash and cash equivalents	12,514,750	(1,543,341)
Cash and cash equivalents, beginning of year	9,048,994	10,592,335
Cash and cash equivalents, end of year	**$ 21,563,744**	**$ 9,048,994**

See accompanying notes to the financial statements.

NIAGARA PENINSULA ENERGY INC.

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, 2016.

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 18, 2017.

(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.

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 7,8 – estimation of useful lives of its property, plant and equipment and intangible assets
(iii) Note 10 – recognition and measurement of regulatory balances
(iv) Note 13 – measurement of defined benefit obligations: key actuarial assumptions
(v) Note 18 – 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 certain customers for the debt retirement charge set by 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, 2016

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 2016 is 1.6%, 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 1.3%, to the previous year's rates.

NIAGARA PENINSULA ENERGY INC.

2. Basis of presentation (continued)

(f) Rate regulation (continued)

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 are classified as loans and receivables and all financial liabilities are classified as other liabilities. These financial instruments 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

Revenue from the sale and distribution of electricity is recognized as the electricity is delivered to customers on the basis of cyclical meter readings and estimated customer usage since the last meter reading date to the end of the year. 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, 2016

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.

Certain customers and developers are required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. 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.

(d) Property, plant and equipment

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.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2016

3. Significant accounting policies (continued)

(d) Property, plant and equipment (continued)

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.

The estimated useful lives are as follows:

	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

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2016

3. Significant accounting policies (continued)

(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:

	Years
Computer software	3 years
Land rights	25 years

(f) Impairment

(i) Financial assets measured at amortized cost

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss is calculated as the difference between an asset's carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate. Interest on the impaired assets continues to be recognized through the unwinding of the discount. Losses are recognized in profit or loss. An impairment loss is reversed through profit or loss if the reversal can be related objectively to an event occurring after the impairment loss was recognized.

(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.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2016

3. Significant accounting policies (continued)

(f) Impairment (continued)

(ii) Non-financial assets (continued)

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.

(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.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2016

3. Significant accounting policies (continued)

(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.

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.

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. 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.

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.

Revenue Recognition

The IASB has issued IFRS 15, Revenue from Contracts with Customers (“IFRS 15”). IFRS 15 replaces IAS 11 Construction Contracts, IAS 18 Revenue and various interpretations and establishes principles regarding the nature, amount, timing and uncertainty of revenue arising from contracts with customers. The standard requires entities to recognize revenue for the transfer of goods or services to customers measured at the amounts an entity expects to be entitled to in exchange for those goods or services. IFRS 15 is effective for annual periods beginning on or after January 1, 2018. The Corporation is assessing the impact of IFRS 15 on its results of operations, financial position and disclosures.

Financial Instruments

In July 2014, the IASB issued a new standard, IFRS 9 *Financial Instruments*, which will replace IAS 39 Financial Instruments: Recognition and Measurement. IFRS 9 is effective for annual periods beginning on or after January 1, 2018 and must be applied retrospectively. The Corporation is assessing the impact of IFRS 9 on its results of operations, financial position, and disclosures.

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 has determined that there will be no impact on the reporting of the Corporation.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2016

5. Accounts receivable

	2016	2015
Trade receivables	$ 13,469,077	$ 11,440,844
Other trade receivables	0	877,929
Billable work	1,556,981	2,692,431
City of Niagara Falls	203,504	83,430
Township of West Lincoln	10,209	0
Town of Pelham	8,971	7,390
Allowance for doubtful accounts	(544,268)	(495,427)
	$ 14,704,474	$ 14,606,597

6. Materials and supplies

No amount of inventory has been written down due to obsolescence (2015 - $0).

7. Property, plant and equipment

	Land and buildings	Distribution equipment	Total
Cost or deemed cost			
Balance at January 1, 2016	$ 16,476,747	$ 152,784,881	$ 169,261,628
Additions	52,753	15,031,202	15,083,955
Disposals/retirements	0	(733,860)	(733,860)
Balance at December 31, 2016	$ 16,529,500	$ 167,082,223	$ 183,611,723
Balance at January 1, 2015	$ 16,008,087	$ 139,109,880	$ 155,117,967
Additions	468,660	14,370,066	14,838,726
Disposals/retirements	0	(695,065)	(695,065)
Balance at December 31, 2015	$ 16,476,747	$ 152,784,881	$ 169,261,628
Accumulated depreciation			
Balance at January 1, 2016	$ 548,324	$ 12,132,773	$ 12,681,097
Depreciation	357,589	6,959,115	7,316,704
Disposals/retirements	0	(725,476)	(725,476)
Balance at December 31, 2016	$ 905,913	$ 18,366,412	$ 19,272,325
Balance at January 1, 2015	$ 261,628	$ 6,191,714	$ 6,453,342
Depreciation	286,696	6,636,124	6,922,820
Disposals/retirements	0	(695,065)	(695,065)
Balance at December 31, 2015	$ 548,324	$ 12,132,773	$ 12,681,097
Carrying amounts			
At December 31, 2016	$ 15,623,587	$ 148,715,811	$ 164,339,398
At December 31, 2015	15,928,423	140,652,108	156,580,531

At December 31, 2016 the assets of the company 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, 2016.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2016

8. Intangible assets

	Computer software	Land rights	Total
Cost or deemed cost			
Balance at January 1, 2016	$ 969,554	$ 132,776	$ 1,102,330
Additions	342,477	0	342,477
Balance at December 31, 2016	$ 1,312,031	$ 132,776	$ 1,444,807
Balance at January 1, 2015	$ 786,549	$ 132,776	$ 919,325
Additions	183,005	0	183,005
Balance at December 31, 2015	$ 969,554	$ 132,776	$ 1,102,330
Accumulated amortization			
Balance at January 1, 2016	$ 624,729	$ 132,776	$ 757,505
Amortization	230,226	0	230,226
Balance at December 31, 2016	$ 854,955	$ 132,776	$ 987,731
Balance at January 1, 2015	$ 425,385	$ 66,388	$ 491,773
Amortization	199,344	66,388	265,732
Balance at December 31, 2015	$ 624,729	$ 132,776	$ 757,505
Carrying amounts			
At December 31, 2016	$ 457,076	$ 0	$ 457,076
At December 31, 2015	344,825	0	344,825

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2016

9. Income tax

Current tax expense

	2016	2015
Current year	$ (80,990)	$ 859,183
Adjustment for prior years	(107,881)	0
	$ (188,871)	$ 859,183

Deferred tax expense

	2016	2015
Origination and reversal of temporary differences	$ 426,904	$ 331,194
	$ 426,904	$ 331,194

Reconciliation of effective tax rate

	2016	2015
Income before taxes	$ 2,176,905	$ 6,588,098
Canada and Ontario statutory Income tax rates	26.5%	26.50%
Expected tax provision on income at statutory rates	576,880	1,745,846
Increase (decrease) in income taxes resulting from:		
Permanent differences	7,392	6,757
Changes and differences in deferred tax rate	0	0
Corporate minimum tax and investment tax credits	(207,642)	(154,553)
Other	(138,587)	(407,673)
Income tax expense	$ 238,033	$ 1,190,377

Significant components of the Corporation's deferred tax balances

	2016	2015
Deferred tax assets (liabilities):		
Property, plant and equipment	$ (2,812,319)	$ (2,201,182)
Cumulative eligible capital	77,222	82,337
Post-employment benefits	694,101	663,587
Timing difference on regulatory assets and liabilities	1,973,402	1,959,431
Other reserves	120,112	(24,751)
	$ 52,518	$ 479,422

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2016

10. Regulatory balances

Reconciliation of the carrying amount for each class of regulatory balances

Regulatory deferral account debit balances	January 1, 2016	Additions	Recovery/ reversal	December 31, 2016	Remaining recovery/ reversal years
Group 1 deferred accounts	$ 1,869,860	$ 823,588	$ 0	$ 2,693,448	2.33
Regulatory settlement account	1,129,876	3,372	(810,208)	323,040	2.33
Other regulatory accounts	657,401	166,288	(34,077)	789,612	4.00
Income tax	2,882,781	838,437	0	3,721,218	4.00
	$ 6,539,918	$ 1,831,685	$ (844,285)	$ 7,527,318	

Regulatory deferral account debit balances	January 1, 2015	Additions	Recovery/ reversal	December 31, 2015	Remaining recovery/ reversal years
Group 1 deferred accounts	$ 5,734,737	$ (3,663,741)	$ (201,136)	$ 1,869,860	2.33
Regulatory settlement account	0	1,782,460	(652,584)	1,129,876	2.33
Other regulatory accounts	1,720,301	518,424	(1,581,324)	657,401	5.00
Income tax	2,986,690	(103,909)	0	2,882,781	5.00
	$ 10,441,728	$ (1,466,766)	$ (2,435,044)	$ 6,539,918	

Regulatory deferral account credit balances	January 1, 2016	Additions	Recovery/ reversal	December 31, 2016	Remaining years
Group 1 deferred accounts	$ (6,008,409)	$(2,412,250)	$ 374,186	$(8,046,473)	2.33
Regulatory settlement account	(4,998,884)	(255,811)	3,702,606	(1,552,089)	2.33
Other regulatory accounts	(1,614,542)	(39,797)	0	(1,654,339)	4.00
Income tax	(763,935)	(222,188)	0	(986,123)	0
	$ (13,385,770)	$(2,930,046)	$ 4,076,792	$(12,239,024)	

Regulatory deferral account credit balances	January 1, 2015	Additions	Recovery/ reversal	December 31, 2015	Remaining years
Group 1 deferred accounts	$ (5,429,850)	$ (578,559)	$ 0	$ (6,008,409)	2.33
Regulatory settlement account	(1,224,136)	(6,910,688)	3,135,940	(4,998,884)	2.33
Other regulatory accounts	(7,740,517)	(43,921)	6,169,896	(1,614,542)	5.00
Income tax	(309,941)	(453,994)	0	(763,935)	0
	$ (14,704,444)	$ (7,987,162)	$ 9,305,836	$(13,385,770)	

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2016

10. 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, 2015. These balances were included in the Corporation's IRM application in 2016 for rates effective May 1, 2017. 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 20, 2018. 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 2016 the rate was 1.100% (2015 - 1.1925%).

11. Accounts payable and accrued liabilities

	2016	2015
Accounts payable – energy purchases	$ 16,561,845	$17,145,238
Debt retirement charge payable to OEFC	453,312	722,234
Payroll payable	1,079,891	1,129,867
Other	340,168	565,649
City of Niagara Falls	994	68,636
Town of Lincoln	0	3,435
Township of West Lincoln	1,095	827
	$ 18,437,305	$19,635,886

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2016

12. Long-term debt

	2016	2015
Secured bank loans	$ 42,975,217	$ 34,441,572
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
	$ 68,580,307	$ 60,046,662

The notes payable bear interest at 5.32% 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, 2017. 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:

	2016	2015
TD bank term loan-fixed rate 4.58% due July 2019. Repayment is in equal monthly installments of $93,442 of interest and principal	$ 2,754,072	$ 3,724,570
Scotiabank loan-fixed rate 2.67% due September 2020. Repayment is in equal monthly installments of $37,500 plus interest	1,687,500	2,137,500
TD loan-interest only-fixed rate 2.80% due June 2017	10,000,000	10,000,000
TD loan-interest only-fixed rate 2.933% due December 2018	10,000,000	10,000,000
TD loan-interest only-fixed rate 2.633% due November 2019	10,000,000	10,000,000
Meridian Credit Union loan-interest only-fixed rate 2.60% due September 2026	20,000,000	0
	$ 54,441,572	$ 35,862,070

Principal payments on the secured bank loans are as follows:

2017	$ 11,466,355
2018	11,544,261
2019	11,093,456
2020	337,500
2021	0
2022 – 2026	20,000,000
	54,441,572
Less: current portion	11,466,355
Long-term portion of loan	$ 42,975,217

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2016

13. 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 2016, the Corporation made employer contributions of $1,215,948 to OMERS (2015 - $1,133,347), of which $351,274 (2015 - $317,247) has been capitalized as part of PP&E and the remaining amount of $864,674 (2015 - $816,100) has been recognized in profit or loss. The Corporation estimates that a contribution of $1,240,267 to OMERS will be made during the next fiscal year.

As at December 31, 2016, OMERS had approximately 470,000 members, of whom 123 are current employees of the Corporation. The most recently available OMERS annual report is for the year ended December 31, 2016, which reported that the plan was 93.4% funded, with an unfunded liability of $5.7 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	2016	2015
Defined benefit obligation, beginning of year	$ 2,504,100	$ 2,402,181
Included in profit or loss		
Current service cost	104,425	99,642
Interest cost	117,631	112,655
	2,726,156	2,614,478
Benefits paid	(106,908)	(110,378)
Defined benefit obligation, end of year	$ 2,619,248	$ 2,504,100

Actuarial assumptions	2016	2015
General inflation	2.00%	2.00%
Discount (interest) rate	4.80%	4.80%
Salary levels	3.10%	3.10%
Medical Costs	6.40%	6.70%
Dental Costs	4.60%	4.60%

A 1% increase in the assumed discount rate would result in the defined benefit obligation decreasing to $2,322,000. A 1% decrease in the assumed discount rate would result in the defined benefits obligation increasing to $2,989,000.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2016

14. Share capital

	2016	2015
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 (2015 - $1,200), which amount to total dividends paid in the year of $1,400,000 (2015 - $1,200,000).

15. Other revenue

	2016	2015
Pole rental revenue	$ 242,690	$ 253,234
Interest charges on hydro sales	429,277	424,468
Collection & reconnection charges	270,121	281,667
Occupancy change charge	205,290	188,670
Miscellaneous service revenues	250,632	149,246
Miscellaneous non-operating revenue	98,693	103,532
Contributions received from customers	738,438	613,263
Government grants under CDM programs	533,044	114,410
Government grant expenditures under CDM programs	(533,044)	(114,410)
Performance incentive payments under CDM programs	(16,087)	278,313
Gain/(loss) on disposal of property, plant & equipment	(8,384)	29,600
	$ 2,210,670	$ 2,321,993

16. Operating expenses

	2016	2015
Salaries, wages and benefits	$ 9,774,533	$ 9,428,357
Materials and supplies	180,476	148,286
Vehicle expenditures	304,663	320,978
Outside purchases	6,780,803	6,684,636
Bad Debt expenses	218,352	285,116
Depreciation and amortization	7,546,930	7,188,553
	$ 24,805,757	$ 24,055,926

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2016

17. Finance income and costs

	2016	2015
Finance income		
Interest income on bank deposits	$ 108,114	$ 105,631
Finance costs		
Interest expense on long-term debt	1,195,429	1,138,961
Interest expense on debt to associated companies	1,221,363	1,362,191
Interest expense on customer deposits	10,494	14,667
Other	258	8,451
	2,427,544	2,524,270
Net finance costs recognized in profit or loss	$ 2,319,430	$ 2,418,639

18. 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 company has arranged for a standby letter of credit of $12,000,000 (2015 - $12,000,000) of which $11,910,187 (2015 - $11,910,187) has been drawn down. The Independent Electricity Market Operator is the beneficiary for $11,910,187 (2015 - $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, 2016, no assessments have been made.

19. 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, 2016

19. Related party transactions (continued)

(a) Outstanding balances with related parties included in Due from (to) related parties:

	2016	2015
Peninsula West Services Ltd.	$ 2,742	$ (7,355)
Niagara Falls Hydro Holding Corporation	1,620	0
Niagara Falls Hydro Services Inc.	1,620	0
	$ 5,982	$ (7,355)

These balances are non-interest bearing with no fixed repayment terms.

(b) Transactions with ultimate parent

	2016	2015
Revenue:		
Energy sales (at commercial rates)		
City of Niagara Falls	$ 2,774,125	$ 2,726,229
Town of Lincoln	425,707	431,727
Township of West Lincoln	234,305	242,905
Town of Pelham	55,862	50,173
	$ 3,489,999	$ 3,451,034

	2016	2015
Expenses:		
Property taxes		
City of Niagara Falls	$ 209,925	$ 165,288
Town of Lincoln	2,128	2,059
Township of West Lincoln	81,687	79,850
Town of Pelham	629	627
Water expenses		
City of Niagara Falls	11,282	12,340
Township of West Lincoln	4,224	4,200
Other miscellaneous expenses		
City of Niagara Falls	10,440	3,358
Township of West Lincoln	858	600
Town of Pelham	4,510	3,270
Town of Lincoln	7,200	0
	$ 332,883	$ 271,592

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2016

19. Related party transactions (continued)

(c) Transactions with parent

	2016	2015
Revenue:		
Accounting services		
Peninsula West Power Inc.	$ 1,000	$ 1,000

(d) Transaction with related party

	2016	2015
Revenue:		
Accounting services		
Peninsula West Services Ltd.	$ 14,657	$ 25,120

(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:

	2016	2015
Directors' fees	$ 74,650	$ 83,023
Salaries and other short-term benefits	1,425,419	1,339,853
	$ 1,500,069	$ 1,422,876

NIAGARA PENINSULA ENERGY INC.

20. Financial instruments and risk management

Fair value disclosure

The carrying values of cash and cash equivalents, accounts receivable, unbilled revenue, due from/to related parties 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, 2016 is $72,888,000 (2015 - $58,370,000). 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, 2016 was 3.61% (2015 - 3.94%).

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, 2016 is $544,268 (2015 - $495,427). An impairment loss of $218,352 (2015 - $285,115) 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, 2016, approximately $661,348 (2015 - $560,261) is considered 60 days past due. The Corporation has over 52,000 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, 2016, the Corporation holds security deposits in the amount of $1,505,461 (2015 - $1,495,704).

20. 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, 2016, 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 (2015 - $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, 2016, shareholder's equity amounts to $90,566,864 (2015 - $87,893,846) and long-term debt amounts to $68,580,307 (2015 - $60,046,662).

Financial Statements of

Niagara Peninsula Energy Inc.

Year ended December 31, 2015

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INDEPENDENT AUDITORS' REPORT

To the Board Members and Shareholders of Niagara Peninsula Energy Inc.:

We have audited the accompanying financial statements of Niagara Peninsula Energy Inc. ("the entity"), which comprise the statements of financial position as at December 31, 2015, December 31, 2014 and January 1, 2014, the statements of comprehensive income, changes in equity and cash flows for the years ended December 31, 2015, and December 31, 2014, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, 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.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audits to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the Entity's preparation and fair presentation of the financial statements 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. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Niagara Peninsula Energy Inc. as at December 31, 2015, December 31, 2014 and January 1, 2014, and its financial performance and its cash flows for the years ended December 31, 2015, and December 31, 2014 in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

April 18, 2016

St. Catharines, Canada

NIAGARA PENINSULA ENERGY INC.

Statements of Financial Position
Year ended December 31, 2015, with comparative information for 2014

	Note	December 31, 2015	December 31, 2014	January 1, 2014
Assets				
Current assets				
Cash and cash equivalents		$ 9,048,994	$ 10,592,335	$ 11,481,267
Accounts receivable	5	14,606,597	13,487,486	11,083,678
Due from related parties	19	0	5,851	2,100
Unbilled revenue		17,383,378	16,462,524	16,837,560
Income taxes receivable		306,277	1,061,929	1,520,859
Materials and supplies	6	1,498,947	1,481,014	1,621,583
Prepaid expenses		1,112,511	768,260	829,213
Total current assets		43,956,704	43,859,399	43,376,260
Non-current assets				
Property, plant and equipment	7	156,580,531	148,664,625	140,574,794
Intangible assets	8	344,825	427,552	381,723
Total non-current assets		156,925,356	149,092,177	140,956,517
Total assets		200,882,060	192,951,576	184,332,777
Regulatory balances	10	11,854,596	13,529,967	15,353,096
Total assets and regulatory balances		$ 212,736,656	$ 206,481,543	$ 199,685,873

NIAGARA PENINSULA ENERGY INC.

Statements of Financial Position
Year ended December 31, 2015, with comparative information for 2014

	Note	December 31, 2015	December 31, 2014	January 1, 2014
Liabilities				
Current liabilities				
Accounts payable and accrued liabilities	11	$ 19,635,886	$ 20,344,185	$ 14,739,090
Due to related parties	19	7,355	23,575	6,913,022
Long-term debt due within one year	12	1,420,498	3,515,075	1,869,628
Customer deposits		1,533,038	1,494,473	1,456,011
Deferred revenue		830,673	456,557	1,299,695
Total current liabilities		23,427,450	25,833,865	26,277,446
Non-current liabilities				
Long-term debt	12	60,046,662	59,329,660	52,844,734
Employees' vested sick leave		52,228	50,135	112,861
Post-employment benefits	13	2,504,100	2,402,181	2,315,668
Deferred capital contributions		20,591,344	15,604,373	14,891,276
Deferred tax liabilities	9	1,480,009	612,127	246,001
Total non-current liabilities		84,674,343	77,998,476	70,410,540
Total liabilities		108,101,793	103,832,341	96,687,986
Equity				
Share capital	14	31,245,882	31,245,882	31,245,882
Contributed surplus		25,459,207	25,459,207	25,459,207
Retained earnings		31,188,757	28,151,430	27,031,859
Total equity		87,893,846	84,856,519	83,736,948
Total liabilities and equity		195,995,639	188,688,860	180,424,934
Regulatory balances	10	16,741,017	17,792,683	19,260,939
Total liabilities, equity and regulatory balances		$ 212,736,656	$ 206,481,543	$ 199,685,873

See accompanying notes to the financial statements.

On behalf of the Board:

Bruce Walker Director

Director

NIAGARA PENINSULA ENERGY INC.

Statements of Comprehensive Income
Year ended December 31, 2015, with comparative information for 2014

	Note	2015	2014
Revenue			
Sale of energy		$ 150,854,522	$ 136,846,497
Distribution revenue		26,499,121	25,650,225
Other	15	2,321,993	2,098,546
		179,675,636	164,595,268
Cost of power			
Cost of power purchased		146,612,973	136,981,847
		33,062,663	27,613,421
Operating expenses			
Distribution and maintenance	16	6,532,204	6,520,031
Utilization	16	247,828	205,566
Billing and collecting expenses	16	5,306,947	4,875,752
Administration and general	16	4,780,394	4,495,888
Depreciation and amortization	16	6,099,694	6,193,862
Depreciation expense on fair value bump in amalgamation	16	1,088,859	1,099,638
		24,055,926	23,390,737
Income from operating activities		9,006,737	4,222,684
Finance income	17	105,631	116,333
Finance costs	17	(2,524,270)	(2,355,522)
Income before income taxes		6,588,098	1,983,495
Income tax expense	9	(1,727,064)	(938,993)
Net income for the year		4,861,034	1,044,502
Net movement in regulatory balances, net of tax	10	(623,707)	1,275,069
Net income for the year, net movement in regulatory balances and comprehensive income		4,237,327	2,319,571
Other comprehensive income			
Items that will not be reclassified to profit or loss:			
Remeasurements of post-employment benefits	13	817,041	0
Net movement in regulatory balances, net of tax	10	(817,041)	0
Other comprehensive income for the year		0	0
Total comprehensive income for the year		$ 4,237,327	$ 2,319,571

See accompanying notes to the financial statements.

NIAGARA PENINSULA ENERGY INC.

Statements of Changes in Equity
Year ended December 31, 2015, with comparative information for 2014

	Share capital	Contributed surplus	Retained earnings	Total
Balance at January 1, 2014	$ 31,245,882	$ 25,459,207	$ 27,031,859	$ 83,736,948
Net Income, net movement in regulatory balances and comprehensive income	0	0	2,319,571	2,319,571
Dividends	0	0	(1,200,000)	(1,200,000)
Balance at December 31, 2014	$ 31,245,882	$ 25,459,207	$ 28,151,430	$ 84,856,519
Balance at January 1, 2015	$ 31,245,882	$ 25,459,207	$ 28,151,430	$ 84,856,519
Net income, net movement in regulatory balances and comprehensive income	0	0	4,237,327	4,237,327
Dividends	0	0	(1,200,000)	(1,200,000)
Balance at December 31, 2015	$ 31,245,882	$ 25,459,207	$ 31,188,757	$ 87,893,846

See accompanying notes to the financial statements.

NIAGARA PENINSULA ENERGY INC.

Statements of Cash Flows
Year ended December 31, 2015, with comparative information for 2014

	2015	2014
Operating activities		
Net Income and net movement in regulatory balances	$ 4,237,327	$ 2,319,571
Adjustments for:		
Depreciation and amortization	5,833,962	5,702,089
Depreciation and amortization intangible assets	265,732	491,773
Depreciation fair value bump in amalgamation	1,088,858	1,099,638
Amortization of deferred revenue	(613,262)	(514,542)
Post-employment benefits	101,919	86,513
Interest expense	2,418,640	2,239,189
Employees' accumulated vested sick leave	2,093	(62,726)
Deferred tax expense	867,881	366,126
Current tax expense	859,183	572,867
	15,062,333	12,300,498
Change in non-cash operating working capital:		
Accounts receivable	(1,119,111)	(2,403,808)
Due to/from related parties	(10,369)	(6,893,198)
Unbilled revenue	(920,854)	375,036
Materials and supplies	(17,933)	140,569
Prepaid expenses	(344,251)	60,953
Income tax receivable	(103,531)	(113,937)
Accounts payable and accrued liabilities	(708,301)	5,605,096
Customer deposits	38,565	38,462
Deferred revenue	374,116	(843,138)
	(2,811,669)	(4,033,965)
Regulatory balances	623,707	(1,275,069)
Interest paid	(2,524,270)	(2,355,522)
Interest received	105,631	116,333
Net cash from operating activities	10,455,732	4,752,275
Investing activities		
Purchase of property, plant and equipment	(14,838,726)	(13,293,343)
Purchase of intangible assets	(183,005)	(537,602)
Contributions received from customers	5,600,233	1,259,365
Net cash used by investing activities	(9,421,498)	(12,571,580)
Financing activities		
Dividends paid	(1,200,000)	(1,200,000)
Proceeds from long-term debt	2,250,000	10,000,000
Repayment of long-term debt	(3,627,575)	(1,869,627)
Net cash from financing activities	(2,577,575)	6,930,373
Change in cash and cash equivalents	(1,543,341)	(888,932)
Cash and cash equivalents, beginning of year	10,592,335	11,481,267
Cash and cash equivalents, end of year	$ 9,048,994	$ 10,592,335

See accompanying notes to the financial statements.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2015

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, 2015.

2. Basis of presentation

(a) Statement of compliance

The Corporation's financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS").

(b) Adoption of IFRS

These are the Corporation’s first financial statements prepared in accordance with IFRS and IFRS 1 *First-time Adoption of International Financial Reporting Standards* has been applied. An explanation of how the transition to IFRS has affected the reported financial position, financial performance and cash flows of the Corporation is provided in note 21.

The financial statements were approved by the Board of Directors on April 18, 2016.

(c) Basis of measurement

These financial statements have been prepared on the historical cost basis, unless otherwise stated.

(d) Functional and presentation currency

These financial statements are presented in Canadian dollars, which is the Corporation's functional currency. All financial information presented in Canadian dollars.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2015

2. Basis of presentation (continued)

(e) 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 7,8 – estimation of useful lives of its property, plant and equipment and intangible assets
(iii) Note 10 – recognition and measurement of regulatory balances
(iv) Note 13 – measurement of defined benefit obligations: key actuarial assumptions
(v) Note 18 – recognition and measurement of provisions and contingencies

(f) 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. The Corporation may file to recover uncollected debt retirement charges from Ontario Electricity Financial Corporation (“OEFC”) once each year.

2. Basis of presentation (continued)

(f) Rate regulation (continued)

Rate setting

Distribution revenue

For the distribution revenue included in sale of energy, the Corporation files a "Cost of Service" ("COS") rate application with the OEB every five years where 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 new 2015 rates were implemented and effective as of June 1, 2015 and remain interim, 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 GDP IPI-FDD for 2016 is 1.6%, the Corporation's productivity factor is 0% and the stretch factor is 0.3%, resulting in a net adjustment of 1.3% 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.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2015

3. Significant accounting policies

The accounting policies set out below have been applied consistently in all years presented in these financial statements and in preparing the opening IFRS statement of financial position at January 1, 2014 for the purpose of the transition to IFRS.

(a) Financial instruments

All financial assets are classified as loans and receivables and all financial liabilities are classified as other liabilities. These financial instruments 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.

Cash equivalents include short-term investments with maturities of three months or less when purchased.

(b) Revenue recognition

Sale and distribution of electricity

Revenue from the sale and distribution of electricity is recognized as the electricity is delivered to customers on the basis of cyclical meter readings and estimated customer usage since the last meter reading date to the end of the year. 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.

Other revenue

Revenue earned from the provision of services is recognized as the service is rendered or contract milestones are achieved. Amounts received in advance of these milestones are presented as deferred revenue.

Certain customers and developers are required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. 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.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2015

3. Significant accounting policies (continued)

(b) Revenue recognition (continued)

Government grants and the related performance incentive payments under 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 is 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.

(d) Property, plant and equipment

Items of property, plant and equipment ("PP&E") used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost established on the transition date (see note 21(a)), less accumulated depreciation. All other items of PP&E 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.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2015

3. Significant accounting policies (continued)

(d) Property, plant and equipment (continued)

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.

The estimated useful lives are as follows:

	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 transition date (see note 21a), less accumulated amortization. All other intangible assets are measured at cost.

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:

	Years
Computer software	3 years
Land rights	25 years

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2015

3. Significant accounting policies (continued)

(f) Impairment

(i) Financial assets measured at amortized cost

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss is calculated as the difference between an asset's carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate. Interest on the impaired assets continues to be recognized through the unwinding of the discount. Losses are recognized in profit or loss. An impairment loss is reversed through profit or loss if the reversal can be related objectively to an event occurring after the impairment loss was recognized.

(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.

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.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2015

3. Significant accounting policies (continued)

(i) Regulatory balances (continued)

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.

(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. Remeasurements 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.

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 and cash equivalents.

Finance costs comprise interest expense on borrowings, and interest paid on 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.

4. Standards issued but not yet adopted

Future accounting changes

There are new standards, amendments to standards and interpretations which have not been applied in preparing these financial statements. The Corporation is still evaluating the adoption of the following new and revised standards along with any subsequent amendments.

Revenue Recognition

In July 2015, the IASB announced a one-year deferral of the Revenue from Contracts with Customers ("IFRS 15") effective date. IFRS 15 replaces IAS 11 Construction Contracts, IAS 18 Revenue and various interpretations and establishes principles regarding the nature, amount, timing and uncertainty of revenue arising from contracts with customers. The standard requires entities to recognize revenue for the transfer of goods or services to customers measured at the amounts an entity expects to be entitled to in exchange for those goods or services. IFRS 15 is effective for annual periods beginning on or after January 1, 2018. The Corporation is assessing the impact of IFRS 15 on its results of operations, financial position, and disclosures.

Financial Instruments

In July 2014, the IASB issued a new standard, IFRS 9 *Financial Instruments*, which will replace IAS 39 Financial Instruments: Recognition and Measurement. The replacement of IAS 39 is a multi-phase project with the objective of improving and simplifying the reporting for financial instruments. The issuance of IFRS 9 is part of the first phase of this project. IFRS 9 is effective for annual periods beginning on or after January 1, 2018 and must be applied retrospectively. The Corporation is assessing the impact of IFRS 9 on its results of operations, financial position, and disclosures.

Property, Plant, and Equipment and Intangible Assets

In May 2014, the IASB issued amendments to IAS 16, *Property, Plant and Equipment* and IAS 38 *Intangible Assets,* which are effective for years beginning on or after January 1, 2016. The amendments clarify when revenue-based depreciation methods are permitted. The Corporation is assessing the impact of the amendments on its results of operations, financial positions, and disclosures.

Leases

In January 2016, IASB issued IFRS 16 to establish principles for the recognition, measurement, presentation and disclosure of leases, with the objective of ensuring that lessees and lessors provide relevant information that faithfully represents those transactions. IFRS 16 replaces IAS 17 and it is effective for annual periods beginning on or after January 1, 2019. The Corporation is assessing the impact of IFRS 16 on its results of operations, financial positions, and disclosures.

All of the above standards or amendments relate to the measurement and disclosure of assets and liabilities. The extent of the impact on adoption of these standards and amendments has not yet been determined.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2015

5. Accounts receivable

	December 31, 2015	December 31, 2014	January 1, 2014
Trade receivables	$ 11,440,844	$ 11,378,234	$ 9,664,415
Other trade receivables	877,929	350,297	229,541
Billable work	2,692,431	1,969,375	1,464,465
City of Niagara Falls	83,430	258,591	201,004
Town of Lincoln	0	218	0
Township of West Lincoln	0	21,222	20,889
Town of Pelham	7,390	5,780	7,841
Allowance for doubtful accounts	(495,427)	(496,231)	(504,477)
	$ 14,606,597	$ 13,487,486	$ 11,083,678

6. Materials and supplies

Amount written down due to obsolescence in 2015 was $0 (2014 - $0).

7. Property, plant and equipment

	Land and buildings	Distribution equipment	Total
Cost or deemed cost			
Balance at January 1, 2015	$ 16,008,087	$ 139,109,880	$ 155,117,967
Additions	468,660	14,370,066	14,838,726
Disposals/retirements	0	(695,065)	(695,065)
Balance at December 31, 2015	$ 16,476,747	$ 152,784,881	$ 169,261,628
Balance at January 1, 2014	$ 14,395,014	$ 126,179,780	$ 140,574,794
Additions	1,613,073	13,583,358	15,196,431
Disposals/retirements	0	(653,258)	(653,258)
Balance at December 31, 2014	$ 16,008,087	$ 139,109,880	$ 155,117,967
Accumulated depreciation			
Balance at January 1, 2015	$ 261,628	$ 6,191,714	$ 6,453,342
Depreciation	286,696	6,636,124	6,922,820
Disposals/retirements	0	(695,065)	(695,065)
Balance at December 31, 2015	$ 548,324	$ 12,132,773	$ 12,681,097
Balance at January 1, 2014	$ 0	$ 0	$ 0
Depreciation	261,628	6,844,972	7,106,600
Disposals/retirements	0	(653,258)	(653,258)
Balance at December 31, 2014	$ 261,628	$ 6,191,714	$ 6,453,342
Carrying amounts			
At December 31, 2015	$ 15,928,423	$ 140,652,108	$ 156,580,531
At December 31, 2014	15,746,459	132,918,166	148,664,625
At January 1, 2014	14,395,014	126,179,780	140,574,794

At December 31, 2015 land and buildings with a carrying amount of $15,928,423 (2014 - $15,746,459) are subject to a general security agreement.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2015

7. Property, plant and equipment (continued)

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, 2015.

8. Intangible assets

	Computer software	Land rights	Total
Cost or deemed cost			
Balance at January 1, 2015	$ 786,549	$ 132,776	$ 919,325
Additions	183,005	0	183,005
Balance at December 31, 2015	$ 969,554	$ 132,776	$ 1,102,330
Balance at January 1, 2014	$ 248,947	$ 132,776	$ 381,723
Additions	537,602	0	537,602
Balance at December 31, 2014	$ 786,549	$ 132,776	$ 919,325
Accumulated amortization			
Balance at January 1, 2015	$ 425,385	$ 66,388	$ 491,773
Amortization	199,344	66,388	265,732
Balance at December 31, 2015	$ 624,729	$ 132,776	$ 757,505
Balance at January 1, 2014	$ 0	$ 0	$ 0
Amortization	425,385	66,388	491,773
Balance at December 31, 2014	$ 425,385	$ 66,388	$ 491,773
Carrying amounts			
At December 31, 2015	$ 344,825	$ 0	$ 344,825
At December 31, 2014	361,164	66,388	427,552
At January 1, 2014	248,947	132,776	381,723

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2015

9. Income tax expense

Current tax expense

	2015	2014
Current year	$ 859,183	$ 572,867
Adjustment for prior years	0	0
	$ 859,183	$ 572,867

Deferred tax expense

	2015	2014
Origination and reversal of temporary differences	$ 867,881	$ 366,126
	$ 867,881	$ 366,126

Reconciliation of effective tax rate

	2015	2014
Income before taxes	$6,588,098	$ 1,983,495
Canada and Ontario statutory Income tax rates	26.50%	26.50%
Expected tax provision on income at statutory rates	1,745,846	525,626
Increase (decrease) in income taxes resulting from:		
Permanent differences	6,757	0
Changes and differences in deferred tax rate	0	0
Corporate minimum tax and investment tax credits	(154,553)	(28,029)
Other	129,014	441,396
Income tax expense	$ 1,727,064	$ 938,993

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2015

9. Income tax expense

(a) Income tax expense (continued)

Significant components of the Corporation's deferred tax balances

	2015	2014	January 1, 2014
Deferred tax assets (liabilities):			
Property, plant and equipment	$(2,201,182)	$(1,339,993)	$ (950,561)
Cumulative eligible capital	82,337	85,988	90,907
Post-employment benefits	663,587	641,878	613,653
Other reserves	(24,751)	0	0
	$(1,480,009)	$ (612,127)	$ 246,001

10. Regulatory balances

Reconciliation of the carrying amount for each class of regulatory balances

Regulatory deferral account debit balances	January 1, 2015	Additions	Recovery/ reversal	December 31, 2015	Remaining recovery/ reversal years
Group 1 deferred accounts	$ 8,680,793	$ (3,396,733)	$ (201,136)	$ 5,082,924	2.33
Regulatory settlement account	0	1,782,460	(652,584)	1,129,876	1.33
Other regulatory accounts	1,720,301	518,424	(1,581,324)	657,401	5.00
Income tax	3,128,873	1,855,522	0	4,984,395	5.00
	$ 13,529,967	$ 759,673	$ (2,435,044)	$11,854,596	

Regulatory deferral account debit balances	January 1, 2014	Additions	Recovery/ reversal	December 31, 2014	Remaining years
Group 1 deferred accounts	$ 10,817,891	$ 4,593,970	$ (6,731,068)	$ 8,680,793	3.33
Other regulatory accounts	2,455,170	76,741	(811,610)	1,720,301	6.00
Income tax	2,080,035	1,048,839	0	3,128,873	6.00
	$ 15,353,096	$ 5,719,550	$ (7,542,678)	$13,529,967	

Regulatory deferral account credit balances	January 1, 2015	Additions	Recovery/ reversal	December 31, 2015	Remaining years
Group 1 deferred accounts	$ (8,375,906)	$ (845,567)	$ 0	$ (9,221,473)	2.33
Regulatory settlement account	(1,224,136)	(6,910,688)	3,135,940	(4,998,884)	1.33
Other regulatory accounts	(7,740,517)	(43,921)	6,169,896	(1,614,542)	1.33
Income tax	(452,124)	(453,994)	0	(906,118)	0
	$ (17,792,683)	$ (8,254,170)	$ 9,305,836	$(16,741,017)	

Regulatory deferral account credit balances	January 1, 2014	Additions	Recovery/ reversal	December 31, 2014	Remaining years
Group 1 deferred accounts	$ (13,556,411)	$ (4,206,771)	$ 9,387,276	$ (8,375,906)	3.33
Regulatory settlement account	(769,398)	(17,401)	(437,337)	(1,224,136)	2.33
Other regulatory accounts	(4,625,187)	(3,115,330)	0	(7,740,517)	2.33
Income tax	(309,943)	(142,181)	0	(452,124)	0
	$ (19,260,939)	$ (7,481,683)	$ 8,949,939	$(17,792,683)	

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2015

10. 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 recover the Group 1 deferral accounts as at December 31, 2014. However these balances were below the threshold test for disposal of Group 1 deferral accounts. These balances will remain until the Corporation files its next application in 2016 for rates effective May 1, 2017. Once approval is received, the approved account balance is moved to the regulatory settlement account. Approval has been received from the OEB to recover/repay the regulatory settlement account balance. The balance is to be recovered/repaid was over a period of 2 year ending April 20, 2017. 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 2015 the rate was 1.1925%.

11. Accounts payable and accrued liabilities

	2015	2014	January 1, 2014
Accounts payable – energy purchases	$ 17,145,238	$ 18,118,223	$12,567,286
Debt retirement charge payable to OEFC	722,234	759,130	781,312
Payroll payable	1,129,867	993,559	894,204
Other	565,649	448,762	495,229
City of Niagara Falls	68,636	4,684	0
Town of Lincoln	3,435	18,984	305
Township of West Lincoln	827	843	754
	$ 19,635,886	$ 20,344,185	$14,739,090

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2015

12. Long-term debt

	2015	2014	January 1, 2014
Secured bank loans	$ 34,441,572	$ 33,724,570	$27,239,644
Note payable – City of Niagara Falls	22,000,000	22,000,000	22,000,000
Note payable – Niagara Falls Hydro Holding Corporation	3,605,090	3,605,090	3,605,090
	$ 60,046,662	$ 59,329,660	$52,844,734

The notes payable bear interest at 5.32% 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, 2017. There is no immediate intent to redeem the notes payable and both notes payable are due April 2020.

The secured bank loans consist of the following:

	2015	2014	January 1, 2014
Scotiabank loan-fixed rate 6.44% due June 2014	$ -	$ -	$ 533,500
TD bank term loan-fixed rate 4.58% due July 2019	3,724,570	4,652,145	5,538,272
Scotiabank loan-fixed rate 2.67% due September 2020	2,137,500	2,587,500	3,037,500
TD loan-interest only-fixed rate 2.80% due June 2017	10,000,000	10,000,000	10,000,000
TD loan-interest only-fixed rate 2.933% due December 2018	10,000,000	10,000,000	10,000,000
TD loan-interest only-fixed rate 2.633% due November 2019	10,000,000	10,000,000	0
	$ 35,862,070	$ 37,239,645	$29,109,272

Current portion of long-term debt	$ 1,420,498	$ 3,515,075	$ 1,869,628
	$ 1,420,498	$ 3,515,075	$ 1,869,628

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2015

13. 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 2015, the Corporation made employer contributions of $1,133,347 to OMERS (2014 - $1,122,340), of which $317,247 (2014 - $323,289) has been capitalized as part of PP&E and the remaining amount of $816,100 (2014 - $799,051) has been recognized in profit or loss. The Corporation estimates that a contribution of $1,088,649 to OMERS will be made during the next fiscal year.

As at December 31, 2015, OMERS had approximately 451,115 members, of whom 275,044 are current employees of the Corporation. The most recently available OMERS annual report is for the year ended December 31, 2015, which reported that the plan was 91.5% funded, with an unfunded liability of $7.1 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 remeasurements recognized for post-employment benefit plans.

Reconciliation of the obligation	2015	2014
Defined benefit obligation, beginning of year	$ 2,402,181	$ 2,315,668
Included in profit or loss		
Current service cost	99,642	90,724
Interest cost	112,655	108,448
	2,614,478	2,514,840
Benefits paid	(110,378)	(112,659)
Defined benefit obligation, end of year	$ 2,504,100	$ 2,402,181

Actuarial assumptions	2015	2014
General inflation	2.00%	2.00%
Discount (interest) rate	4.80%	4.80%
Salary levels	3.10%	3.10%
Medical Costs	6.70%	7.00%
Dental Costs	4.60%	4.60%

A 1% increase in the assumed discount rate would result in the defined benefit obligation decreasing to $2,214,000. A 1% decrease in the assumed discount rate would result in the defined benefits obligation increasing to $2,866,000.

NIAGARA PENINSULA ENERGY INC.

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Year ended December 31, 2015

14. Share capital

	2015	2014
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 $1,200 per share (2014 - $1,200), which amount to total dividends paid in the year of $1,200,000 (2014 - $1,200,000).

15. Other revenue

	2015	2014
Pole rental revenue	$ 253,234	$ 253,345
Interest charges on hydro sales	424,468	405,422
Collection & reconnection charges	281,667	245,032
Occupancy change charge	188,670	189,900
Services for water billing	0	184,809
Miscellaneous service revenues	149,246	185,913
Miscellaneous non-operating revenue	103,532	105,336
Contributions received from customers	613,263	514,543
Government grants under CDM programs	114,410	245,502
Government grant expenditures under CDM programs	(114,410)	(245,502)
Performance incentive payments under CDM programs	278,313	5,746
Gain/loss on disposal of property, plant & equipment	29,600	8,500
	$ 2,321,993	$ 2,098,546

16. Operating expenses

	2015	2014
Salaries, wages and benefits	$ 9,428,357	$ 8,933,677
Materials and supplies	148,286	161,866
Vehicle expenditures	320,978	325,280
Outside purchases	6,684,636	6,418,154
Bad Debt expenses	285,116	258,260
Depreciation and amortization	7,188,553	7,293,500
	$ 24,055,926	$ 23,390,737

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
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17. Finance income and costs

	2015	2014
Finance income		
Interest income on bank deposits	$ 105,631	$ 116,333
Finance costs		
Interest expense on long-term debt	1,138,961	979,089
Interest expense on debt to associated companies	1,362,191	1,362,191
Interest expense on customer deposits	14,667	14,242
Other	8,451	0
	2,524,270	2,355,522
Net finance costs recognized in profit or loss	$ 2,418,639	$ 2,239,189

18. 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 company has arranged for a standby letter of credit of $12,000,000 (2014 - $12,000,000) of which $11,910,187 (2014 - $11,910,187) has been drawn down. The Independent Electricity Market Operator is the beneficiary for $11,910,187 (2014 - $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, 2015, no assessments have been made.

19. 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, 2015

19. Related party transactions (continued)

(a) Outstanding balances with related parties included in Due to related parties:

	2015	2014	January 1, 2014
Niagara Falls Hydro Services Inc.	$ 0	$ 0	$ (6,913,022)
Peninsula West Services Ltd.	(7,355)	(23,575)	0
	$ (7,355)	$ (23,575)	$ (6,913,022)

These balances are non-interest bearing with no fixed repayment terms.

(b) Outstanding balances with related parties included in Due from related parties:

	2015	2014	January 1, 2014
Niagara Falls Hydro Holding Corporation	$ 0	$ 4,771	$ 0
Niagara Falls Hydro Services Inc.	0	1,080	0
Peninsula West Services Ltd.	0	0	2,100
	$ 0	$ 5,851	$ 2,100

(c) Transactions with ultimate parent

	2015	2014
Revenue:		
Energy sales (at commercial rates)		
City of Niagara Falls	$ 2,726,229	$ 2,440,096
Town of Lincoln	431,727	413,408
Township of West Lincoln	242,905	230,132
Town of Pelham	50,173	46,956
Water billing and collecting services		
City of Niagara Falls	0	372,414
	$ 3,451,034	$ 3,503,006

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
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19. Related party transactions (continued)

(c) Transactions with ultimate parent (continued)

		2015		2014
Expenses:				
Property taxes				
City of Niagara Falls	$	165,288	$	165,706
Town of Lincoln		2,059		1,989
Township of West Lincoln		79,850		78,688
Town of Pelham		627		630
Water expenses				
City of Niagara Falls		12,340		5,452
Township of West Lincoln		4,200		3,194
	$	264,364	$	255,659

(d) Transaction with parent

		2015		2014
Revenue:				
Accounting services				
Peninsula West Power Inc.	$	1,000	$	1,000
Peninsula West Services Ltd.		25,120		30,470
Expenses:				
Other miscellaneous expenses				
City of Niagara Falls		3,358		2,487
Township of West Lincoln		600		765
Town of Pelham		3,270		4,905
	$	18,892	$	23,313

(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:

		2015		2014
Directors' fees	$	83,023	$	66,500
Salaries and other short-term benefits		1,339,853		1,305,055
	$	1,422,876	$	1,371,555

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2015

20. Financial instruments and risk management

Fair value disclosure

The carrying values of cash and cash equivalents, accounts receivable, unbilled revenue, due from/to related parties 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, 2015 is $58,370,000 (2014 - $56,528,000). 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, 2015 was 3.94% (2014 – 4.32%).

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, 2015 is $495,427 (2014 - $496,231). An impairment loss of $0 (2014 - $0) 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, 2015, approximately $560,261(2014- $641,759) is considered 60 days past due. The Corporation has over 52,000 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, 2015, the Corporation holds security deposits in the amount of $1,495,704 (2014 - $1,457,139).

20. 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, 2015, 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 (2014 - $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, 2015, shareholder's equity amounts to $86,222,035 (2014 - $84,856,519) and long-term debt amounts to $60,046,662 (2014 - $59,329,660).

21. Explanation of transition to IFRS

As stated in note 2(b), these are the Corporation's first financial statements prepared in accordance with IFRS.

The accounting policies set out in note 3 have been applied in preparing the financial statements for the year ended December 31, 2015, the comparative information presented in these financial statements for the year ended December 31, 2014, and in the preparation of the opening IFRS statement of financial position as at January 1, 2014 (the Corporation's date of transition).

In preparing its opening IFRS statement of financial position, the Corporation has adjusted the amounts reported previously in the financial statements prepared in accordance with Canadian general accepted accounting principles (CGAAP). An explanation of how the transition from CGAAP to IFRS has affected the Corporation's financial position, financial performance and cash flows is set out in the following tables and the notes accompanying the tables.

Regulatory accounts

IFRS 14: *Regulatory Deferral Accounts*, permits an entity to continue to account for regulatory deferral account balances in its financial statements in accordance with its previous GAAP when it adopts IFRS. An entity is permitted to apply the requirements of this standard in its first IFRS financial statements if and only if it conducts rate-regulated activities and recognized amounts that qualify as regulatory deferral account balances in its financial statements in accordance with its previous GAAP. This standard exempts an entity from applying paragraph 11 of IAS 8: *Accounting policies, changes in accounting estimates and errors*, to its accounting policies for the recognition, measurement, impairment and derecognition of regulatory deferral account balances.

IFRS 14 is effective from periods beginning on or after January 1, 2016, however, early application is permitted. The Corporation has elected to apply this Standard in its first IFRS financial statements.

IFRS 1 Exemptions

IFRS 1 *First-time adoption of International Financial Reporting Standards* sets out the procedures that the Corporation must follow when it adopts IFRS for the first time as the basis for preparing its financial statements. The Corporation is required to establish its IFRS accounting policies as at December 31, 2015 and, in general, apply these retrospectively to determine the IFRS opening statement of financial position as its date of transition, January 1, 2014. This standard provides a number of mandatory and optional exemptions to this general principle. These are set out below, together with a description in each case of the exemption adopted by the Corporation.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2015

21. Explanation of transition to IFRS (continued)

(a) Deemed cost

IFRS 1 provides an optional exemption for a first-time adopter with rate-regulated activities to use the carrying amount of PP&E and intangible assets as deemed cost on transition date when the carrying amount includes costs that do not quality for capitalization in accordance with IFRS. The Corporation elected this exemption and used the carrying amount of the PP&E and intangible assets under CGAPP as deemed cost on transition date. The carrying amount used as deemed cost is $140,574,794 for PP&E and $381,723 for intangible assets.

If an entity applies this exemption, at the date of transition to IFRS, it shall test for impairment each item for which this exemption is used. The assets were tested for impairment at the date of transition and it was determined that the assets were not impaired.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2015

21. Explanation of transition to IFRS (continued)

Reconciliation of statement of financial position and statement of changes in equity

January 1, 2014	Note	CGAAP	Presentation differences	Measurement & recognition differences	IFRS
Cash and cash equivalents	-	$ 11,481,267	$ 0	$ 0	$ 11,481,267
Accounts receivable	-	10,537,974	545,704	0	11,083,678
Due from related parties	-	2,100	0	0	2,100
Unbilled revenue	-	16,625,610	211,950	0	16,837,560
Income taxes receivable	-	1,520,859	0	0	1,520,859
Materials and supplies	-	1,621,583	0	0	1,621,583
Prepaid expenses	-	829,213	0	0	829,213
Property, plant and equipment	a,b,c,d	125,876,014	14,698,780	0	140,574,794
Intangible assets	-	381,723	0	0	381,723
Deferred tax assets	e	1,080,652	(354,494)	(726,158)	0
Total assets	-	169,956,995	15,101,940	(726,158)	184,332,777
Regulatory balances	-	0	14,183,499	1,169,597	15,353,096
Total assets and regulatory balances		$ 169,956,995	$ 29,285,439	$ 443,439	$ 199,685,873
Accounts payable and accrued liabilities	-	$ 15,473,628	$ (734,538)	$ 0	$ 14,739,090
Due to related parties	-	6,913,022	0	0	6,913,022
Long-term debt due within a year	-	1,869,628	0	0	1,869,628
Customer deposits	-	1,456,011	0	0	1,456,011
Deferred revenue	c	0	1,299,695	0	1,299,695
Long-term debt	-	52,844,734	0	0	52,844,734
Employees' vested sick leave	-	112,861	0	0	112,861
Post-employment benefits	f	3,886,289	0	(1,570,621)	2,315,668
Deferred capital contributions	-	0	14,891,276	0	14,891,276
Deferred tax liabilities	e	0	246,001	0	246,001
Total liabilities	-	82,556,173	15,702,434	(1,570,621)	96,687,986
Share capital	-	31,245,882	0	0	31,245,882
Contributed surplus	-	25,459,207	0	0	25,459,207
Retained earnings	-	26,588,420	0	443,439	27,031,859
Total liabilities and equity	-	165,849,682	15,702,434	(1,127,182)	180,424,934
Regulatory balances	f	4,107,313	13,583,005	1,570,621	19,260,939
Total liabilities, equity and regulatory balances		$ 169,956,995	$ 29,285,439	$ 443,439	$ 199,685,873

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2015

21. Explanation of transition to IFRS (continued):

Reconciliation of statement of financial position and statement of changes in equity

December 31, 2014	Note	CGAAP	Presentation differences	Measurement & recognition differences	IFRS
Cash and cash equivalents	-	$ 10,592,335	$ 0	$ 0	$ 10,592,335
Accounts receivable	-	12,410,725	1,076,761	0	13,487,486
Due from related parties	-	5,851	0	0	5,851
Unbilled revenue	-	16,220,588	241,936	0	16,462,524
Income taxes receivable	-	1,061,929	0	0	1,061,929
Material and supplies	-	1,481,014	0	0	1,481,014
Prepaid expenses	-	768,260	0	0	768,260
Property, plant and equipment	a,b,c,d	133,483,443	15,181,182	0	148,664,625
Intangible assets	-	427,552	0	0	427,552
Deferred tax assets	e	1,204,168	0	(1,204,168)	0
Total assets	-	177,655,865	16,499,879	(1,204,168)	192,951,576
Regulatory balances	-	0	10,401,095	3,128,872	13,529,967
Total assets and regulatory balances		$177,655,865	$ 26,900,974	$ 1,924,704	$ 206,481,543
Accounts payable and accrued Liabilities	-	$ 19,526,239	$ 797,946	$ 20,000	$ 20,344,185
Due to related parties	-	23,575	0	0	23,575
Long-term debt due within one year	-	3,515,075	0	0	3,515,075
Customer deposits	-	1,494,473	0	0	1,494,473
Deferred revenue	c	0	456,557	0	456,557
Long-term debt	-	59,329,660	0	0	59,329,660
Employees' vested sick leave	-	50,135	0	0	50,135
Post-employment benefits	f	3,907,283	0	(1,505,102)	2,402,181
Deferred capital contributions	-	0	15,245,377	358,996	15,604,373
Deferred tax liabilities	e	0	0	612,127	612,127
Total liabilities	-	87,846,440	16,499,880	(513,979)	103,832,341
Share capital	-	31,245,882	0	0	31,245,882
Contributed surplus	-	25,459,207	0	0	25,459,207
Retained earnings	-	27,735,492	0	415,938	28,151,430
Total liabilities and equity	-	172,287,021	16,499,880	(98,041)	188,688,860
Regulatory balances	f	5,368,844	10,401,094	2,022,745	17,792,683
Total liabilities, equity and regulatory balances		$177,655,865	$ 26,900,974	$ 1,924,704	$ 206,481,543

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2015

21. Explanation of transition to IFRS (continued)

Reconciliation of net income for 2014

	Note	CGAAP	Presentation differences	Measurement & recognition differences	IFRS
Revenue					
Sale of energy	-	$136,846,497	$ 0	$ 0	$ 136,846,497
Distribution revenue	-	30,449,316	(4,799,091)	0	25,650,225
Other	c,d	1,966,674	131,872	0	2,098,546
		169,262,487	(4,667,219)	0	164,595,268
Operating expenses					
Cost of power purchased	-	136,846,497	135,350	0	136,981,847
Distribution and maintenance	-	6,593,806	(73,775)	0	6,520,031
Utilization expenses	-	205,566	0	0	205,566
Billing and collecting expenses	-	5,937,901	(1,062,149)	0	4,875,752
Administration and general	f	7,017,646	(2,587,277)	65,519	4,495,888
Depreciation and amortization	c	5,649,681	544,181	0	6,193,862
Depreciation on FMV bump	-	1,099,638	0	0	1,099,638
Finance income	-	0	(116,333)	0	(116,333)
Finance costs	b	0	2,355,522	0	2,355,522
Income tax expense	e	449,350	133,310	356,333	938,993
		163,800,085	(671,171)	421,852	163,550,766
Net income for the year	-	5,462,402	(3,996,048)	(421,852)	1,044,502
Net movement in regulatory balances, net of tax	e	(3,115,330)	3,996,048	394,351	1,275,069
Net income, net movement in regulatory balances and comprehensive income		$ 2,347,072	$ 0	$ (27,501)	$ 2,319,571

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2015

21. Explanation of transition to IFRS (continued)

Notes to the reconciliations

The impact on deferred tax of the adjustments described below is set out in note (e).

a. The Corporation has elected under IFRS 1 to use the carrying value of items of PP&E and intangible assets as the deemed cost at the date of transition. Therefore, there has been no change to the net PP&E and intangible assets at January 1, 2014. The effect of this transitional adjustment is a decrease to the original cost and accumulated depreciation of the affected PP&E and intangible assets by $125,030,322 and $4,091,797 respectively, the CGAAP accumulated depreciation amount, on January 1, 2014.

b. IFRS requires that borrowing costs related to the construction of the qualifying assets be capitalized. The Corporation has applied IAS 23 to all qualifying assets that were in progress or commenced since January 1, 2014. No qualifying assets were identified and therefore no borrowing costs were capitalized for the year ended December 31, 2014.

c. Under CGAAP, customer contributions were netted against the cost of PP&E and amortized to profit or loss as an offset to depreciation expense, on the same basis as the related assets. Under IFRS, customer contributions are recognized as deferred revenue, not netted against PP&E, and amortized into profit or loss over the life of the related asset.

   The effect of the above is to increase deferred revenue by $14,891,276 at January 1, 2014 and by $15,604,373 at December 31, 2014; to increase PP&E by $15,181,182 at December 31, 2014 and to increase other revenue and depreciation expense by $514,543 for the year ended December 31, 2014.

d. Under CGAAP for rate regulated entities, the Corporation removed assets from the accounts at the end of their estimated useful lives. IFRS requires assets to be removed from the accounts when they have been removed from service.

   The effect is to decrease PP&E by $0 at December 31, 2014 and to increase loss on retirement of PP&E by $0 for the year ended December 31, 2014.

e. The above changes increase (decreased) the deferred tax asset as follows based on a tax rate of 26.5%:

	2014	January 1, 2014
Property, plant and equipment	$ 0	$ 0
Cumulative eligible capital	0	0
Post-employee benefits	(393,552)	(416,214)
Regulatory gross up	(142,881)	(309,944)
Increase (decrease) in deferred tax asset	$ 536,433	$ 726,158

   The effect on the statement of comprehensive income for the year ended December 31, 2014 was to decrease the previously reported income taxes by $(394,351).

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2015

21. Explanation of transition to IFRS (continued)

f. The Corporation adopted the revised Employee Benefits standard effective January 1, 2014. This revised standard requires recognition of actuarial gains and losses through other comprehensive income. This decreased post-employment benefits and increased Regulatory liabilities by $(1,570,621) at January 1, 2014 and, decreased operating expenses by $65,519 and increased post-employment benefits by $1,505,102 at December 31, 2014.

Explanation of material adjustments to the statement of cash flows for 2014

There are no material differences between the statement of cash flows presented under IRFS and the statement of cash flows presented under CGAAP.

Appendix 1-32

Financial Statement Reconciliations 2014 to 2019

Niagara Peninsula Energy Inc.
For the Twelve Months Ending December 31, 2019

RRR Part 1
Trial Balance Mapped to Financial Statement Grouping
2.1.13

	RRR = Financial Statements December 2019	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry presentation on FS	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
1005 Cash	11,883,520.29				11,883,520.29		
1010 Cash Advance and Working Funds	2,326.98	11,885,847.27			2,326.98	11,885,847.27	
1100 Custom Accounts Receivable	16,256,759.80				16,256,759.80		
1104 Accounts Receivable - Recoverable Work	1,446,411.79				1,446,411.79		
1110 Other Accounts Receivable	1,004,417.56				1,004,417.56		
2290 Commodity Taxes	1,746,185.77				1,746,185.77		
1130 Accumulated Provision for Uncollectible Accts	(701,019.03)	19,752,755.89			(701,019.03)	19,752,755.89	
1120 Accrued Utility Revenues	13,805,772.46	13,805,772.46			13,805,772.46	13,805,772.46	
1200 Accounts Receivable from Associated Companies	8,655.91	8,655.91			8,655.91	8,655.91	
2294 Accrual for Taxes,"Payments in Lieu"of Taxes	784,449.50	784,449.50			784,449.50	784,449.50	
1180 Prepayments	1,307,763.10				1,307,763.10		
1606 Organization	0.00	1,307,763.10		1,926.45	1,926.45	1,309,689.55	
1330 Plant Materials and Operating Supplies	1,444,522.97	1,444,522.97	48,989,767.10		1,444,522.97	1,444,522.97	48,991,693.55
1606 Organization	1,926.45			(1,926.45)	0.00		
1705 Land	82,347.02				82,347.02		
1708 Buildings and Fixtures	3,785,228.83				3,785,228.83		
1715 Station Equipment	3,042,173.68				3,042,173.68		
1735 Underground Conduit	1,090.59				1,090.59		
1740 Underground Conductors and Devices	138,793.40				138,793.40		
1805 Land	424,925.77				424,925.77		
1612 Land Rights	1,604,396.58				1,604,396.58		
1808 Buildings and Fixtures	111,638.13				111,638.13		
1815 Transformer Station Equipment - Normally Primary	77,002.22				77,002.22		
1820 Distribution Station Equipment - Normally Primary	7,119,637.20				7,119,637.20		
1830 Poles, Towers and Fixtures	55,805,804.34				55,805,804.34		
1835 Overhead Conductors and Devices	40,965,808.68				40,965,808.68		
1840 Underground Conduit	14,778,417.24				14,778,417.24		
1845 Underground Conductors and Devices	84,081,172.78			1,734,098.95	85,815,271.73		
1850 Line Transformers	47,369,900.05			578,032.98	47,947,933.03		
1855 Services	12,779,083.96				12,779,083.96		
1860 Meters	12,633,007.52				12,633,007.52		
1865 Other Installations on Customer's Premises	439.87				439.87		
1875 Street Lighting and Signal Systems	21,835.21				21,835.21		
1905 Land	508,969.83				508,969.83		
1908 Buildings and Fixtures	20,717,683.18				20,717,683.18		
1915 Office Furniture and Equipment	1,941,662.29				1,941,662.29		
1920 Computer Equipment-Hardware	5,395,891.54				5,395,891.54		
1930 Transportation Equipment	10,321,378.07				10,321,378.07		
1935 Stores Equipment	328,494.50				328,494.50		
1940 Tools, Shop and Garage Equipment	2,447,550.25				2,447,550.25		
1945 Measurement and Testing Equipment	204,006.18				204,006.18		
1955 Communication Equipment	1,593,239.00				1,593,239.00		
1960 Miscellaneous Equipment	72,951.31				72,951.31		
1980 System Supervisory Equipment	128,960.64				128,960.64		
2005 Property Under Capital Leases	143,036.00				143,036.00		
2060 Electric Plant Acquisition Adjustment	142,276.60				142,276.60		
2065 Other Electric Plant Adjustment	0.00			44,693,820.53	44,693,820.53		
2105 Accumulated Amortization of Electric Utility-Plant	(152,986,820.30)				(152,986,820.30)		
2140 Accumulated Amortization of Electric Plant	(142,276.60)				(142,276.60)		
2160 Accumulated Amortization of Other Utility Plant	0.00	175,641,632.01	175,641,632.01	(37,139,837.39)	(37,139,837.39)	185,505,820.63	
1910 Leasehold Improvements	120,252.32				120,252.32		
1611 Computer Software	5,116,350.89				5,116,350.89		
2120 Accumulated Amortization of Electric Utility Plant-Intangibles	(5,655,864.12)	(419,260.91)	(419,260.91)	815,694.91	(4,840,169.21)	396,434.00	
1495 Other Assets and Deferred Charges	15,895,547.14	15,895,547.14	15,895,547.14	(5,241,161.77)	10,654,385.37	10,654,385.37	196,556,640.00
1508 Other Regulatory Assets	(488,566.94)			748,270.83	259,703.89		

	RRR = Financial Statements December 2019	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry presentation on FS	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
1495 Deferred Taxes-Non-current assets	0.00			5,241,161.77	5,241,161.77		
1550 Hydro One Low Voltage Variance	1,961,260.13				1,961,260.13		
1555 Smart Meter Capital and Recovery Variance	0.00				0.00		
1584 RSVA - NW	359,953.97				359,953.97		
1586 RSVA - CN	87,195.90				87,195.90		
1588 RSVA - Power	0.00				0.00		
1589 RSVA - GA Non-RPP	7,714.38				7,714.38		
1518 RCVA - Retail	109,953.45				109,953.45		
1548 RCVA - STR	374,472.58				374,472.58		
1557 Mist meter variance	83,183.45				83,183.45		
1568 LRAM variance	0.00				0.00		
1535 Smart Grid Deferral Account	0.00				0.00		
1595 Disposition and Recovery of Regulatory Balances	0.00	2,495,166.92	2,495,166.92	4,623.41	4,623.41	8,489,222.93	8,489,222.93
2205 Accounts Payable	(8,323,381.68)				(8,323,381.68)		
2250 Debt Retirement Charges DRC payable	0.00				0.00		
2256 Independent Market Operator Fees and Penalties	(11,140,317.31)				(11,140,317.31)		
2264 Pensions and Employee Benefits-Current Portion	(193,144.08)				(193,144.08)		
2290 Commodity Taxes	0.00				0.00		
2292 Payroll Deductions/Expenses Payable	(727.02)	(19,657,570.09)			(727.02)	(19,657,570.09)	
2210 Current portion of customer deposits	(1,410,029.02)				(1,410,029.02)		
2320 Other Miscellaneous Non-current liabilities	(37,334.17)	(1,447,363.19)			(37,334.17)	(1,447,363.19)	
2220 Miscellaneous Current and Accrued Liabilities	0.00				0.00		
2425 Other Deferred Credits	(1,099,095.14)	(1,099,095.14)			(1,099,095.14)	(1,099,095.14)	
2294 Accrual for Taxes,"Payments in Lieu"of Taxes	0.00	0.00		0.00	0.00	0.00	
2210 Current portion of Customer deposits	0.00	0.00			0.00	0.00	
2240 Accounts Payable to Associated Companies	0.00	0.00			0.00	0.00	
2260 Current Portion of Long Term Debt	(1,044,471.77)	(1,044,471.77)	(23,248,500.19)		(1,044,471.77)	(1,044,471.77)	(23,248,500.19)
2520 Other Long Term debt	0.00				0.00		
2525 Term Bank Loans-long term Portion	(82,834,630.20)				(82,834,630.20)		
2550 Advances from Associated Companies	0.00	(82,834,630.20)			0.00	(82,834,630.20)	
2335 Long Term Customer Deposits	0.00	0.00			0.00		
2310 Vested Sick Leave Liability	(63,841.86)	(63,841.86)			(63,841.86)	(63,841.86)	
2306 Employee Future Benefits	(4,780,183.03)	(4,780,183.03)			(4,780,183.03)	(4,780,183.03)	
1995 Contributions and Grants - Credit	(29,323,463.26)	(29,323,463.26)		(2,312,131.93)	(31,635,595.19)	(31,635,595.19)	
2350 Future Income Tax - non current	(13,541,389.19)	(13,541,389.19)	(130,543,507.54)		(13,541,389.19)	(13,541,389.19)	(132,855,639.47)
2405 Other Regulatory liabilities	(1,518,825.50)				(1,518,825.50)		
1508 Other Regulatory Assets - OPEB	0.00			(748,270.83)	(748,270.83)		
1522 OPEB Forecast vs Actual Differential	(74.60)				(74.60)		
1551 Smart Metering Entity Variance	(32,269.16)				(32,269.16)		
1555 Smart Meter Capital and Recovery Variance	(24,682.86)				(24,682.86)		
1576 Accounting Changes Under CGAAP	(160,882.11)				(160,882.11)		
1580 RSVA - WMS	(776,720.92)				(776,720.92)		
1582 RSVA - One Time	0.00				0.00		
1586 RSVA - CN	0.00				0.00		
1588 RSVA - Power	(1,309,174.11)				(1,309,174.11)		
1589 RSVA - GA Non-RPP	0.00				0.00		
1562 Deferred Payments in Lieu of taxes	0.00				0.00		
1563 Deferred PILS contra Account	0.00				0.00		
1557 Mist meter variance	0.00				0.00		
1521 Special Purpose Charge	0.00				0.00		
1595 Disposition and Recovery of Regulatory Balances	(395,258.49)	(4,217,887.75)	(4,217,887.75)	(4,623.41)	(399,881.90)	(4,970,781.99)	(4,970,781.99)
3005 Common Shares Issued	(31,245,882.02)	(31,245,882.02)			(31,245,882.02)	(31,245,882.02)	
3010 Contributed Surplus	0.00			(18,753,902.09)	(18,753,902.09)		
3047 Appropriations of Retained Earnings - current	(6,705,305.00)	(6,705,305.00)			(6,705,305.00)	(25,459,207.09)	
3040 Appropriated Retained Earnings	(45,670,877.25)			9,337,549.54	(36,333,327.71)		
3041 Appropriated Retained Earnings							
3046 Balance Transferred from Income	(2,370,892.51)			1,046,674.50	(1,324,218.01)		
3049 Dividends payable - Common Shares	1,400,000.00	(46,641,769.76)	(84,592,956.78)		1,400,000.00	(36,257,545.72)	(92,962,634.83)
Balance Sheet	**(0.00)**	**0.00**	**0.00**	**0.00**	**(0.00)**	**(0.00)**	**0.00**

	RRR = Financial Statements December 2019	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry presentation on FS	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
4006 Residential Energy Sales	(33,875,648.85)			2,637,163.83	(31,238,485.02)		
4010 Commercial Energy Sales	(13,706,262.32)				(13,706,262.32)		
4025 Streetlighting energy sales	(569,523.62)				(569,523.62)		
4030 Sentinel Lighting Energy Sales	(1,405.14)				(1,405.14)		
4035 General Energy Sales	(78,115,247.61)				(78,115,247.61)		
4062 Billed WMS	(4,923,599.96)				(4,923,599.96)		
4066 Billed NW	(8,217,712.85)				(8,217,712.85)		
4068 Billed CN	(6,038,759.85)				(6,038,759.85)		
4075 Billed - LV	(535,008.93)				(535,008.93)		
4076 Billed SME Charge	(375,434.48)	(146,358,603.61)	(146,358,603.61)		(375,434.48)	(143,721,439.78)	(143,721,439.78)
4080 Distribution Services Revenue	(30,515,032.93)				(30,515,032.93)		
4082 Retail Services Revenue	(38,661.60)				(38,661.60)		
4084 Service Transaction Requests (STR) Revenues	(585.50)				(585.50)		
4086 SSS Admin Charge	(160,439.85)	(30,714,719.88)	(30,714,719.88)		(160,439.85)	(30,714,719.88)	(30,714,719.88)
4215 Other Utility Operating Income	(19,293.92)				(19,293.92)		
4225 Late Payment Charges	(336,173.09)				(336,173.09)		
4235 Miscellaneous Service Revenues	(1,659,526.07)			(460,155.41)	(2,119,681.48)		
4355 Gain on Disposition of Utility and Other Property	(265.49)				(265.49)		
4360 Loss on Disposition of Utility and Other Property	68,274.80				68,274.80		
4362 Loss on Retirement of Utility and Other Property	6,135.26				6,135.26		
4375 Revenues from Non-Utility Operations	(1,604,938.35)				(1,604,938.35)		
4380 Expenses from Non-Utility Operations	1,604,938.35				1,604,938.35		
4390 Miscellaneous Non-Operating Income	(34,166.00)	(1,975,014.51)	(1,975,014.51)		(34,166.00)	(2,435,169.92)	(2,435,169.92)
4705 Power Purchased	61,169,795.48			(1,982,327.49)	59,187,467.99		
4707 Global adjustment purchased	65,098,292.06				65,098,292.06		
4708 Charges -WMS	4,923,599.96				4,923,599.96		
4714 Charges -NW	8,217,712.85				8,217,712.85		
4716 Charges -CN	6,038,759.85				6,038,759.85		
4751 Charges -SME	535,008.93				535,008.93		
4750 Charges - LV	375,434.48	146,358,603.61	146,358,603.61		375,434.48	144,376,276.12	144,376,276.12
5005 Operation Supervision and Engineering	990,133.31				990,133.31		
5010 Load Dispatching	9,123.75				9,123.75		
5012 Station Buildings and fixtures expense	147,870.00				147,870.00		
5014 Transformer Station Equipment - Operation Labour	45,103.86				45,103.86		
5015 Transformer Station Equipment - Operation	163,497.75				163,497.75		
5020 Overhead Distribution Lines and Feeders -Labour	293,751.30				293,751.30		
5025 Overhead Distribution Lines and Feeders - Operation expenses	107,226.32			100,295.18	207,521.50		
5040 Underground Distribution Lines and Feeders Labour	199,189.56				199,189.56		
5045 Underground Distribution Lines and Feeders - expenses	379,342.57				379,342.57		
5055 Underground Distribution Transformer - Operations	0.00				0.00		
5065 Meter Expense	397,351.34				397,351.34		
5085 Miscellaneous Distribution Expenses	2,121,355.75				2,121,355.75		
5105 Maintenance Supervision and Engineering	457,769.37				457,769.37		
5112 Maintenance of Transformer Station Equipment	3,949.71				3,949.71		
5114 Maintenance of Distribution Station Equipment	22,933.12				22,933.12		
5120 Maintenance of Poles, Towers and Fixtures	117,003.24				117,003.24		
5125 Maintenance of Overhead Conductors and Devices	914,429.03				914,429.03		
5130 Maintenance of Overhead Services	271,956.28				271,956.28		
5135 Overhead Distribution Lines and Feeders - Right of Way	371,116.35				371,116.35		
5145 Maintenance of Underground Conduit	39,289.46				39,289.46		
5150 Maintenance of Underground Conductors & Devices	220,252.95				220,252.95		
5155 Maintenance of Underground Services	177,100.80				177,100.80		
5160 Maintenance of Line Transformers	82,773.18				82,773.18		
5175 Maintenance of Meters	0.00	7,532,519.00			0.00	7,632,814.18	7,632,814.18
5070 Customer Premises - Operation Labour	131,731.60				131,731.60		
5405 Supervision	0.00				0.00		
5410 Community Relations - Sundry	133,275.75	265,007.35			133,275.75	265,007.35	265,007.35
5305 Supervision	1,209,734.14				1,209,734.14		

	RRR = Financial Statements December 2019	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry presentation on FS	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
5310 Meter Reading Expense	586,734.21			121,501.25	708,235.46		
5315 Customer Billing	3,147,231.13				3,147,231.13		
5320 Collecting	441,420.21				441,420.21		
5325 Collecting - Cash Over and Short	(182.52)				(182.52)		
5335 Bad Debt Expense	343,782.55				343,782.55		
5340 Miscellaneous Customer Accounts Expense	237,356.49	5,966,076.21		80,162.52	317,519.01	6,167,739.98	6,167,739.98
5605 Executive Salaries and Expenses	526,832.92				526,832.92		
5610 Management Salaries and Expenses	2,501,907.09			98,270.57	2,600,177.66		
5615 General Administrative Salaries and Expenses	523,112.47				523,112.47		
5620 Office Supplies and Expenses	84,413.76				84,413.76		
5630 Outside Services Employed	53,000.04				53,000.04		
5635 Property Insurance	304,314.97				304,314.97		
5655 Regulatory Expenses	267,824.34				267,824.34		
5665 Miscellaneous General Expense	79,372.59				79,372.59		
5675 Maintenance of General Plant	710,523.30				710,523.30		
6105 Taxes other that Income Taxes	228,722.39				228,722.39		
6205 Donations	74,036.00	5,354,059.87			74,036.00	5,452,330.44	5,452,330.44
5705 Amortization Expense - Property Plant and Equipment	7,818,837.47	7,818,837.47		0.00	7,818,837.47	7,818,837.47	7,818,837.47
5715 Amortization of Intangibles and Other Electric	0.00	0.00		1,046,674.50	1,046,674.50	1,046,674.50	1,046,674.50
4405 Interest and Dividend Income	(311,867.81)	(311,867.81)		86,812.51	(225,055.30)	(225,055.30)	(225,055.30)
6005 Interest on Long Term Debt	1,799,900.41				1,799,900.41		
6030 Interest on Debt to Associated Companies	712,461.89				712,461.89		
6035 Other Interest Expense	240,891.93	2,753,254.23	29,377,886.32	(79,298.80)	161,593.13	2,673,955.43	2,673,955.43
6215 Penalties	0.00				0.00		
6110 Income Taxes	(353,819.07)				(353,819.07)	(353,819.07)	(353,819.07)
6115 Provision for Future Income Taxes	1,294,774.63	940,955.56	940,955.56	(368,637.00)	926,137.63	926,137.63	926,137.63
Net Income for the year	**(2,370,892.51)**	**(2,370,892.51)**	**(2,370,892.51)**	**1,280,461.66**	**(1,090,430.85)**	**(1,090,430.85)**	**(1,090,430.85)**
Net movement in regulatory balances, net of tax	0.00	0.00	0.00	(233,787.98)	(233,787.98)	(233,787.98)	(233,787.98)
Net income, net movement in regulatory balances	**(2,370,892.51)**	**(2,370,892.51)**	**(2,370,892.51)**	**1,046,673.68**	**(1,324,218.83)**	**(1,324,218.83)**	**(1,324,218.83)**
Other Comprehensive Income							
Remeasurements of post-employment benefits	337,322.37			0.00	337,322.37	337,322.37	337,322.37
Net movement in regulatory balances, net of tax	(337,322.37)			0.00	(337,322.37)	(337,322.37)	(337,322.37)
Other Comprehensive Income for the year	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Comprehensive income for the year	**(2,370,892.51)**	**(2,370,892.51)**	**(2,370,892.51)**	**1,046,673.68**	**(1,324,218.83)**	**(1,324,218.83)**	**(1,324,218.83)**
Trial Balance Summary							
Revenues	(179,048,338.00)	(179,048,338.00)	(179,048,338.00)	1,943,220.44	(177,105,117.56)	(177,105,117.56)	(177,105,117.56)
Expenses	176,677,445.49	176,677,445.49	176,677,445.49	(896,546.76)	175,780,898.73	175,780,898.73	175,780,898.73
(Profit)/Loss	(2,370,892.51)	(2,370,892.51)	(2,370,892.51)	1,046,673.68	(1,324,218.83)	(1,324,218.83)	(1,324,218.83)
Net Assets	209,795,877.25	208,277,051.75	238,384,964.51	8,369,678.05	218,165,555.30	216,646,729.80	249,066,774.49
Net Liabilities and Equity	(209,795,877.25)	(208,277,051.75)	(238,384,964.51)	(8,369,678.05)	(218,165,555.30)	(216,646,729.80)	(249,066,774.49)
IS (Profit)/Loss	(2,370,892.51)	(2,370,892.51)	(2,370,892.51)	1,046,673.68	(1,324,218.83)	(1,324,218.83)	(1,324,218.83)
Balance Sheet (profit)/Loss	(2,370,892.51)	(2,370,892.51)	(2,370,892.51)	1,046,674.50	(1,324,218.01)	(1,324,218.01)	(1,324,218.01)
	0.00	0.00	0.00	(0.82)	(0.82)	(0.82)	(0.82)

Niagara Peninsula Energy Inc.
For the Twelve Months Ending December 31, 2019
RRR Part 2
Trial Balance by Account
2.1.13

	Filed RRR excluding FMV entry	Adjustments for FMV entry presentation on FS	Audited Financial Statement December 2019
Current Assets			
1005 Cash	11,883,520.29		11,883,520.29
1010 Cash Advance and Working Funds	2,326.98		2,326.98
1100 Custom Accounts Receivable	16,256,759.80		16,256,759.80
1104 Accounts Receivable - Recoverable Work	1,446,411.79		1,446,411.79
1110 Other Accounts Receivable	1,004,417.56		1,004,417.56
1120 Accrued Utility Revenues	13,805,772.46		13,805,772.46
1130 Accumulated Provision for Uncollectible Accts	(701,019.03)		(701,019.03)
1180 Prepayments	1,307,763.10		1,307,763.10
1200 Accounts Receivable from Associated Companies	8,655.91		8,655.91
1330 Plant Materials and Operating Supplies	1,444,522.97		1,444,522.97
1495 Other Assets and Deferred Charges	15,895,547.14		15,895,547.14
1508 Other Regulatory Assets-Lead/Lag Study	(488,566.94)		(488,566.94)
1508 Other Regulatory Assets Incremental Capital Charges Hydro One	0.00		0.00
1508 Other Regulatory Assets - OPEB	0.00		0.00
1518 RCVA - Retail	109,953.45		109,953.45
1522 OPEB Forecast vs Actual Differential	(74.60)		(74.60)
1548 RCVA - STR	374,472.58		374,472.58
1550 Hydro One Low Voltage Variance	1,961,260.13		1,961,260.13
1551 Smart Metering Entity Variance	(32,269.16)		(32,269.16)
1555 Smart Meter Capital and Recovery Variance	(24,682.86)		(24,682.86)
1557 Mist meter variance	83,183.45		83,183.45
1568 LRAM variance	0.00		0.00
1576 Accounting Changes Under CGAAP	(160,882.11)		(160,882.11)
1580 RSVA - WMS	(776,720.92)		(776,720.92)
1584 RSVA - NW	359,953.97		359,953.97
1586 RSVA - CN	87,195.90		87,195.90
1588 RSVA - Power	(1,309,174.11)		(1,309,174.11)
1589 RSVA - GA Non-RPP	7,714.38		7,714.38
1595 Disposition and Recovery of Regulatory Balances	(395,258.49)		(395,258.49)
1606 Organization	1,926.45		1,926.45
1611 Computer Software	5,116,350.89		5,116,350.89
1612 Land Rights	1,604,396.58		1,604,396.58
1705 Land	82,347.02		82,347.02
1708 Buildings and Fixtures	3,785,228.83		3,785,228.83
1715 Station Equipment	3,042,173.68		3,042,173.68
1735 Underground Conduit	1,090.59		1,090.59
1740 Underground Conductors and Devices	138,793.40		138,793.40
1805 Land	424,925.77		424,925.77
1808 Buildings and Fixtures	111,638.13		111,638.13
1815 Transformer Station Equipment - Normally Primary	77,002.22		77,002.22
1820 Distribution Station Equipment - Normally Primary	7,119,637.20		7,119,637.20
1830 Poles, Towers and Fixtures	55,805,804.34		55,805,804.34
1835 Overhead Conductors and Devices	40,965,808.68		40,965,808.68
1840 Underground Conduit	14,778,417.24		14,778,417.24
1845 Underground Conductors and Devices	84,081,172.78	1,734,098.95	85,815,271.73
1850 Line Transformers	47,369,900.05	578,032.98	47,947,933.03
1855 Services	12,779,083.96		12,779,083.96
1860 Meters	12,633,007.52		12,633,007.52
1865 Other Installations on Customer's Premises	439.87		439.87
1875 Street Lighting and Signal Systems	21,835.21		21,835.21
1905 Land	508,969.83		508,969.83
1908 Buildings and Fixtures	20,717,683.18		20,717,683.18
1910 Leasehold Improvements	120,252.32		120,252.32
1915 Office Furniture and Equipment	1,941,662.29		1,941,662.29

	Filed RRR excluding FMV entry	Adjustments for FMV entry presentation on FS	Audited Financial Statement December 2019
1920 Computer Equipment-Hardware	5,395,891.54		5,395,891.54
1930 Transportation Equipment	10,321,378.07		10,321,378.07
1935 Stores Equipment	328,494.50		328,494.50
1940 Tools, Shop and Garage Equipment	2,447,550.25		2,447,550.25
1945 Measurement and Testing Equipment	204,006.18		204,006.18
1955 Communication Equipment	1,593,239.00		1,593,239.00
1960 Miscellaneous Equipment	72,951.31		72,951.31
1980 System Supervisory Equipment	128,960.64		128,960.64
1995 Contributions and Grants - Credit	(29,323,463.26)	(2,312,131.93)	(31,635,595.19)
2005 Property Under Capital Leases	143,036.00		143,036.00
2060 Electric Plant Acquisition Adjustment	142,276.60		142,276.60
2065 Other Electric Plant Adjustment	0.00	45,509,515.44	45,509,515.44
2105 Accumulated Amortization of Electric Utility-Plant	(152,986,820.30)		(152,986,820.30)
2120 Accumulated Amortization of Electric Utility Plant-Intangibles	(5,655,864.12)		(5,655,864.12)
2140 Accumulated Amortization of Electric Plant	(142,276.60)		(142,276.60)
2160 Accumulated Amortization of Other Utility Plant	0.00	(37,139,837.39)	(37,139,837.39)
2205 Accounts Payable	(8,323,381.68)		(8,323,381.68)
2256 Independent Market Operator Fees and Penalties	(11,140,317.31)		(11,140,317.31)
2210 Current portion of Customer deposits	(1,410,029.02)		(1,410,029.02)
2240 Accounts Payable to Associated Companies	0.00		0.00
2250 Debt Retirement Charges DRC payable	0.00		0.00
2260 Current Portion of Long Term Debt	(1,044,471.77)		(1,044,471.77)
2264 Pensions and Employee Benefits-Current Portion	(193,144.08)		(193,144.08)
2290 Commodity Taxes	1,746,185.77		1,746,185.77
2292 Payroll Deductions/Expenses Payable	(727.02)		(727.02)
2294 Accrual for Taxes,"Payments in Lieu"of Taxes	784,449.50		784,449.50
2296 Future Income Taxes - Current	0.00		0.00
2306 Employee Future Benefits	(4,780,183.03)		(4,780,183.03)
2310 Vested Sick Leave Liability	(63,841.86)		(63,841.86)
2320 Other Miscellaneous Non-current liabilities	(37,334.17)		(37,334.17)
2350 Future Income Tax - Non Current	(13,541,389.19)		(13,541,389.19)
2405 Other Regulatory Liabilities	(1,518,825.50)		(1,518,825.50)
2425 Other Deferred Credits	(1,099,095.14)		(1,099,095.14)
2525 Term Bank Loans-long term Portion	(82,834,630.20)		(82,834,630.20)
2550 Advances from Associated Companies	0.00		0.00
3005 Common Shares Issued	(31,245,882.02)		(31,245,882.02)
3010 Contributed Surplus	0.00	(18,753,902.09)	(18,753,902.09)
3040 Appropriated Retained Earnings	(45,670,877.25)	9,337,549.54	(36,333,327.71)
3046 Balance Transferred from Income	(2,370,892.51)	1,046,674.50	(1,324,218.01)
3047 Appropriations of Retained Earnings - current	(6,705,305.00)		(6,705,305.00)
3049 Dividends payable - Common Shares	1,400,000.00		1,400,000.00
Balance Sheet	0.00	(0.00)	(0.00)

4006 Residential Energy Sales	(33,875,648.85)	2,637,163.83	(31,238,485.02)
4010 Commercial Energy Sales	(13,706,262.32)		(13,706,262.32)
4025 Streetlighting energy sales	(569,523.62)		(569,523.62)
4030 Sentinel Lighting Energy Sales	(1,405.14)		(1,405.14)
4035 General Energy Sales	(78,115,247.61)		(78,115,247.61)
4062 Billed WMS	(4,923,599.96)		(4,923,599.96)
4066 Billed NW	(8,217,712.85)		(8,217,712.85)
4068 Billed CN	(6,038,759.85)		(6,038,759.85)
4075 Billed - LV	(535,008.93)		(535,008.93)
4076 Billed SME Charge	(375,434.48)		(375,434.48)
4080 Distribution Services Revenue	(30,515,032.93)		(30,515,032.93)
4082 Retail Services Revenue	(38,661.60)		(38,661.60)
4084 Service Transaction Requests (STR) Revenues	(585.50)		(585.50)
4086 SSS Admin Charge	(160,439.85)		(160,439.85)
4215 Other Utility Operating Income	(19,293.92)		(19,293.92)
4225 Late Payment Charges	(336,173.09)		(336,173.09)
4235 Miscellaneous Service Revenues	(1,659,526.07)	(460,155.41)	(2,119,681.48)

	Filed RRR excluding FMV entry	Adjustments for FMV entry presentation on FS	Audited Financial Statement December 2019
4355 Gain on Disposition of Utility and Other Property	(265.49)		(265.49)
4360 Loss on Disposition of Utility and Other Property	68,274.80		68,274.80
4362 Loss on Retirement of Utility and Other Property	6,135.26		6,135.26
4375 Revenues from Non-Utility Operations	(1,604,938.35)		(1,604,938.35)
4380 Expenses from Non-Utility Operations	1,604,938.35		1,604,938.35
4390 Miscellaneous Non-Operating Income	(34,166.00)		(34,166.00)
4405 Interest and Dividend Income	(311,867.81)	86,812.51	(225,055.30)
4705 Power Purchased	61,169,795.48	(1,982,327.49)	59,187,467.99
4707 Global adjustment purchased	65,098,292.06		65,098,292.06
4708 Charges -WMS	4,923,599.96		4,923,599.96
4714 Charges -NW	8,217,712.85		8,217,712.85
4716 Charges -CN	6,038,759.85		6,038,759.85
4750 Charges - LV	535,008.93		535,008.93
4751 Charges - SME	375,434.48		375,434.48
5005 Operation Supervision and Engineering	990,133.31		990,133.31
5010 Load Dispatching	9,123.75		9,123.75
5012 Station Buildings and fixtures expense	147,870.00		147,870.00
5014 Transformer Station Equipment - Operation Labour	45,103.86		45,103.86
5015 Transformer Station Equipment - Operation	163,497.75		163,497.75
5020 Overhead Distribution Lines and Feeders -Labour	293,751.30		293,751.30
5025 Overhead Distribution Lines and Feeders - Operation expenses	107,226.32	100,295.18	207,521.50
5040 Underground Distribution Lines and Feeders Labour	199,189.56		199,189.56
5045 Underground Distribution Lines and Feeders - expenses	379,342.57		379,342.57
5055 Underground Distribution Transformers - Operation	0.00		0.00
5065 Meter Expense	397,351.34		397,351.34
5070 Customer Premises - Operation Labour	131,731.60		131,731.60
5085 Miscellaneous Distribution Expenses	2,121,355.75		2,121,355.75
5105 Maintenance Supervision and Engineering	457,769.37		457,769.37
5112 Maintenance of Transformer Station Equipment	3,949.71		3,949.71
5114 Maintenance of Distribution Station Equipment	22,933.12		22,933.12
5120 Maintenance of Poles, Towers and Fixtures	117,003.24		117,003.24
5125 Maintenance of Overhead Conductors and Devices	914,429.03		914,429.03
5130 Maintenance of Overhead Services	271,956.28		271,956.28
5135 Overhead Distribution Lines and Feeders - Right of Way	371,116.35		371,116.35
5145 Maintenance of Underground Conduit	39,289.46		39,289.46
5150 Maintenance of Underground Conductors & Devices	220,252.95		220,252.95
5155 Maintenance of Underground Services	177,100.80		177,100.80
5160 Maintenance of Line Transformers	82,773.18		82,773.18
5175 Maintenance of Meters	0.00		0.00
5305 Supervision	1,209,734.14		1,209,734.14
5310 Meter Reading Expense	586,734.21	121,501.25	708,235.46
5315 Customer Billing	3,147,231.13		3,147,231.13
5320 Collecting	441,420.21		441,420.21
5325 Collecting - Cash Over and Short	(182.52)		(182.52)
5335 Bad Debt Expense	343,782.55		343,782.55
5340 Miscellaneous Customer Accounts Expense	237,356.49	80,162.52	317,519.01
5405 Supervision	0.00		0.00
5410 Community Relations - Sundry	133,275.75		133,275.75
5605 Executive Salaries and Expenses	526,832.92		526,832.92
5610 Management Salaries and Expenses	2,501,907.09	98,270.57	2,600,177.66
5615 General Administrative Salaries and Expenses	523,112.47		523,112.47
5620 Office Supplies and Expenses	84,413.76		84,413.76
5630 Outside Services Employed	53,000.04		53,000.04
5635 Property Insurance	304,314.97		304,314.97
5655 Regulatory Expenses	267,824.34		267,824.34
5665 Miscellaneous General Expense	79,372.59		79,372.59
5675 Maintenance of General Plant	710,523.30		710,523.30
5705 Amortization Expense - Property Plant and Equipment	7,818,837.47		7,818,837.47
5715 Amortization of Intangibles and Other Electric	0.00	1,046,674.50	1,046,674.50
6005 Interest on Long Term Debt	1,799,900.41		1,799,900.41
6030 Interest on Debt to Associated Companies	712,461.89		712,461.89
6035 Other Interest Expense	240,891.93	(79,298.80)	161,593.13
6105 Taxes other that Income Taxes	228,722.39		228,722.39

	Filed RRR excluding FMV entry	Adjustments for FMV entry presentation on FS	Audited Financial Statement December 2019
6110 Income Taxes	(353,819.07)		(353,819.07)
6115 Provision for Future Income Taxes	1,294,774.63	(368,637.00)	926,137.63
6205 Donations	74,036.00		74,036.00
Net movement in regulatory balances, net of tax	0.00	(233,787.98)	(233,787.98)
Income Statement total	**(2,370,892.51)**	**1,046,673.68**	**(1,324,218.83)**

Trial Balance Summary			
Revenues	(179,360,205.81)	2,263,820.93	(177,096,384.88)
Expenses	176,989,313.30	(1,217,147.25)	175,772,166.05
(Profit)/Loss	(2,370,892.51)	1,046,673.68	(1,324,218.83)
Net Assets	366,549,339.90	0.00	366,549,339.90
Net Liabilities and Equity	(366,549,339.90)	(0.00)	(366,549,339.90)
IS (Profit)/Loss	(2,370,892.51)	1,046,673.68	(1,324,218.83)
Balance Sheet (profit)/Loss	(2,370,892.51)	1,046,674.50	(1,324,218.01)

Niagara Peninsula Energy Inc.
FMV Bump
2.1.13

Balance Sheet

		2007 FMV entry	Entry hits Retained Earnings	2007 FMV entry summary	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1	PWU AR PWPower	(216,069.30)	216,069.30													
1	Due from PW power	1,400,000.00	(1,400,000.00)													
1	Future PILS	(5,168,552.00)	5,168,552.00													
1	Inventory	7,684.34	(7,684.34)													
	Fixed assets Total FMV Bump	45,735,559.44		45,735,559.44	45,735,559.44	45,735,559.44	45,735,559.44									
	Adjustment for PW software				-	-	(226,044.00)									
							45,509,515.44	45,509,515.44	45,509,515.44	45,509,515.44	45,509,515.44	45,509,515.44	45,509,515.44	45,509,515.44	45,509,515.44	45,509,515.44
	Accum Deprec Total FMV Bump	(24,083,153.39)		(24,083,153.39)	(24,083,153.39)	(25,239,221.08)	(26,348,210.08)	(27,355,968)	(28,442,637)	(29,580,061)	(30,712,338)	(31,811,977)	(32,900,837)	(33,985,381)	(35,029,360)	(36,093,164)
	Adjustment for PW software						226,044									
	Current year depreciation				(1,156,068)	(1,108,989)	(1,233,802)	(1,086,669)	(1,137,424)	(1,132,277)	(1,099,638)	(1,088,860)	(1,084,545)	(1,043,979.19)	(1,063,803.81)	(1,046,674.50)
					(25,239,221)	(26,348,210)	(27,355,968)	(28,442,637)	(29,580,061)	(30,712,338)	(31,811,977)	(32,900,837)	(33,985,381)	(35,029,360)	(36,093,164)	(37,139,839)
	Contributed Surplus	(18,753,902.09)		(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)
1	Retained Earnings	1,078,433.00	(1,078,433.00)	-												
sum of 1's	Retained Earnings net adjustment		(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)
	Cummulative impact on RE				1,156,068	2,265,057	3,498,859	3,498,859	4,585,528	5,722,952	6,855,229	7,954,867	9,043,727	10,128,272	11,172,251	12,236,055
	for Depreciation FMV bump				(1,742,436.27)	(633,447.27)	600,354.73	600,354.73	1,687,024.02	2,824,448.02	3,956,724.83	5,056,363.23	6,145,223.41	7,229,767.93	8,273,746.94	9,337,550.75
	Depreciation expense to be closed to Cummulative impact on RE				1,156,068	1,108,989	1,233,802	1,086,669	1,137,424	1,132,277	1,099,638	1,088,860	1,084,544	1,043,979	1,063,804	1,046,675
	Net	(0.00)	-	-	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	-	-	-	(0.00)	(0.00)	(0.00)	(0.00)

Income Statement

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Depreciation expense FMV bump	1,156,068	1,111,638	1,233,802	1,086,669	1,137,424	1,132,277	1,099,638	1,088,860	1,084,545	1,043,979	1,063,804	1,046,675
Adjust depreciation expense FMV bump	0	-2649	0	0	0							
	1,156,068	1,108,989	1,233,802	1,086,669	1,137,424	1,132,277	1,099,638	1,088,860	1,084,545	1,043,979	1,063,804	1,046,675

Niagara Peninsula Energy Inc.
For the Twelve Months Ending December 31, 2018

RRR Part 1
Trial Balance Mapped to Financial Statement Grouping
2.1.13

	RRR = Financial Statements December 2018	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry presentation on FS	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
1005 Cash	8,815,365.30				8,815,365.30		
1010 Cash Advance and Working Funds	2,573.64	8,817,938.94			2,573.64	8,817,938.94	
1100 Custom Accounts Receivable	12,861,381.11				12,861,381.11		
1104 Accounts Receivable - Recoverable Work	737,568.08				737,568.08		
1110 Other Accounts Receivable	1,214,673.92				1,214,673.92		
1130 Accumulated Provision for Uncollectible Accts	(623,246.00)	14,190,377.11			(623,246.00)	14,190,377.11	
1120 Accrued Utility Revenues	13,917,403.46	13,917,403.46			13,917,403.46	13,917,403.46	
1200 Accounts Receivable from Associated Companies	12,230.84	12,230.84			12,230.84	12,230.84	
2294 Accrual for Taxes,"Payments in Lieu"of Taxes	472,515.50	472,515.50		0.00	472,515.50	472,515.50	
1180 Prepayments	1,225,260.27				1,225,260.27		
1606 Organization	0.00	1,225,260.27		1,926.45	1,926.45	1,227,186.72	
1330 Plant Materials and Operating Supplies	1,411,916.72	1,411,916.72	40,047,642.84		1,411,916.72	1,411,916.72	40,049,569.29
1606 Organization	1,926.45			(1,926.45)	0.00		
1705 Land	82,347.02				82,347.02		
1708 Buildings and Fixtures	3,779,709.96				3,779,709.96		
1715 Station Equipment	2,848,447.52				2,848,447.52		
1735 Underground Conduit	1,090.59				1,090.59		
1740 Underground Conductors and Devices	138,793.40				138,793.40		
1805 Land	424,925.77				424,925.77		
1612 Land Rights	1,604,396.58				1,604,396.58		
1808 Buildings and Fixtures	111,638.13				111,638.13		
1815 Transformer Station Equipment - Normally Primary	77,002.22				77,002.22		
1820 Distribution Station Equipment - Normally Primary	6,969,921.26				6,969,921.26		
1830 Poles, Towers and Fixtures	54,165,897.91				54,165,897.91		
1835 Overhead Conductors and Devices	39,044,434.20				39,044,434.20		
1840 Underground Conduit	14,270,567.32				14,270,567.32		
1845 Underground Conductors and Devices	81,757,368.70			685,283.51	82,442,652.21		
1850 Line Transformers	45,206,419.38			228,427.84	45,434,847.22		
1855 Services	11,110,940.70				11,110,940.70		
1860 Meters	11,886,464.66				11,886,464.66		
1865 Other Installations on Customer's Premises	439.87				439.87		
1875 Street Lighting and Signal Systems	21,835.21				21,835.21		
1905 Land	508,969.83				508,969.83		
1908 Buildings and Fixtures	18,679,787.18				18,679,787.18		
1915 Office Furniture and Equipment	1,856,958.78				1,856,958.78		
1920 Computer Equipment-Hardware	5,202,742.69				5,202,742.69		
1930 Transportation Equipment	9,762,133.29				9,762,133.29		
1935 Stores Equipment	328,494.50				328,494.50		
1940 Tools, Shop and Garage Equipment	2,355,709.72				2,355,709.72		
1945 Measurement and Testing Equipment	204,006.18				204,006.18		
1955 Communication Equipment	1,470,680.08				1,470,680.08		
1960 Miscellaneous Equipment	72,951.31				72,951.31		
1980 System Supervisory Equipment	128,960.64				128,960.64		
2005 Property Under Capital Leases	143,036.00				143,036.00		
2060 Electric Plant Acquisition Adjustment	142,276.60				142,276.60		
2065 Other Electric Plant Adjustment	0.00			44,542,460.70	44,542,460.70		
2105 Accumulated Amortization of Electric Utility-Plant	(146,357,213.11)				(146,357,213.11)		
2140 Accumulated Amortization of Electric Plant	(142,276.60)				(142,276.60)		
2160 Accumulated Amortization of Other Utility Plant	0.00	167,861,783.94	167,861,783.94	(36,093,162.89)	(36,093,162.89)	177,222,866.65	
1910 Leasehold Improvements	120,252.32				120,252.32		
1611 Computer Software	4,754,578.22				4,754,578.22		
2120 Accumulated Amortization of Electric Utility Plant-Intangibles	(5,169,768.26)	(294,937.72)	(294,937.72)	967,054.74	(4,202,713.52)	672,117.02	
1495 Other Assets and Deferred Charges	15,052,139.77	15,052,139.77	15,052,139.77	(5,731,417.77)	9,320,722.00	9,320,722.00	187,215,705.67
1508 Other Regulatory Assets	(690,007.24)			885,546.07	195,538.83		
1495 Deferred Taxes-Non-current assets	0.00			5,731,417.77	5,731,417.77		

	RRR = Financial Statements December 2018	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry presentation on FS	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
1550 Hydro One Low Voltage Variance	1,655,693.86				1,655,693.86		
1555 Smart Meter Capital and Recovery Variance	0.00				0.00		
1584 RSVA - NW	191,221.25				191,221.25		
1586 RSVA - CN	131,615.55				131,615.55		
1588 RSVA - Power	1,273,793.94				1,273,793.94		
1589 RSVA - GA Non-RPP	0.00				0.00		
1518 RCVA - Retail	92,290.80				92,290.80		
1548 RCVA - STR	311,972.71				311,972.71		
1568 LRAM variance	0.00				0.00		
1535 Smart Grid Deferral Account	0.00				0.00		
1595 Disposition and Recovery of Regulatory Balances	0.00	2,966,580.87	2,966,580.87	6,198.10	6,198.10	9,589,742.81	9,589,742.81
2205 Accounts Payable	(7,479,120.68)				(7,479,120.68)		
2250 Debt Retirement Charges DRC payable	0.00				0.00		
2256 Independent Market Operator Fees and Penalties	(8,953,669.53)				(8,953,669.53)		
2290 Commodity Taxes	1,201,339.02				1,201,339.02		
2292 Payroll Deductions/Expenses Payable	(1,244.33)	(15,232,695.52)			(1,244.33)	(15,232,695.52)	
2210 Current portion of customer deposits	(1,230,368.97)				(1,230,368.97)		
2320 Other Miscellaneous Non-current liabilities	(37,334.17)	(1,267,703.14)			(37,334.17)	(1,267,703.14)	
2220 Miscellaneous Current and Accrued Liabilities	0.00				0.00		
2425 Other Deferred Credits	(941,207.75)	(941,207.75)			(941,207.75)	(941,207.75)	
2294 Accrual for Taxes,"Payments in Lieu"of Taxes	0.00	0.00		0.00	0.00	0.00	
2210 Current portion of Customer deposits	0.00	0.00			0.00	0.00	
2240 Accounts Payable to Associated Companies	0.00	0.00			0.00	0.00	
2260 Current Portion of Long Term Debt	(11,123,823.39)	(11,123,823.39)	(28,565,429.80)		(11,123,823.39)	(11,123,823.39)	(28,565,429.80)
2520 Other Long Term debt	0.00				0.00		
2525 Term Bank Loans-long term Portion	(40,337,500.00)				(40,337,500.00)		
2550 Advances from Associated Companies	(25,605,089.72)	(65,942,589.72)			(25,605,089.72)	(65,942,589.72)	
2335 Long Term Customer Deposits	0.00	0.00			0.00		
2310 Vested Sick Leave Liability	(66,461.32)	(66,461.32)			(66,461.32)	(66,461.32)	
2306 Employee Future Benefits	(4,020,821.00)	(4,020,821.00)			(4,020,821.00)	(4,020,821.00)	
1995 Contributions and Grants - Credit	(26,261,968.54)	(26,261,968.54)		(913,711.35)	(27,175,679.89)	(27,175,679.89)	
2350 Future Income Tax - non current	(11,403,207.19)	(11,403,207.19)	(107,695,047.77)		(11,403,207.19)	(11,403,207.19)	(108,608,759.12)
2405 Other Regulatory liabilities	(1,518,825.50)				(1,518,825.50)		
1508 Other Regulatory Assets - OPEB	(74.60)			(885,546.07)	(885,620.67)		
1551 Smart Metering Entity Variance	(39,114.58)				(39,114.58)		
1555 Smart Meter Capital and Recovery Variance	(24,682.86)				(24,682.86)		
1576 Accounting Changes Under CGAAP	(168,380.51)				(168,380.51)		
1580 RSVA - WMS	(1,616,043.55)				(1,616,043.55)		
1582 RSVA - One Time	0.00				0.00		
1586 RSVA - CN	0.00				0.00		
1588 RSVA - Power	0.00				0.00		
1589 RSVA - GA Non-RPP	(145,228.01)				(145,228.01)		
1562 Deferred Payments in Lieu of taxes	0.00				0.00		
1563 Deferred PILS contra Account	0.00				0.00		
1557 Mist meter variance	(38,173.47)				(38,173.47)		
1521 Special Purpose Charge	0.00				0.00		
1595 Disposition and Recovery of Regulatory Balances	(2,200,144.78)	(5,750,667.86)	(5,750,667.86)	(6,198.10)	(2,206,342.88)	(6,642,412.03)	(6,642,412.03)
3005 Common Shares Issued	(31,245,882.02)	(31,245,882.02)			(31,245,882.02)	(31,245,882.02)	
3010 Contributed Surplus	0.00			(18,753,902.09)	(18,753,902.09)		
3047 Appropriations of Retained Earnings - current	(6,705,305.00)	(6,705,305.00)			(6,705,305.00)	(25,459,207.09)	
3040 Appropriated Retained Earnings	(42,657,182.99)			8,273,745.73	(34,383,437.26)		
3041 Appropriated Retained Earnings							
3046 Balance Transferred from Income	(4,413,694.26)			1,063,803.81	(3,349,890.45)		
3049 Dividends payable - Common Shares	1,400,000.00	(45,670,877.25)	(83,622,064.27)		1,400,000.00	(36,333,327.71)	(93,038,416.82)
Balance Sheet	**0.00**	**0.00**	**0.00**	**(0.00)**	**0.00**	**0.00**	**0.00**
4006 Residential Energy Sales	(33,307,583.08)			3,016,697.41	(30,290,885.67)		

	RRR = Financial Statements December 2018	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry presentation on FS	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
4010 Commercial Energy Sales	(12,536,775.80)				(12,536,775.80)		
4025 Streetlighting energy sales	(513,162.45)				(513,162.45)		
4030 Sentinel Lighting Energy Sales	(26,278.55)				(26,278.55)		
4035 General Energy Sales	(71,005,089.54)				(71,005,089.54)		
4062 Billed WMS	(4,974,222.48)				(4,974,222.48)		
4066 Billed NW	(8,270,652.86)				(8,270,652.86)		
4068 Billed CN	(5,980,545.99)				(5,980,545.99)		
4075 Billed - LV	(539,772.51)				(539,772.51)		
4076 Billed SME Charge	(372,641.38)	(137,526,724.64)	(137,526,724.64)		(372,641.38)	(134,510,027.23)	(134,510,027.23)
4080 Distribution Services Revenue	(30,080,101.75)				(30,080,101.75)		
4082 Retail Services Revenue	(26,297.60)				(26,297.60)		
4084 Service Transaction Requests (STR) Revenues	(348.25)				(348.25)		
4086 SSS Admin Charge	(158,073.44)	(30,264,821.04)	(30,264,821.04)		(158,073.44)	(30,264,821.04)	(30,264,821.04)
4215 Other Utility Operating Income	(28,867.35)				(28,867.35)		
4225 Late Payment Charges	(372,405.41)				(372,405.41)		
4235 Miscellaneous Service Revenues	(1,576,385.84)			(394,229.07)	(1,970,614.91)		
4355 Gain on Disposition of Utility and Other Property	(5,152.74)				(5,152.74)		
4360 Loss on Disposition of Utility and Other Property	73,229.54				73,229.54		
4362 Loss on Retirement of Utility and Other Property	28,012.99				28,012.99		
4375 Revenues from Non-Utility Operations	(2,739,666.60)				(2,739,666.60)		
4380 Expenses from Non-Utility Operations	2,302,136.78				2,302,136.78		
4390 Miscellaneous Non-Operating Income	(38,875.00)	(2,357,973.63)	(2,357,973.63)		(38,875.00)	(2,752,202.70)	(2,752,202.70)
4705 Power Purchased	65,058,587.34			628,728.67	65,687,316.01		
4707 Global adjustment purchased	52,330,302.08				52,330,302.08		
4708 Charges -WMS	4,974,222.48				4,974,222.48		
4714 Charges -NW	8,270,652.86				8,270,652.86		
4716 Charges -CN	5,980,545.99				5,980,545.99		
4751 Charges -SME	539,772.51				539,772.51		
4750 Charges - LV	372,641.38	137,526,724.64	137,526,724.64		372,641.38	138,155,453.31	138,155,453.31
5005 Operation Supervision and Engineering	883,891.94				883,891.94		
5010 Load Dispatching	13,286.75				13,286.75		
5012 Station Buildings and fixtures expense	99,329.41				99,329.41		
5014 Transformer Station Equipment - Operation Labour	12,172.64				12,172.64		
5015 Transformer Station Equipment - Operation	156,255.02				156,255.02		
5020 Overhead Distribution Lines and Feeders -Labour	337,499.66				337,499.66		
5025 Overhead Distribution Lines and Feeders - Operation expenses	84,196.93			394,229.07	478,426.00		
5040 Underground Distribution Lines and Feeders Labour	119,802.25				119,802.25		
5045 Underground Distribution Lines and Feeders - expenses	360,803.91				360,803.91		
5055 Underground Distribution Transformer - Operations	0.00				0.00		
5065 Meter Expense	487,590.62				487,590.62		
5085 Miscellaneous Distribution Expenses	1,747,444.49				1,747,444.49		
5105 Maintenance Supervision and Engineering	472,897.35				472,897.35		
5112 Maintenance of Transformer Station Equipment	0.00				0.00		
5114 Maintenance of Distribution Station Equipment	41,546.32				41,546.32		
5120 Maintenance of Poles, Towers and Fixtures	121,039.75				121,039.75		
5125 Maintenance of Overhead Conductors and Devices	806,530.30				806,530.30		
5130 Maintenance of Overhead Services	241,563.45				241,563.45		
5135 Overhead Distribution Lines and Feeders - Right of Way	346,945.05				346,945.05		
5145 Maintenance of Underground Conduit	18,986.99				18,986.99		
5150 Maintenance of Underground Conductors & Devices	257,377.92				257,377.92		
5155 Maintenance of Underground Services	194,158.68				194,158.68		
5160 Maintenance of Line Transformers	88,066.14				88,066.14		
5175 Maintenance of Meters	0.00	6,891,385.57			0.00	7,285,614.64	7,285,614.64
5070 Customer Premises - Operation Labour	156,013.81				156,013.81		
5405 Supervision	0.00				0.00		
5410 Community Relations - Sundry	132,561.33	288,575.14			132,561.33	288,575.14	288,575.14
5305 Supervision	1,249,335.91				1,249,335.91		
5310 Meter Reading Expense	502,043.63			50,830.50	552,874.13		
5315 Customer Billing	2,928,066.19				2,928,066.19		
5320 Collecting	502,451.80				502,451.80		
5325 Collecting - Cash Over and Short	87.33				87.33		

	RRR = Financial Statements December 2018	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry presentation on FS	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
5335 Bad Debt Expense	308,528.48				308,528.48		
5340 Miscellaneous Customer Accounts Expense	226,767.81	5,717,281.15		92,092.95	318,860.76	5,860,204.60	5,860,204.60
5605 Executive Salaries and Expenses	449,088.22				449,088.22		
5610 Management Salaries and Expenses	2,248,166.75				2,248,166.75		
5615 General Administrative Salaries and Expenses	533,578.19			51,637.00	585,215.19		
5620 Office Supplies and Expenses	77,217.93				77,217.93		
5630 Outside Services Employed	50,004.00				50,004.00		
5635 Property Insurance	325,583.83				325,583.83		
5655 Regulatory Expenses	281,798.41				281,798.41		
5665 Miscellaneous General Expense	80,603.44				80,603.44		
5675 Maintenance of General Plant	766,513.45				766,513.45		
6105 Taxes other that Income Taxes	237,392.16				237,392.16		
6205 Donations	73,406.50	5,123,352.88			73,406.50	5,174,989.88	5,174,989.88
5705 Amortization Expense - Property Plant and Equipment	7,449,738.89	7,449,738.89		0.00	7,449,738.89	7,449,738.89	7,449,738.89
5715 Amortization of Intangibles and Other Electric	0.00	0.00		1,063,803.81	1,063,803.81	1,063,803.81	1,063,803.81
4405 Interest and Dividend Income	(357,053.48)	(357,053.48)		96,798.83	(260,254.65)	(260,254.65)	(260,254.65)
6005 Interest on Long Term Debt	1,450,363.09				1,450,363.09		
6030 Interest on Debt to Associated Companies	1,221,362.76				1,221,362.76		
6035 Other Interest Expense	179,293.91	2,851,019.76	27,964,299.91	(163,306.38)	15,987.53	2,687,713.38	2,687,713.38
6215 Penalties	0.00				0.00		
6110 Income Taxes	(179,925.17)				(179,925.17)	(179,925.17)	(179,925.17)
6115 Provision for Future Income Taxes	424,725.67	244,800.50	244,800.50	715,431.52	1,140,157.19	1,140,157.19	1,140,157.19
Net Income for the year	**(4,413,694.26)**	**(4,413,694.26)**	**(4,413,694.26)**	**5,552,714.31**	**1,139,020.05**	**1,139,020.05**	**1,139,020.05**
Net movement in regulatory balances, net of tax	0.00	0.00	0.00	(4,488,910.50)	(4,488,910.50)	(4,488,910.50)	(4,488,910.50)
Net income, net movement in regulatory balances	**(4,413,694.26)**	**(4,413,694.26)**	**(4,413,694.26)**	**1,063,803.81**	**(3,349,890.45)**	**(3,349,890.45)**	**(3,349,890.45)**
Other Comprehensive Income							
Remeasurements of post-employment benefits	0.00			0.00	0.00	0.00	0.00
Net movement in regulatory balances, net of tax	0.00			0.00	0.00	0.00	0.00
Other Comprehensive Income for the year	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Comprehensive income for the year	**(4,413,694.26)**	**(4,413,694.26)**	**(4,413,694.26)**	**1,063,803.81**	**(3,349,890.45)**	**(3,349,890.45)**	**(3,349,890.45)**
Trial Balance Summary							
Revenues	(170,149,519.31)	(170,149,519.31)	(170,149,519.31)	(1,866,442.16)	(172,015,961.47)	(172,015,961.47)	(172,015,961.47)
Expenses	165,735,825.05	165,735,825.05	165,735,825.05	2,930,245.97	168,666,071.02	168,666,071.02	168,666,071.02
(Profit)/Loss	(4,413,694.26)	(4,413,694.26)	(4,413,694.26)	1,063,803.81	(3,349,890.45)	(3,349,890.45)	(3,349,890.45)
Net Assets	194,666,883.30	193,148,057.80	219,882,541.84	9,416,352.55	204,083,235.85	202,564,410.35	230,212,605.74
Net Liabilities and Equity	(194,666,883.30)	(193,148,057.80)	(219,882,541.84)	(9,416,352.55)	(204,083,235.85)	(202,564,410.35)	(230,212,605.74)
IS (Profit)/Loss	(4,413,694.26)	(4,413,694.26)	(4,413,694.26)	1,063,803.81	(3,349,890.45)	(3,349,890.45)	(3,349,890.45)
Balance Sheet (profit)/Loss	(4,413,694.26)	(4,413,694.26)	(4,413,694.26)	1,063,803.81	(3,349,890.45)	(3,349,890.45)	(3,349,890.45)
	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Niagara Peninsula Energy Inc.
For the Twelve Months Ending December 31, 2018
RRR Part 2
Trial Balance by Account
2.1.13

	Filed RRR excluding FMV entry	Adjustments for FMV entry presentation on FS	Audited Financial Statement December 2018
Current Assets			
1005 Cash	8,815,365.30		8,815,365.30
1010 Cash Advance and Working Funds	2,573.64		2,573.64
1100 Custom Accounts Receivable	12,861,381.11		12,861,381.11
1104 Accounts Receivable - Recoverable Work	737,568.08		737,568.08
1110 Other Accounts Receivable	1,214,673.92		1,214,673.92
1120 Accrued Utility Revenues	13,917,403.46		13,917,403.46
1130 Accumulated Provision for Uncollectible Accts	(623,246.00)		(623,246.00)
1180 Prepayments	1,225,260.27		1,225,260.27
1200 Accounts Receivable from Associated Companies	12,230.84		12,230.84
1330 Plant Materials and Operating Supplies	1,411,916.72		1,411,916.72
1495 Other Assets and Deferred Charges	15,052,139.77		15,052,139.77
1508 Other Regulatory Assets-Lead/Lag Study	(690,007.24)		(690,007.24)
1508 Other Regulatory Assets Incremental Capital Charges Hydro One	0.00		0.00
1508 Other Regulatory Assets - OPEB	0.00		0.00
1518 RCVA - Retail	92,290.80		92,290.80
1522 OPEB Forecast vs Actual Differential	(74.60)		(74.60)
1548 RCVA - STR	311,972.71		311,972.71
1550 Hydro One Low Voltage Variance	1,655,693.86		1,655,693.86
1551 Smart Metering Entity Variance	(39,114.58)		(39,114.58)
1555 Smart Meter Capital and Recovery Variance	(24,682.86)		(24,682.86)
1557 Mist meter variance	(38,173.47)		(38,173.47)
1568 LRAM variance	0.00		0.00
1576 Accounting Changes Under CGAAP	(168,380.51)		(168,380.51)
1580 RSVA - WMS	(1,616,043.55)		(1,616,043.55)
1584 RSVA - NW	191,221.25		191,221.25
1586 RSVA - CN	131,615.55		131,615.55
1588 RSVA - Power	1,273,793.94		1,273,793.94
1589 RSVA - GA Non-RPP	(145,228.01)		(145,228.01)
1595 Disposition and Recovery of Regulatory Balances	(2,200,144.78)		(2,200,144.78)
1606 Organization	1,926.45		1,926.45
1611 Computer Software	4,754,578.22		4,754,578.22
1612 Land Rights	1,604,396.58		1,604,396.58
1705 Land	82,347.02		82,347.02
1708 Buildings and Fixtures	3,779,709.96		3,779,709.96
1715 Station Equipment	2,848,447.52		2,848,447.52
1735 Underground Conduit	1,090.59		1,090.59
1740 Underground Conductors and Devices	138,793.40		138,793.40
1805 Land	424,925.77		424,925.77
1808 Buildings and Fixtures	111,638.13		111,638.13
1815 Transformer Station Equipment - Normally Primary	77,002.22		77,002.22
1820 Distribution Station Equipment - Normally Primary	6,969,921.26		6,969,921.26
1830 Poles, Towers and Fixtures	54,165,897.91		54,165,897.91
1835 Overhead Conductors and Devices	39,044,434.20		39,044,434.20
1840 Underground Conduit	14,270,567.32		14,270,567.32
1845 Underground Conductors and Devices	81,757,368.70	685,283.51	82,442,652.21
1850 Line Transformers	45,206,419.38	228,427.84	45,434,847.22
1855 Services	11,110,940.70		11,110,940.70
1860 Meters	11,886,464.66		11,886,464.66
1865 Other Installations on Customer's Premises	439.87		439.87
1875 Street Lighting and Signal Systems	21,835.21		21,835.21
1905 Land	508,969.83		508,969.83
1908 Buildings and Fixtures	18,679,787.18		18,679,787.18
1910 Leasehold Improvements	120,252.32		120,252.32
1915 Office Furniture and Equipment	1,856,958.78		1,856,958.78

	Filed RRR excluding FMV entry	Adjustments for FMV entry presentation on FS	Audited Financial Statement December 2018
1920 Computer Equipment-Hardware	5,202,742.69		5,202,742.69
1930 Transportation Equipment	9,762,133.29		9,762,133.29
1935 Stores Equipment	328,494.50		328,494.50
1940 Tools, Shop and Garage Equipment	2,355,709.72		2,355,709.72
1945 Measurement and Testing Equipment	204,006.18		204,006.18
1955 Communication Equipment	1,470,680.08		1,470,680.08
1960 Miscellaneous Equipment	72,951.31		72,951.31
1980 System Supervisory Equipment	128,960.64		128,960.64
1995 Contributions and Grants - Credit	(26,261,968.54)	(913,711.35)	(27,175,679.89)
2005 Property Under Capital Leases	143,036.00		143,036.00
2060 Electric Plant Acquisition Adjustment	142,276.60		142,276.60
2065 Other Electric Plant Adjustment	0.00	45,509,515.44	45,509,515.44
2105 Accumulated Amortization of Electric Utility-Plant	(146,357,213.11)		(146,357,213.11)
2120 Accumulated Amortization of Electric Utility Plant-Intangibles	(5,169,768.26)		(5,169,768.26)
2140 Accumulated Amortization of Electric Plant	(142,276.60)		(142,276.60)
2160 Accumulated Amortization of Other Utility Plant	0.00	(36,093,162.89)	(36,093,162.89)
2205 Accounts Payable	(7,479,120.68)		(7,479,120.68)
2256 Independent Market Operator Fees and Penalties	(8,953,669.53)		(8,953,669.53)
2210 Current portion of Customer deposits	(1,230,368.97)		(1,230,368.97)
2240 Accounts Payable to Associated Companies	0.00		0.00
2250 Debt Retirement Charges DRC payable	0.00		0.00
2260 Current Portion of Long Term Debt	(11,123,823.39)		(11,123,823.39)
2290 Commodity Taxes	1,201,339.02		1,201,339.02
2292 Payroll Deductions/Expenses Payable	(1,244.33)		(1,244.33)
2294 Accrual for Taxes,"Payments in Lieu"of Taxes	472,515.50		472,515.50
2296 Future Income Taxes - Current	0.00		0.00
2306 Employee Future Benefits	(4,020,821.00)		(4,020,821.00)
2310 Vested Sick Leave Liability	(66,461.32)		(66,461.32)
2320 Other Miscellaneous Non-current liabilities	(37,334.17)		(37,334.17)
2350 Future Income Tax - Non Current	(11,403,207.19)		(11,403,207.19)
2405 Other Regulatory Liabilities	(1,518,825.50)		(1,518,825.50)
2425 Other Deferred Credits	(941,207.75)		(941,207.75)
2525 Term Bank Loans-long term Portion	(40,337,500.00)		(40,337,500.00)
2550 Advances from Associated Companies	(25,605,089.72)		(25,605,089.72)
3005 Common Shares Issued	(31,245,882.02)		(31,245,882.02)
3010 Contributed Surplus	0.00	(18,753,902.09)	(18,753,902.09)
3040 Appropriated Retained Earnings	(42,657,182.99)	8,273,745.73	(34,383,437.26)
3046 Balance Transferred from Income	(4,413,694.26)	1,063,803.81	(3,349,890.45)
3047 Appropriations of Retained Earnings - current	(6,705,305.00)		(6,705,305.00)
3049 Dividends payable - Common Shares	1,400,000.00		1,400,000.00
Balance Sheet	(0.00)	(0.00)	0.00

4006 Residential Energy Sales	(33,307,583.08)	3,016,697.41	(30,290,885.67)
4010 Commercial Energy Sales	(12,536,775.80)		(12,536,775.80)
4025 Streetlighting energy sales	(513,162.45)		(513,162.45)
4030 Sentinel Lighting Energy Sales	(26,278.55)		(26,278.55)
4035 General Energy Sales	(71,005,089.54)		(71,005,089.54)
4062 Billed WMS	(4,974,222.48)		(4,974,222.48)
4066 Billed NW	(8,270,652.86)		(8,270,652.86)
4068 Billed CN	(5,980,545.99)		(5,980,545.99)
4075 Billed - LV	(539,772.51)		(539,772.51)
4076 Billed SME Charge	(372,641.38)		(372,641.38)
4080 Distribution Services Revenue	(30,080,101.75)		(30,080,101.75)
4082 Retail Services Revenue	(26,297.60)		(26,297.60)
4084 Service Transaction Requests (STR) Revenues	(348.25)		(348.25)
4086 SSS Admin Charge	(158,073.44)		(158,073.44)
4215 Other Utility Operating Income	(28,867.35)		(28,867.35)
4225 Late Payment Charges	(372,405.41)		(372,405.41)
4235 Miscellaneous Service Revenues	(1,576,385.84)		(1,576,385.84)
4355 Gain on Disposition of Utility and Other Property	(5,152.74)		(5,152.74)

	Filed RRR excluding FMV entry	Adjustments for FMV entry presentation on FS	Audited Financial Statement December 2018
4360 Loss on Disposition of Utility and Other Property	73,229.54		73,229.54
4362 Loss on Retirement of Utility and Other Property	28,012.99		28,012.99
4375 Revenues from Non-Utility Operations	(2,739,666.60)		(2,739,666.60)
4380 Expenses from Non-Utility Operations	2,302,136.78		2,302,136.78
4390 Miscellaneous Non-Operating Income	(38,875.00)		(38,875.00)
4405 Interest and Dividend Income	(357,053.48)	96,798.83	(260,254.65)
4705 Power Purchased	65,058,587.34	628,728.67	65,687,316.01
4707 Global adjustment purchased	52,330,302.08		52,330,302.08
4708 Charges -WMS	4,974,222.48		4,974,222.48
4714 Charges -NW	8,270,652.86		8,270,652.86
4716 Charges -CN	5,980,545.99		5,980,545.99
4750 Charges - LV	539,772.51		539,772.51
4751 Charges - SME	372,641.38		372,641.38
5005 Operation Supervision and Engineering	883,891.94		883,891.94
5010 Load Dispatching	13,286.75		13,286.75
5012 Station Buildings and fixtures expense	99,329.41		99,329.41
5014 Transformer Station Equipment - Operation Labour	12,172.64		12,172.64
5015 Transformer Station Equipment - Operation	156,255.02		156,255.02
5020 Overhead Distribution Lines and Feeders -Labour	337,499.66		337,499.66
5025 Overhead Distribution Lines and Feeders - Operation expenses	84,196.93		84,196.93
5040 Underground Distribution Lines and Feeders Labour	119,802.25		119,802.25
5045 Underground Distribution Lines and Feeders - expenses	360,803.91		360,803.91
5055 Underground Distribution Transformers - Operation	0.00		0.00
5065 Meter Expense	487,590.62		487,590.62
5070 Customer Premises - Operation Labour	156,013.81		156,013.81
5085 Miscellaneous Distribution Expenses	1,747,444.49		1,747,444.49
5105 Maintenance Supervision and Engineering	472,897.35		472,897.35
5112 Maintenance of Transformer Station Equipment	0.00		0.00
5114 Maintenance of Distribution Station Equipment	41,546.32		41,546.32
5120 Maintenance of Poles, Towers and Fixtures	121,039.75		121,039.75
5125 Maintenance of Overhead Conductors and Devices	806,530.30		806,530.30
5130 Maintenance of Overhead Services	241,563.45		241,563.45
5135 Overhead Distribution Lines and Feeders - Right of Way	346,945.05		346,945.05
5145 Maintenance of Underground Conduit	18,986.99		18,986.99
5150 Maintenance of Underground Conductors & Devices	257,377.92		257,377.92
5155 Maintenance of Underground Services	194,158.68		194,158.68
5160 Maintenance of Line Transformers	88,066.14		88,066.14
5175 Maintenance of Meters	0.00		0.00
5305 Supervision	1,249,335.91		1,249,335.91
5310 Meter Reading Expense	502,043.63	50,830.50	552,874.13
5315 Customer Billing	2,928,066.19		2,928,066.19
5320 Collecting	502,451.80		502,451.80
5325 Collecting - Cash Over and Short	87.33		87.33
5335 Bad Debt Expense	308,528.48		308,528.48
5340 Miscellaneous Customer Accounts Expense	226,767.81	92,092.95	318,860.76
5405 Supervision	0.00		0.00
5410 Community Relations - Sundry	132,561.33		132,561.33
5605 Executive Salaries and Expenses	449,088.22		449,088.22
5610 Management Salaries and Expenses	2,248,166.75	51,637.00	2,299,803.75
5615 General Administrative Salaries and Expenses	533,578.19		533,578.19
5620 Office Supplies and Expenses	77,217.93		77,217.93
5630 Outside Services Employed	50,004.00		50,004.00
5635 Property Insurance	325,583.83		325,583.83
5655 Regulatory Expenses	281,798.41		281,798.41
5665 Miscellaneous General Expense	80,603.44		80,603.44
5675 Maintenance of General Plant	766,513.45		766,513.45
5705 Amortization Expense - Property Plant and Equipment	7,449,738.89		7,449,738.89
5715 Amortization of Intangibles and Other Electric	0.00	1,063,803.81	1,063,803.81
6005 Interest on Long Term Debt	1,450,363.09		1,450,363.09
6030 Interest on Debt to Associated Companies	1,221,362.76		1,221,362.76
6035 Other Interest Expense	179,293.91	(163,306.38)	15,987.53
6105 Taxes other that Income Taxes	237,392.16		237,392.16
6110 Income Taxes	(179,925.17)		(179,925.17)

	Filed RRR excluding FMV entry	Adjustments for FMV entry presentation on FS	Audited Financial Statement December 2018
6115 Provision for Future Income Taxes	424,725.67	715,431.52	1,140,157.19
6205 Donations	73,406.50		73,406.50
Net movement in regulatory balances, net of tax	0.00	(4,488,910.50)	(4,488,910.50)
Income Statement total	**(4,413,694.26)**	**1,063,803.81**	**(3,349,890.45)**

Trial Balance Summary			
Revenues	(170,506,572.79)	3,113,496.24	(167,393,076.55)
Expenses	166,092,878.53	(2,049,692.43)	164,043,186.10
(Profit)/Loss	(4,413,694.26)	1,063,803.81	(3,349,890.45)
Net Assets	346,050,828.67	0.00	346,050,828.67
Net Liabilities and Equity	(346,050,828.67)	(0.00)	(346,050,828.67)
IS (Profit)/Loss	(4,413,694.26)	1,063,803.81	(3,349,890.45)
Balance Sheet (profit)/Loss	(4,413,694.26)	1,063,803.81	(3,349,890.45)

Niagara Peninsula Energy Inc.
FMV Bump
2.1.13

Balance Sheet

		2007 FMV entry	Entry hits Retained Earnings	2007 FMV entry summary	2015	2016	2017	2018
1	PWU AR PWPower	(216,069.30)	216,069.30					
1	Due from PW power	1,400,000.00	(1,400,000.00)					
1	Future PILS	(5,168,552.00)	5,168,552.00					
1	Inventory	7,684.34	(7,684.34)					
	Fixed assets Total FMV Bump	45,735,559.44		45,735,559.44				
	Adjustment for PW software							
					45,509,515.44	45,509,515.44	45,509,515.44	45,509,515.44
	Accum Deprec Total FMV Bump	(24,083,153.39)		(24,083,153.39)	(31,811,977)	(32,900,837)	(33,985,381)	(35,029,360)
	Adjustment for PW software							
	Current year depreciation				(1,088,860)	(1,084,545)	(1,043,979.19)	(1,063,803.81)
					(32,900,837)	(33,985,381)	(35,029,360)	(36,093,164)
	Contributed Surplus	(18,753,902.09)		(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)
1	Retained Earnings	1,078,433.00	(1,078,433.00)	-				
sum of 1's	Retained Earnings net adjustment		(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)
	Cummulative impact on RE				7,954,867	9,043,727	10,128,272	11,172,251
	for Depreciation FMV bump				5,056,363.23	6,145,223.41	7,229,767.93	8,273,746.94
	Depreciation expense to be closed to Cummulative impact on RE				1,088,860	1,084,544	1,043,979	1,063,804
	Net	(0.00)	-	-	-	(0.00)	(0.00)	(0.00)

Income Statement

	2015	2016	2017	2018
Depreciation expense FMV bump	1,088,860	1,084,545	1,043,979	1,063,804
Adjust depreciation expense FMV bump				
	1,088,860	1,084,545	1,043,979	1,063,804

Niagara Peninsula Energy Inc.
For the Twelve Months Ending December 31, 2017

RRR Part 1
Trial Balance Mapped to Financial Statement Grouping
2.1.13

	RRR = Financial Statements December 2017	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry presentation on FS	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
1005 Cash	20,729,492.14				20,729,492.14		
1010 Cash Advance and Working Funds	2,183.39	20,731,675.53			2,183.39	20,731,675.53	
1100 Custom Accounts Receivable	9,694,243.49				9,694,243.49		
1104 Accounts Receivable - Recoverable Work	475,087.45				475,087.45		
1110 Other Accounts Receivable	1,534,003.27				1,534,003.27		
1130 Accumulated Provision for Uncollectible Accts	(559,111.12)	11,144,223.09			(559,111.12)	11,144,223.09	
1120 Accrued Utility Revenues	15,682,703.45	15,682,703.45			15,682,703.45	15,682,703.45	
1200 Accounts Receivable from Associated Companies	8,229.11	8,229.11			8,229.11	8,229.11	
2294 Accrual for Taxes,"Payments in Lieu"of Taxes	1,356,520.51	1,356,520.51			1,356,520.51	1,356,520.51	
1180 Prepayments	994,680.56				994,680.56		
1606 Organization	0.00	994,680.56		1,926.45	1,926.45	996,607.01	
1330 Plant Materials and Operating Supplies	1,555,751.66	1,555,751.66	51,473,783.91		1,555,751.66	1,555,751.66	51,475,710.36
1606 Organization	1,926.45			(1,926.45)	0.00		
1705 Land	82,347.02				82,347.02		
1708 Buildings and Fixtures	3,693,130.15				3,693,130.15		
1715 Station Equipment	2,799,739.08				2,799,739.08		
1735 Underground Conduit	1,090.59				1,090.59		
1740 Underground Conductors and Devices	138,793.40				138,793.40		
1805 Land	424,925.77				424,925.77		
1612 Land Rights	1,604,396.58				1,604,396.58		
1808 Buildings and Fixtures	111,638.13				111,638.13		
1815 Transformer Station Equipment - Normally Primary	77,002.22				77,002.22		
1820 Distribution Station Equipment - Normally Primary	7,105,405.48				7,105,405.48		
1830 Poles, Towers and Fixtures	52,181,536.95				52,181,536.95		
1835 Overhead Conductors and Devices	36,694,265.50				36,694,265.50		
1840 Underground Conduit	13,214,099.65				13,214,099.65		
1845 Underground Conductors and Devices	79,554,220.83			676,166.27	80,230,387.10		
1850 Line Transformers	43,412,600.97			225,388.76	43,637,989.73		
1855 Services	9,793,962.94				9,793,962.94		
1860 Meters	10,982,456.16				10,982,456.16		
1865 Other Installations on Customer's Premises	439.87				439.87		
1875 Street Lighting and Signal Systems	21,835.21				21,835.21		
1905 Land	508,969.83				508,969.83		
1908 Buildings and Fixtures	17,654,922.96				17,654,922.96		
1915 Office Furniture and Equipment	1,741,870.55				1,741,870.55		
1920 Computer Equipment-Hardware	4,879,232.10				4,879,232.10		
1930 Transportation Equipment	9,666,389.75				9,666,389.75		
1935 Stores Equipment	323,279.08				323,279.08		
1940 Tools, Shop and Garage Equipment	2,289,677.93				2,289,677.93		
1945 Measurement and Testing Equipment	204,006.18				204,006.18		
1955 Communication Equipment	1,360,854.58				1,360,854.58		
1960 Miscellaneous Equipment	72,951.31				72,951.31		
1980 System Supervisory Equipment	128,960.64				128,960.64		
2005 Property Under Capital Leases	143,036.00				143,036.00		
2060 Electric Plant Acquisition Adjustment	142,276.60				142,276.60		
2065 Other Electric Plant Adjustment	0.00			44,542,460.74	44,542,460.74		
2105 Accumulated Amortization of Electric Utility-Plant	(140,627,112.79)				(140,627,112.79)		
2140 Accumulated Amortization of Electric Plant	(142,276.60)				(142,276.60)		
2160 Accumulated Amortization of Other Utility Plant	0.00	160,242,851.07	160,242,851.07	(35,029,359.21)	(35,029,359.21)	170,655,581.18	
1910 Leasehold Improvements	120,252.32				120,252.32		
1611 Computer Software	4,465,687.43				4,465,687.43		
2120 Accumulated Amortization of Electric Utility Plant-Intangibles	(4,684,714.45)	(98,774.70)	(98,774.70)	967,054.70	(3,717,659.75)	868,280.00	
1495 Other Assets and Deferred Charges	14,078,764.75	14,078,764.75	14,078,764.75	(4,758,043.75)	9,320,721.00	9,320,721.00	180,844,582.18
1508 Other Regulatory Assets	(718,698.00)			857,421.00	138,723.00		
1495 Deferred Taxes-Non-current assets	0.00			4,758,043.75	4,758,043.75		

	RRR = Financial Statements December 2017	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry presentation on FS	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
1550 Hydro One Low Voltage Variance	2,138,048.09				2,138,048.09		
1555 Smart Meter Capital and Recovery Variance	(24,682.86)				(24,682.86)		
1584 RSVA - NW	331,324.97				331,324.97		
1589 RSVA - GA Non-RPP	1,188,386.29				1,188,386.29		
1518 RCVA - Retail	73,189.57				73,189.57		
1548 RCVA - STR	238,980.99				238,980.99		
1568 LRAM variance	0.00				0.00		
1535 Smart Grid Deferral Account	0.00				0.00		
1595 Disposition and Recovery of Regulatory Balances	0.00	3,226,549.05	3,226,549.05	334,328.23	334,328.23	9,176,342.03	9,176,342.03
2205 Accounts Payable	(20,863,854.63)				(20,863,854.63)		
2250 Debt Retirement Charges DRC payable	(459,406.22)				(459,406.22)		
2290 Commodity Taxes	1,521,484.41				1,521,484.41		
2292 Payroll Deductions/Expenses Payable	(1,355.49)	(19,803,131.93)			(1,355.49)	(19,803,131.93)	
2210 Current portion of customer deposits	(996,397.59)				(996,397.59)		
2320 Other Miscellaneous Non-current liabilities	(37,334.17)	(1,033,731.76)			(37,334.17)	(1,033,731.76)	
2220 Miscellaneous Current and Accrued Liabilities	0.00				0.00		
2425 Other Deferred Credits	(533,189.79)	(533,189.79)			(533,189.79)	(533,189.79)	
2210 Current portion of Customer deposits	0.00	0.00			0.00	0.00	
2240 Accounts Payable to Associated Companies	0.00	0.00			0.00	0.00	
2260 Current Portion of Long Term Debt	(11,513,893.50)	(11,513,893.50)	(32,883,946.98)		(11,513,893.50)	(11,513,893.50)	(32,883,946.98)
2520 Other Long Term debt	0.00				0.00		
2525 Term Bank Loans-long term Portion	(41,461,323.40)				(41,461,323.40)		
2550 Advances from Associated Companies	(25,605,089.72)	(67,066,413.12)			(25,605,089.72)	(67,066,413.12)	
2335 Long Term Customer Deposits	0.00	0.00			0.00		
2310 Vested Sick Leave Liability	(61,727.41)	(61,727.41)			(61,727.41)	(61,727.41)	
2306 Employee Future Benefits	(3,883,400.00)	(3,883,400.00)			(3,883,400.00)	(3,883,400.00)	
1995 Contributions and Grants - Credit	(24,630,094.91)	(24,630,094.91)		(901,555.03)	(25,531,649.94)	(25,531,649.94)	
2350 Future Income Tax - non current	(10,263,050.00)	(10,263,050.00)	(105,904,685.44)		(10,263,050.00)	(10,263,050.00)	(106,806,240.47)
2405 Other Regulatory liabilities	(1,260,882.00)				(1,260,882.00)		
1508 Other Regulatory Assets - OPEB	0.00			(857,421.00)	(857,421.00)		
1551 Smart Metering Entity Variance	(59,046.39)				(59,046.39)		
1576 Accounting Changes Under CGAAP	(175,110.79)				(175,110.79)		
1580 RSVA - WMS	(5,433,685.25)				(5,433,685.25)		
1582 RSVA - One Time	0.00				0.00		
1586 RSVA - CN	(870,741.94)				(870,741.94)		
1588 RSVA - Power	(1,742,301.15)				(1,742,301.15)		
1562 Deferred Payments in Lieu of taxes	0.00				0.00		
1563 Deferred PILS contra Account	0.00				0.00		
1557 Mist meter variance	(87,796.02)				(87,796.02)		
1521 Special Purpose Charge	0.00				0.00		
1595 Disposition and Recovery of Regulatory Balances	103,392.02	(9,526,171.52)	(9,526,171.52)	(334,328.23)	(230,936.21)	(10,717,920.75)	(10,717,920.75)
3005 Common Shares Issued	(31,245,882.02)	(31,245,882.02)			(31,245,882.02)	(31,245,882.02)	
3010 Contributed Surplus	0.00			(18,753,902.09)	(18,753,902.09)		
3047 Appropriations of Retained Earnings - current	(6,705,305.00)	(6,705,305.00)			(6,705,305.00)	(25,459,207.09)	
3040 Appropriated Retained Earnings	(41,091,540.13)			7,229,766.67	(33,861,773.46)		
3041 Appropriated Retained Earnings							
3046 Balance Transferred from Income	(2,965,642.99)			1,043,979.19	(1,921,663.80)		
3049 Dividends payable - Common Shares	1,400,000.00	(42,657,183.12)	(80,608,370.14)		1,400,000.00	(34,383,437.26)	(91,088,526.37)
Balance Sheet	**0.00**	**0.00**	**0.00**	**(0.00)**	**0.00**	**0.00**	**0.00**

4006 Residential Energy Sales	(38,836,795.96)				(38,836,795.96)		
4010 Commercial Energy Sales	(13,777,710.63)				(13,777,710.63)		
4025 Streetlighting energy sales	(520,258.79)				(520,258.79)		
4030 Sentinel Lighting Energy Sales	(9,779.27)				(9,779.27)		
4035 General Energy Sales	(72,552,643.93)				(72,552,643.93)		
4062 Billed WMS	(6,279,802.09)				(6,279,802.09)		
4066 Billed NW	(7,956,810.73)				(7,956,810.73)		

	RRR = Financial Statements December 2017	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry presentation on FS	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
4068 Billed CN	(5,469,934.34)				(5,469,934.34)		
4075 Billed - LV	(514,301.20)				(514,301.20)		
4076 Billed SME Charge	(508,479.71)	(146,426,516.65)	(146,426,516.65)		(508,479.71)	(146,426,516.65)	(146,426,516.65)
4080 Distribution Services Revenue	(29,185,423.85)			650,367.00	(28,535,056.85)		
4082 Retail Services Revenue	(30,252.80)				(30,252.80)		
4084 Service Transaction Requests (STR) Revenues	(368.00)				(368.00)		
4086 SSS Admin Charge	(156,050.21)	(29,372,094.86)	(29,372,094.86)		(156,050.21)	(28,721,727.86)	(28,721,727.86)
4215 Other Utility Operating Income	(29,140.73)				(29,140.73)		
4225 Late Payment Charges	(372,953.63)				(372,953.63)		
4235 Miscellaneous Service Revenues	(1,574,465.37)				(1,574,465.37)		
4355 Gain on Disposition of Utility and Other Property	(7,522.21)				(7,522.21)		
4360 Loss on Disposition of Utility and Other Property	2,047.85				2,047.85		
4362 Loss on Retirement of Utility and Other Property	100,430.97				100,430.97		
4375 Revenues from Non-Utility Operations	(3,314,050.91)				(3,314,050.91)		
4380 Expenses from Non-Utility Operations	3,320,281.42				3,320,281.42		
4390 Miscellaneous Non-Operating Income	(63,464.00)	(1,938,836.61)	(1,938,836.61)		(63,464.00)	(1,938,836.61)	(1,938,836.61)
4705 Power Purchased	65,298,861.72			962,084.49	66,260,946.21		
4707 Global adjustment purchased	60,398,326.86				60,398,326.86		
4708 Charges -WMS	6,279,802.09				6,279,802.09		
4714 Charges -NW	7,956,810.73				7,956,810.73		
4716 Charges -CN	5,469,934.34				5,469,934.34		
4751 Charges -SME	514,301.20				514,301.20		
4750 Charges - LV	508,479.71	146,426,516.65	146,426,516.65		508,479.71	147,388,601.14	147,388,601.14
5005 Operation Supervision and Engineering	1,155,764.48				1,155,764.48		
5010 Load Dispatching	11,452.60				11,452.60		
5012 Station Buildings and fixtures expense	58,773.04				58,773.04		
5014 Transformer Station Equipment - Operation Labour	8,539.00				8,539.00		
5015 Transformer Station Equipment - Operation	118,016.13				118,016.13		
5020 Overhead Distribution Lines and Feeders -Labour	239,264.66				239,264.66		
5025 Overhead Distribution Lines and Feeders - Operation expenses	5,441.89				5,441.89		
5040 Underground Distribution Lines and Feeders Labour	120,416.18				120,416.18		
5045 Underground Distribution Lines and Feeders - expenses	386,096.12				386,096.12		
5055 Underground Distribution Transformer - Operations	0.00				0.00		
5065 Meter Expense	441,267.79				441,267.79		
5085 Miscellaneous Distribution Expenses	2,086,266.99				2,086,266.99		
5105 Maintenance Supervision and Engineering	440,959.63				440,959.63		
5112 Maintenance of Transformer Station Equipment	0.00				0.00		
5114 Maintenance of Distribution Station Equipment	27,993.18				27,993.18		
5120 Maintenance of Poles, Towers and Fixtures	98,912.28				98,912.28		
5125 Maintenance of Overhead Conductors and Devices	889,307.41				889,307.41		
5130 Maintenance of Overhead Services	198,772.21				198,772.21		
5135 Overhead Distribution Lines and Feeders - Right of Way	416,951.47				416,951.47		
5145 Maintenance of Underground Conduit	56,823.72				56,823.72		
5150 Maintenance of Underground Conductors & Devices	228,399.86				228,399.86		
5155 Maintenance of Underground Services	175,846.20				175,846.20		
5160 Maintenance of Line Transformers	123,450.39				123,450.39		
5175 Maintenance of Meters	2,819.92	7,291,535.15			2,819.92	7,291,535.15	7,291,535.15
5070 Customer Premises - Operation Labour	100,855.26				100,855.26		
5405 Supervision	2,773.33				2,773.33		
5410 Community Relations - Sundry	158,480.02	262,108.61			158,480.02	262,108.61	262,108.61
5305 Supervision	1,054,996.45				1,054,996.45		
5310 Meter Reading Expense	485,582.28			(3,028.50)	482,553.78		
5315 Customer Billing	3,069,622.34				3,069,622.34		
5320 Collecting	512,413.63				512,413.63		
5325 Collecting - Cash Over and Short	(13.18)				(13.18)		
5335 Bad Debt Expense	263,168.46				263,168.46		
5340 Miscellaneous Customer Accounts Expense	234,487.15	5,620,257.13		88,805.42	323,292.57	5,706,034.05	5,706,034.05
5605 Executive Salaries and Expenses	425,640.06				425,640.06		
5610 Management Salaries and Expenses	2,307,039.24				2,307,039.24		
5615 General Administrative Salaries and Expenses	521,483.38			66,209.00	587,692.38		
5620 Office Supplies and Expenses	90,853.81				90,853.81		

	RRR = Financial Statements December 2017	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry presentation on FS	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
5630 Outside Services Employed	58,950.04				58,950.04		
5635 Property Insurance	335,956.55				335,956.55		
5655 Regulatory Expenses	306,084.08				306,084.08		
5665 Miscellaneous General Expense	83,824.41				83,824.41		
5675 Maintenance of General Plant	650,790.61				650,790.61		
6105 Taxes other that Income Taxes	240,498.78				240,498.78		
6205 Donations	73,416.00	5,094,536.96			73,416.00	5,160,745.96	5,160,745.96
5705 Amortization Expense - Property Plant and Equipment	6,937,287.03	6,937,287.03		0.00	6,937,287.03	6,937,287.03	6,937,287.03
5715 Amortization of Intangibles and Other Electric	0.00	0.00		1,043,979.19	1,043,979.19	1,043,979.19	1,043,979.19
4405 Interest and Dividend Income	(278,532.59)	(278,532.59)		53,419.26	(225,113.33)	(225,113.33)	(225,113.33)
6005 Interest on Long Term Debt	1,504,869.16				1,504,869.16		
6030 Interest on Debt to Associated Companies	1,221,362.76				1,221,362.76		
6035 Other Interest Expense	134,075.27	2,860,307.19	27,787,499.48	(122,996.08)	11,079.19	2,737,311.11	2,737,311.11
6215 Penalties	0.00				0.00		
6110 Income Taxes	325,010.00				325,010.00		
6115 Provision for Future Income Taxes	232,779.00	557,789.00	557,789.00	951,064.00	1,183,843.00	1,508,853.00	1,508,853.00
Net Income for the year	**(2,965,642.99)**	**(2,965,642.99)**	**(2,965,642.99)**	**3,689,903.78**	**724,260.79**	**724,260.79**	**724,260.79**
Net movement in regulatory balances, net of tax	0.00	0.00	0.00	(2,645,924.59)	(2,645,924.59)	(2,645,924.59)	(2,645,924.59)
Net income, net movement in regulatory balances	**(2,965,642.99)**	**(2,965,642.99)**	**(2,965,642.99)**	**1,043,979.19**	**(1,921,663.80)**	**(1,921,663.80)**	**(1,921,663.80)**
Other Comprehensive Income							
Remeasurements of post-employment benefits	0.00			524,202.00	524,202.00	524,202.00	524,202.00
Net movement in regulatory balances, net of tax	0.00			(524,202.00)	(524,202.00)	(524,202.00)	(524,202.00)
Other Comprehensive Income for the year	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Comprehensive income for the year	**(2,965,642.99)**	**(2,965,642.99)**	**(2,965,642.99)**	**1,043,979.19**	**(1,921,663.80)**	**(1,921,663.80)**	**(1,921,663.80)**
Trial Balance Summary							
Revenues	(177,737,448.12)	(177,737,448.12)	(177,737,448.12)	(1,995,557.59)	(179,733,005.71)	(179,733,005.71)	(179,733,005.71)
Expenses	174,771,805.13	174,771,805.13	174,771,805.13	3,039,536.78	177,811,341.91	177,811,341.91	177,811,341.91
(Profit)/Loss	(2,965,642.99)	(2,965,642.99)	(2,965,642.99)	1,043,979.19	(1,921,663.80)	(1,921,663.80)	(1,921,663.80)
Net Assets	194,671,269.14	193,410,387.14	219,397,002.56	10,480,156.23	205,151,425.37	203,890,543.37	230,778,713.82
Net Liabilities and Equity	(194,671,269.14)	(193,410,387.14)	(219,397,002.56)	(10,480,156.23)	(205,151,425.37)	(203,890,543.37)	(230,778,713.82)
IS (Profit)/Loss	(2,965,642.99)	(2,965,642.99)	(2,965,642.99)	1,043,979.19	(1,921,663.80)	(1,921,663.80)	(1,921,663.80)
Balance Sheet (profit)/Loss	(2,965,642.99)	(2,965,642.99)	(2,965,642.99)	1,043,979.19	(1,921,663.80)	(1,921,663.80)	(1,921,663.80)
	(0.00)	(0.00)	(0.00)	0.00	(0.00)	(0.00)	(0.00)

Niagara Peninsula Energy Inc.
For the Twelve Months Ending December 31, 2017
RRR Part 2
Trial Balance by Account
2.1.13

	Filed RRR excluding FMV entry	Adjustments for FMV entry presentation on FS	Audited Financial Statement December 2017
Current Assets			
1005 Cash	20,729,492.14		20,729,492.14
1010 Cash Advance and Working Funds	2,183.39		2,183.39
1100 Custom Accounts Receivable	9,694,243.49		9,694,243.49
1104 Accounts Receivable - Recoverable Work	475,087.45		475,087.45
1110 Other Accounts Receivable	1,534,003.27		1,534,003.27
1120 Accrued Utility Revenues	15,682,703.45		15,682,703.45
1130 Accumulated Provision for Uncollectible Accts	(559,111.12)		(559,111.12)
1180 Prepayments	994,680.56		994,680.56
1200 Accounts Receivable from Associated Companies	8,229.11		8,229.11
1330 Plant Materials and Operating Supplies	1,555,751.66		1,555,751.66
1495 Other Assets and Deferred Charges	14,078,764.75		14,078,764.75
1508 Other Regulatory Assets-Lead/Lag Study	(718,698.00)	852,935.77	134,237.77
1508 Other Regulatory Assets Incremental Capital Charges Hydro One	0.00	4,485.23	4,485.23
1508 Other Regulatory Assets - OPEB	0.00	(857,421.00)	(857,421.00)
1518 RCVA - Retail	73,189.57		73,189.57
1548 RCVA - STR	238,980.99		238,980.99
1550 Hydro One Low Voltage Variance	2,138,048.09		2,138,048.09
1551 Smart Metering Entity Variance	(59,046.39)		(59,046.39)
1555 Smart Meter Capital and Recovery Variance	(24,682.86)		(24,682.86)
1557 Mist meter variance	(87,796.02)		(87,796.02)
1568 LRAM variance	0.00		0.00
1576 Accounting Changes Under CGAAP	(175,110.79)		(175,110.79)
1580 RSVA - WMS	(5,433,685.25)		(5,433,685.25)
1584 RSVA - NW	331,324.97		331,324.97
1586 RSVA - CN	(870,741.94)		(870,741.94)
1588 RSVA - Power	(1,742,301.15)		(1,742,301.15)
1589 RSVA - GA Non-RPP	1,188,386.29		1,188,386.29
1595 Disposition and Recovery of Regulatory Balances	103,392.02		103,392.02
1606 Organization	1,926.45		1,926.45
1611 Computer Software	4,465,687.43		4,465,687.43
1612 Land Rights	1,604,396.58		1,604,396.58
1705 Land	82,347.02		82,347.02
1708 Buildings and Fixtures	3,693,130.15		3,693,130.15
1715 Station Equipment	2,799,739.08		2,799,739.08
1735 Underground Conduit	1,090.59		1,090.59
1740 Underground Conductors and Devices	138,793.40		138,793.40
1805 Land	424,925.77		424,925.77
1808 Buildings and Fixtures	111,638.13		111,638.13
1815 Transformer Station Equipment - Normally Primary	77,002.22		77,002.22
1820 Distribution Station Equipment - Normally Primary	7,105,405.48		7,105,405.48
1830 Poles, Towers and Fixtures	52,181,536.95		52,181,536.95
1835 Overhead Conductors and Devices	36,694,265.50		36,694,265.50
1840 Underground Conduit	13,214,099.65		13,214,099.65
1845 Underground Conductors and Devices	79,554,220.83	676,166.27	80,230,387.10
1850 Line Transformers	43,412,600.97	225,388.76	43,637,989.73
1855 Services	9,793,962.94		9,793,962.94
1860 Meters	10,982,456.16		10,982,456.16
1865 Other Installations on Customer's Premises	439.87		439.87
1875 Street Lighting and Signal Systems	21,835.21		21,835.21
1905 Land	508,969.83		508,969.83
1908 Buildings and Fixtures	17,654,922.96		17,654,922.96
1910 Leasehold Improvements	120,252.32		120,252.32
1915 Office Furniture and Equipment	1,741,870.55		1,741,870.55
1920 Computer Equipment-Hardware	4,879,232.10		4,879,232.10

	Filed RRR excluding FMV entry	Adjustments for FMV entry presentation on FS	Audited Financial Statement December 2017
1930 Transportation Equipment	9,666,389.75		9,666,389.75
1935 Stores Equipment	323,279.08		323,279.08
1940 Tools, Shop and Garage Equipment	2,289,677.93		2,289,677.93
1945 Measurement and Testing Equipment	204,006.18		204,006.18
1955 Communication Equipment	1,360,854.58		1,360,854.58
1960 Miscellaneous Equipment	72,951.31		72,951.31
1980 System Supervisory Equipment	128,960.64		128,960.64
1995 Contributions and Grants - Credit	(24,630,094.91)	(901,555.03)	(25,531,649.94)
2005 Property Under Capital Leases	143,036.00		143,036.00
2060 Electric Plant Acquisition Adjustment	142,276.60		142,276.60
2065 Other Electric Plant Adjustment	0.00	45,509,515.44	45,509,515.44
2105 Accumulated Amortization of Electric Utility-Plant	(140,627,112.79)		(140,627,112.79)
2120 Accumulated Amortization of Electric Utility Plant-Intangibles	(4,684,714.45)		(4,684,714.45)
2140 Accumulated Amortization of Electric Plant	(142,276.60)		(142,276.60)
2160 Accumulated Amortization of Other Utility Plant	0.00	(35,029,359.21)	(35,029,359.21)
2205 Accounts Payable	(20,863,854.63)		(20,863,854.63)
2210 Current portion of Customer deposits	(996,397.59)		(996,397.59)
2240 Accounts Payable to Associated Companies	0.00		0.00
2250 Debt Retirement Charges DRC payable	(459,406.22)		(459,406.22)
2260 Current Portion of Long Term Debt	(11,513,893.50)		(11,513,893.50)
2290 Commodity Taxes	1,521,484.41		1,521,484.41
2292 Payroll Deductions/Expenses Payable	(1,355.49)		(1,355.49)
2294 Accrual for Taxes,"Payments in Lieu"of Taxes	1,356,520.51		1,356,520.51
2296 Future Income Taxes - Current	0.00		0.00
2306 Employee Future Benefits	(3,883,400.00)		(3,883,400.00)
2310 Vested Sick Leave Liability	(61,727.41)		(61,727.41)
2320 Other Miscellaneous Non-current liabilities	(37,334.17)		(37,334.17)
2350 Future Income Tax - Non Current	(10,263,050.00)		(10,263,050.00)
2405 Other Regulatory Liabilities	(1,260,882.00)		(1,260,882.00)
2425 Other Deferred Credits	(533,189.79)		(533,189.79)
2525 Term Bank Loans-long term Portion	(41,461,323.40)		(41,461,323.40)
2550 Advances from Associated Companies	(25,605,089.72)		(25,605,089.72)
3005 Common Shares Issued	(31,245,882.02)		(31,245,882.02)
3010 Contributed Surplus	0.00	(18,753,902.09)	(18,753,902.09)
3040 Appropriated Retained Earnings	(41,091,540.13)	7,229,766.67	(33,861,773.46)
3046 Balance Transferred from Income	(2,965,642.99)	1,043,979.19	(1,921,663.80)
3047 Appropriations of Retained Earnings - current	(6,705,305.00)		(6,705,305.00)
3049 Dividends payable - Common Shares	1,400,000.00		1,400,000.00
Balance Sheet	(0.00)	(0.00)	0.00

4006 Residential Energy Sales	(38,836,795.96)		(38,836,795.96)
4010 Commercial Energy Sales	(13,777,710.63)		(13,777,710.63)
4025 Streetlighting energy sales	(520,258.79)		(520,258.79)
4030 Sentinel Lighting Energy Sales	(9,779.27)		(9,779.27)
4035 General Energy Sales	(72,552,643.93)		(72,552,643.93)
4062 Billed WMS	(6,279,802.09)		(6,279,802.09)
4066 Billed NW	(7,956,810.73)		(7,956,810.73)
4068 Billed CN	(5,469,934.34)		(5,469,934.34)
4075 Billed - LV	(514,301.20)		(514,301.20)
4076 Billed SME Charge	(508,479.71)		(508,479.71)
4080 Distribution Services Revenue	(29,185,423.85)	650,367.00	(28,535,056.85)
4082 Retail Services Revenue	(30,252.80)		(30,252.80)
4084 Service Transaction Requests (STR) Revenues	(368.00)		(368.00)
4086 SSS Admin Charge	(156,050.21)		(156,050.21)
4215 Other Utility Operating Income	(29,140.73)		(29,140.73)
4225 Late Payment Charges	(372,953.63)		(372,953.63)
4235 Miscellaneous Service Revenues	(1,574,465.37)		(1,574,465.37)
4355 Gain on Disposition of Utility and Other Property	(7,522.21)		(7,522.21)
4360 Loss on Disposition of Utility and Other Property	2,047.85		2,047.85
4362 Loss on Retirement of Utility and Other Property	100,430.97		100,430.97

	Filed RRR excluding FMV entry	Adjustments for FMV entry presentation on FS	Audited Financial Statement December 2017
4375 Revenues from Non-Utility Operations	(3,314,050.91)		(3,314,050.91)
4380 Expenses from Non-Utility Operations	3,320,281.42		3,320,281.42
4390 Miscellaneous Non-Operating Income	(63,464.00)		(63,464.00)
4405 Interest and Dividend Income	(278,532.59)	53,419.26	(225,113.33)
4705 Power Purchased	65,298,861.72	962,084.49	66,260,946.21
4707 Global adjustment purchased	60,398,326.86		60,398,326.86
4708 Charges -WMS	6,279,802.09		6,279,802.09
4714 Charges -NW	7,956,810.73		7,956,810.73
4716 Charges -CN	5,469,934.34		5,469,934.34
4750 Charges - LV	514,301.20		514,301.20
4751 Charges - SME	508,479.71		508,479.71
5005 Operation Supervision and Engineering	1,155,764.48		1,155,764.48
5010 Load Dispatching	11,452.60		11,452.60
5012 Station Buildings and fixtures expense	58,773.04		58,773.04
5014 Transformer Station Equipment - Operation Labour	8,539.00		8,539.00
5015 Transformer Station Equipment - Operation	118,016.13		118,016.13
5020 Overhead Distribution Lines and Feeders -Labour	239,264.66		239,264.66
5025 Overhead Distribution Lines and Feeders - Operation expenses	5,441.89		5,441.89
5040 Underground Distribution Lines and Feeders Labour	120,416.18		120,416.18
5045 Underground Distribution Lines and Feeders - expenses	386,096.12		386,096.12
5055 Underground Distribution Transformers - Operation	0.00		0.00
5065 Meter Expense	441,267.79		441,267.79
5070 Customer Premises - Operation Labour	100,855.26		100,855.26
5085 Miscellaneous Distribution Expenses	2,086,266.99		2,086,266.99
5105 Maintenance Supervision and Engineering	440,959.63		440,959.63
5112 Maintenance of Transformer Station Equipment	0.00		0.00
5114 Maintenance of Distribution Station Equipment	27,993.18		27,993.18
5120 Maintenance of Poles, Towers and Fixtures	98,912.28		98,912.28
5125 Maintenance of Overhead Conductors and Devices	889,307.41		889,307.41
5130 Maintenance of Overhead Services	198,772.21		198,772.21
5135 Overhead Distribution Lines and Feeders - Right of Way	416,951.47		416,951.47
5145 Maintenance of Underground Conduit	56,823.72		56,823.72
5150 Maintenance of Underground Conductors & Devices	228,399.86		228,399.86
5155 Maintenance of Underground Services	175,846.20		175,846.20
5160 Maintenance of Line Transformers	123,450.39		123,450.39
5175 Maintenance of Meters	2,819.92		2,819.92
5305 Supervision	1,054,996.45		1,054,996.45
5310 Meter Reading Expense	485,582.28	(3,028.50)	482,553.78
5315 Customer Billing	3,069,622.34		3,069,622.34
5320 Collecting	512,413.63		512,413.63
5325 Collecting - Cash Over and Short	(13.18)		(13.18)
5335 Bad Debt Expense	263,168.46		263,168.46
5340 Miscellaneous Customer Accounts Expense	234,487.15	88,805.42	323,292.57
5405 Supervision	2,773.33		2,773.33
5410 Community Relations - Sundry	158,480.02		158,480.02
5605 Executive Salaries and Expenses	425,640.06		425,640.06
5610 Management Salaries and Expenses	2,307,039.24	66,209.00	2,373,248.24
5615 General Administrative Salaries and Expenses	521,483.38		521,483.38
5620 Office Supplies and Expenses	90,853.81		90,853.81
5630 Outside Services Employed	58,950.04		58,950.04
5635 Property Insurance	335,956.55		335,956.55
5655 Regulatory Expenses	306,084.08		306,084.08
5665 Miscellaneous General Expense	83,824.41		83,824.41
5675 Maintenance of General Plant	650,790.61		650,790.61
5705 Amortization Expense - Property Plant and Equipment	6,937,287.03		6,937,287.03
5715 Amortization of Intangibles and Other Electric	0.00	1,043,979.19	1,043,979.19
6005 Interest on Long Term Debt	1,504,869.16		1,504,869.16
6030 Interest on Debt to Associated Companies	1,221,362.76		1,221,362.76
6035 Other Interest Expense	134,075.27	(122,996.08)	11,079.19
6105 Taxes other that Income Taxes	240,498.78		240,498.78
6110 Income Taxes	325,010.00		325,010.00
6115 Provision for Future Income Taxes	232,779.00	951,064.00	1,183,843.00
6205 Donations	73,416.00		73,416.00

	Filed RRR excluding FMV entry	Adjustments for FMV entry presentation on FS	Audited Financial Statement December 2017
Net movement in regulatory balances, net of tax	0.00	(2,645,924.59)	(2,645,924.59)
Income Statement total	**(2,965,642.99)**	**1,043,979.19**	**(1,921,663.80)**

Trial Balance Summary			
Revenues	(178,015,980.71)	703,786.26	(177,312,194.45)
Expenses	175,050,337.72	340,192.93	175,390,530.65
(Profit)/Loss	(2,965,642.99)	1,043,979.19	(1,921,663.80)
Net Assets	339,840,060.38	0.00	339,840,060.38
Net Liabilities and Equity	(339,840,060.38)	(0.00)	(339,840,060.38)
IS (Profit)/Loss	(2,965,642.99)	1,043,979.19	(1,921,663.80)
Balance Sheet (profit)/Loss	(2,965,642.99)	1,043,979.19	(1,921,663.80)

Niagara Peninsula Energy Inc.
FMV Bump
2.1.13

Balance Sheet

		2007 FMV entry	Entry hits Retained Earnings	2007 FMV entry summary	2015	2016	2017
1	PWU AR PWPower	(216,069.30)	216,069.30				
1	Due from PW power	1,400,000.00	(1,400,000.00)				
1	Future PILS	(5,168,552.00)	5,168,552.00				
1	Inventory	7,684.34	(7,684.34)				
	Fixed assets Total FMV Bump	45,735,559.44		45,735,559.44			
	Adjustment for PW software						
					45,509,515.44	45,509,515.44	45,509,515.44
	Accum Deprec Total FMV Bump	(24,083,153.39)		(24,083,153.39)	(31,811,977)	(32,900,837)	(33,985,381)
	Adjustment for PW software						
	Current year depreciation				(1,088,860)	(1,084,545)	(1,043,979.19)
					(32,900,837)	(33,985,381)	(35,029,360)
	Contributed Surplus	(18,753,902.09)		(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)
1	Retained Earnings	1,078,433.00	(1,078,433.00)	-			
sum of 1's	Retained Earnings net adjustment		(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)
	Cummulative impact on RE				7,954,867	9,043,727	10,128,272
	for Depreciation FMV bump				5,056,363.23	6,145,223.41	7,229,767.93
	Depreciation expense to be closed to				1,088,860	1,084,544	1,043,979
	Cummulative impact on RE						
	Net	(0.00)	-	-	-	(0.00)	(0.00)

Income Statement

	2015	2016	2017
Depreciation expense FMV bump	1,088,860	1,084,545	1,043,979
Adjust depreciation expense FMV bump			
	1,088,860	1,084,545	1,043,979

Niagara Peninsula Energy Inc.
For the Twelve Months Ending December 31, 2016

RRR Part 1
Trial Balance Mapped to Financial Statement Grouping
2.1.13

	RRR = Financial Statements December 2016	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry presentation on FS	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
1005 Cash	21,561,403.67				21,561,403.67		
1010 Cash Advance and Working Funds	2,340.06	21,563,743.73			2,340.06	21,563,743.73	
1100 Custom Accounts Receivable	13,691,762.06				13,691,762.06		
1104 Accounts Receivable - Recoverable Work	668,332.20				668,332.20		
1110 Other Accounts Receivable	888,648.49				888,648.49		
1130 Accumulated Provision for Uncollectible Accts	(544,268.40)	14,704,474.35			(544,268.40)	14,704,474.35	
1120 Accrued Utility Revenues	17,220,600.80	17,220,600.80			17,220,600.80	17,220,600.80	
1200 Accounts Receivable from Associated Companies	5,981.82	5,981.82			5,981.82	5,981.82	
2294 Accrual for Taxes,"Payments in Lieu"of Taxes	1,757,969.85	1,757,969.85			1,757,969.85	1,757,969.85	
1180 Prepayments	1,109,502.97				1,109,502.97		
1606 Organization	0.00	1,109,502.97		1,926.45	1,926.45	1,111,429.42	
1330 Plant Materials and Operating Supplies	1,364,873.93	1,364,873.93	57,727,147.45		1,364,873.93	1,364,873.93	57,729,073.90
1606 Organization	1,926.45			(1,926.45)	0.00		
1705 Land	82,347.02				82,347.02		
1708 Buildings and Fixtures	3,693,130.15				3,693,130.15		
1715 Station Equipment	2,742,786.83				2,742,786.83		
1735 Underground Conduit	1,090.59				1,090.59		
1740 Underground Conductors and Devices	138,793.40				138,793.40		
1805 Land	424,925.77				424,925.77		
1612 Land Rights	1,604,396.58				1,604,396.58		
1808 Buildings and Fixtures	111,638.13				111,638.13		
1815 Transformer Station Equipment - Normally Primary	77,002.22				77,002.22		
1820 Distribution Station Equipment - Normally Primary	6,867,625.70				6,867,625.70		
1830 Poles, Towers and Fixtures	50,015,120.93				50,015,120.93		
1835 Overhead Conductors and Devices	34,575,301.36				34,575,301.36		
1840 Underground Conduit	12,338,449.27				12,338,449.27		
1845 Underground Conductors and Devices	76,896,409.72			516,338.79	77,412,748.51		
1850 Line Transformers	41,954,237.25			172,112.93	42,126,350.18		
1855 Services	8,465,324.66				8,465,324.66		
1860 Meters	10,215,217.08				10,215,217.08		
1865 Other Installations on Customer's Premises	439.87				439.87		
1875 Street Lighting and Signal Systems	21,835.21				21,835.21		
1905 Land	508,969.83				508,969.83		
1908 Buildings and Fixtures	17,251,915.94				17,251,915.94		
1915 Office Furniture and Equipment	1,723,807.92				1,723,807.92		
1920 Computer Equipment-Hardware	4,547,110.82				4,547,110.82		
1930 Transportation Equipment	9,074,201.71				9,074,201.71		
1935 Stores Equipment	323,279.08				323,279.08		
1940 Tools, Shop and Garage Equipment	2,200,663.23				2,200,663.23		
1945 Measurement and Testing Equipment	204,006.18				204,006.18		
1955 Communication Equipment	1,442,918.22				1,442,918.22		
1960 Miscellaneous Equipment	72,951.31				72,951.31		
1980 System Supervisory Equipment	128,960.64				128,960.64		
2005 Property Under Capital Leases	143,036.00				143,036.00		
2060 Electric Plant Acquisition Adjustment	142,276.60				142,276.60		
2065 Other Electric Plant Adjustment	0.00			44,599,559.80	44,599,559.80		
2105 Accumulated Amortization of Electric Utility-Plant	(134,811,126.38)				(134,811,126.38)		
2140 Accumulated Amortization of Electric Plant	(142,276.60)				(142,276.60)		
2160 Accumulated Amortization of Other Utility Plant	0.00	153,038,692.69	153,038,692.69	(33,985,380.14)	(33,985,380.14)	164,339,397.62	
1910 Leasehold Improvements	120,252.32				120,252.32		
1611 Computer Software	3,754,791.74				3,754,791.74		
2120 Accumulated Amortization of Electric Utility Plant-Intangibles	(4,327,923.70)	(452,879.64)	(452,879.64)	909,955.64	(3,417,968.06)	457,076.00	
2350 Future Income Tax - non current	52,518.00	52,518.00	52,518.00		52,518.00	52,518.00	164,848,991.62
1508 Other Regulatory Assets	(1,499,569.31)			1,570,621.00	71,051.69		
1495 Deferred Taxes-Non-current assets	3,721,217.75				3,721,217.75		

	RRR = Financial Statements December 2016	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry presentation on FS	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
1550 Hydro One Low Voltage Variance	1,281,720.45				1,281,720.45		
1584 RSVA - NW	383,007.69				383,007.69		
1589 RSVA - GA Non-RPP	1,028,719.79				1,028,719.79		
1518 RCVA - Retail	54,100.61				54,100.61		
1548 RCVA - STR	169,264.53				169,264.53		
1568 LRAM variance	495,195.15				495,195.15		
1535 Smart Grid Deferral Account	0.00				0.00		
1555 Smart Meter Capital and Recovery Variance	203,886.41				203,886.41		
1595 Disposition and Recovery of Regulatory Balances	0.00	5,837,543.07	5,837,543.07	119,153.55	119,153.55	7,527,317.62	7,527,317.62
2205 Accounts Payable	(19,482,227.66)				(19,482,227.66)		
2250 Debt Retirement Charges DRC payable	(453,311.50)				(453,311.50)		
2290 Commodity Taxes	1,499,574.07				1,499,574.07		
2292 Payroll Deductions/Expenses Payable	(1,341.49)	(18,437,306.58)			(1,341.49)	(18,437,306.58)	
2210 Current portion of customer deposits	(1,505,461.07)				(1,505,461.07)		
2320 Other Miscellaneous Non-current liabilities	(37,334.17)	(1,542,795.24)			(37,334.17)	(1,542,795.24)	
2220 Miscellaneous Current and Accrued Liabilities	0.00				0.00		
2425 Other Deferred Credits	(713,946.99)	(713,946.99)			(713,946.99)	(713,946.99)	
2210 Current portion of Customer deposits	0.00	0.00			0.00	0.00	
2240 Accounts Payable to Associated Companies	0.00	0.00			0.00	0.00	
2260 Current Portion of Long Term Debt	(11,466,354.84)	(11,466,354.84)	(32,160,403.65)		(11,466,354.84)	(11,466,354.84)	(32,160,403.65)
2520 Other Long Term debt	0.00				0.00		
2525 Term Bank Loans-long term Portion	(42,975,216.90)				(42,975,216.90)		
2550 Advances from Associated Companies	(25,605,089.72)	(68,580,306.62)			(25,605,089.72)	(68,580,306.62)	
2335 Long Term Customer Deposits	0.00	0.00			0.00		
2310 Vested Sick Leave Liability	(55,182.42)	(55,182.42)			(55,182.42)	(55,182.42)	
2306 Employee Future Benefits	(2,619,248.00)	(2,619,248.00)			(2,619,248.00)	(2,619,248.00)	
1995 Contributions and Grants - Credit	(23,195,905.23)	(23,195,905.23)		(688,451.72)	(23,884,356.95)	(23,884,356.95)	
2350 Future Income Tax - non current	0.00	0.00	(94,450,642.27)		0.00	0.00	(95,139,093.99)
2405 Other Regulatory liabilities	(986,123.00)				(986,123.00)		
1508 Other Regulatory Assets - OPEB	0.00			(1,570,621.00)	(1,570,621.00)		
1551 Smart Metering Entity Variance	(41,605.39)				(41,605.39)		
1576 Accounting Changes Under CGAAP	(1,269,972.10)				(1,269,972.10)		
1580 RSVA - WMS	(4,043,656.33)				(4,043,656.33)		
1582 RSVA - One Time	0.00				0.00		
1586 RSVA - CN	(729,945.68)				(729,945.68)		
1588 RSVA - Power	(3,231,264.85)				(3,231,264.85)		
1562 Deferred Payments in Lieu of taxes	0.00				0.00		
1563 Deferred PILS contra Account	0.00				0.00		
1557 Mist meter variance	(83,717.85)				(83,717.85)		
1521 Special Purpose Charge	0.00				0.00		
1595 Disposition and Recovery of Regulatory Balances	(162,964.18)	(10,549,249.38)	(10,549,249.38)	(119,153.55)	(282,117.73)	(12,239,023.93)	(12,239,023.93)
3005 Common Shares Issued	(31,245,882.02)	(31,245,882.02)			(31,245,882.02)	(31,245,882.02)	
3010 Contributed Surplus	0.00			(18,753,902.09)	(18,753,902.09)		
3047 Appropriations of Retained Earnings - current	(6,705,305.00)	(6,705,305.00)			(6,705,305.00)	(25,459,207.09)	
3040 Appropriated Retained Earnings	(37,333,976.50)			6,145,222.27	(31,188,754.23)		
3041 Appropriated Retained Earnings							
3046 Balance Transferred from Income	(5,157,562.75)			1,084,544.52	(4,073,018.23)		
3049 Dividends payable - Common Shares	1,400,000.00	(41,091,539.25)	(79,042,726.27)		1,400,000.00	(33,861,772.46)	(90,566,861.57)
Balance Sheet	**0.00**	**0.00**	**0.00**	**(0.00)**	**0.00**	**0.00**	**0.00**
4006 Residential Energy Sales	(49,825,343.60)				(49,825,343.60)		
4010 Commercial Energy Sales	(15,726,833.42)				(15,726,833.42)		
4025 Streetlighting energy sales	(578,429.73)				(578,429.73)		
4030 Sentinel Lighting Energy Sales	(21,285.51)				(21,285.51)		
4035 General Energy Sales	(75,497,567.90)				(75,497,567.90)		
4062 Billed WMS	(7,587,998.50)				(7,587,998.50)		
4066 Billed NW	(9,193,666.18)				(9,193,666.18)		

	RRR = Financial Statements December 2016	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry presentation on FS	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
4068 Billed CN	(6,219,058.72)				(6,219,058.72)		
4075 Billed - LV	(526,001.35)				(526,001.35)		
4076 Billed SME Charge	(492,877.33)	(165,669,062.24)	(165,669,062.24)		(492,877.33)	(165,669,062.24)	(165,669,062.24)
4080 Distribution Services Revenue	(28,384,553.00)			2,630,554.35	(25,753,998.65)		
4082 Retail Services Revenue	(34,360.80)				(34,360.80)		
4084 Service Transaction Requests (STR) Revenues	(656.50)				(656.50)		
4086 SSS Admin Charge	(149,418.99)	(28,568,989.29)	(28,568,989.29)		(149,418.99)	(25,938,434.94)	(25,938,434.94)
4215 Other Utility Operating Income	(41,441.70)				(41,441.70)		
4225 Late Payment Charges	(429,277.11)				(429,277.11)		
4235 Miscellaneous Service Revenues	(1,665,729.36)				(1,665,729.36)		
4355 Gain on Disposition of Utility and Other Property	(3,010.18)				(3,010.18)		
4360 Loss on Disposition of Utility and Other Property	7,884.54				7,884.54		
4375 Revenues from Non-Utility Operations	(4,591,717.23)				(4,591,717.23)		
4380 Expenses from Non-Utility Operations	4,607,804.13				4,607,804.13		
4390 Miscellaneous Non-Operating Income	(95,183.29)	(2,210,670.20)	(2,210,670.20)		(95,183.29)	(2,210,670.20)	(2,210,670.20)
4705 Power Purchased	77,646,677.82			(1,152,985.24)	76,493,692.58		
4707 Global adjustment purchased	64,002,782.34				64,002,782.34		
4708 Charges -WMS	6,198,855.85				6,198,855.85		
4709 Charges - OESP	1,389,142.65				1,389,142.65		
4714 Charges -NW	9,193,666.18				9,193,666.18		
4716 Charges -CN	6,219,058.72				6,219,058.72		
4751 Charges -SME	526,001.35				526,001.35		
4750 Charges - LV	492,877.33	165,669,062.24	165,669,062.24		492,877.33	164,516,077.00	164,516,077.00
5005 Operation Supervision and Engineering	1,044,089.86				1,044,089.86		
5010 Load Dispatching	11,339.75				11,339.75		
5012 Station Buildings and fixtures expense	132,484.47				132,484.47		
5014 Transformer Station Equipment - Operation Labour	22,482.65				22,482.65		
5015 Transformer Station Equipment - Operation	188,473.88				188,473.88		
5020 Overhead Distribution Lines and Feeders -Labour	355,961.06				355,961.06		
5025 Overhead Distribution Lines and Feeders - Operation expenses	2,207.53				2,207.53		
5040 Underground Distribution Lines and Feeders Labour	169,455.68				169,455.68		
5045 Underground Distribution Lines and Feeders - expenses	373,440.45				373,440.45		
5055 Underground Distribution Transformer - Operations	0.00				0.00		
5065 Meter Expense	374,868.22				374,868.22		
5085 Miscellaneous Distribution Expenses	1,616,825.17				1,616,825.17		
5105 Maintenance Supervision and Engineering	428,313.57				428,313.57		
5112 Maintenance of Transformer Station Equipment	10,498.75				10,498.75		
5114 Maintenance of Distribution Station Equipment	19,894.20				19,894.20		
5120 Maintenance of Poles, Towers and Fixtures	88,701.96				88,701.96		
5125 Maintenance of Overhead Conductors and Devices	613,170.18				613,170.18		
5130 Maintenance of Overhead Services	157,461.75				157,461.75		
5135 Overhead Distribution Lines and Feeders - Right of Way	348,649.19				348,649.19		
5145 Maintenance of Underground Conduit	75,262.62				75,262.62		
5150 Maintenance of Underground Conductors & Devices	186,908.42				186,908.42		
5155 Maintenance of Underground Services	158,894.24				158,894.24		
5160 Maintenance of Line Transformers	113,635.25				113,635.25		
5175 Maintenance of Meters	1,725.18	6,494,744.03			1,725.18	6,494,744.03	6,494,744.03
5070 Customer Premises - Operation Labour	119,696.10				119,696.10		
5405 Supervision	1,386.68				1,386.68		
5410 Community Relations - Sundry	98,327.22	219,410.00			98,327.22	219,410.00	219,410.00
5305 Supervision	961,818.48				961,818.48		
5310 Meter Reading Expense	491,608.78			(39,199.00)	452,409.78		
5315 Customer Billing	2,830,913.62				2,830,913.62		
5320 Collecting	558,153.99				558,153.99		
5325 Collecting - Cash Over and Short	(48.53)				(48.53)		
5335 Bad Debt Expense	218,351.84				218,351.84		
5340 Miscellaneous Customer Accounts Expense	234,978.73	5,295,776.91		83,479.60	318,458.33	5,340,057.51	5,340,057.51
5605 Executive Salaries and Expenses	414,877.35				414,877.35		
5610 Management Salaries and Expenses	2,250,334.93				2,250,334.93		
5615 General Administrative Salaries and Expenses	540,277.03			68,029.00	608,306.03		
5620 Office Supplies and Expenses	80,112.22				80,112.22		

	RRR = Financial Statements December 2016	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry presentation on FS	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
5630 Outside Services Employed	65,455.00				65,455.00		
5635 Property Insurance	327,945.43				327,945.43		
5655 Regulatory Expenses	323,379.67				323,379.67		
5665 Miscellaneous General Expense	69,003.27				69,003.27		
5675 Maintenance of General Plant	678,086.39				678,086.39		
6105 Taxes other that Income Taxes	310,315.82				310,315.82		
6205 Donations	76,801.68	5,136,588.79			76,801.68	5,204,617.79	5,204,617.79
5705 Amortization Expense - Property Plant and Equipment	6,462,384.94	6,462,384.94		0.00	6,462,384.94	6,462,384.94	6,462,384.94
5715 Amortization of Intangibles and Other Electric	0.00	0.00		1,084,544.52	1,084,544.52	1,084,544.52	1,084,544.52
4405 Interest and Dividend Income	(185,198.79)	(185,198.79)		77,084.44	(108,114.35)	(108,114.35)	(108,114.35)
6005 Interest on Long Term Debt	1,195,428.77				1,195,428.77		
6030 Interest on Debt to Associated Companies	1,221,362.76				1,221,362.76		
6035 Other Interest Expense	159,817.33	2,576,608.86	26,000,314.74	(149,066.06)	10,751.27	2,427,542.80	2,427,542.80
6215 Penalties	0.00				0.00		
6110 Income Taxes	(188,872.00)				(188,872.00)		
6115 Provision for Future Income Taxes	(189,346.00)	(378,218.00)	(378,218.00)	616,251.00	426,905.00	238,033.00	238,033.00
Net Income for the year	**(5,157,562.75)**	**(5,157,562.75)**	**(5,157,562.75)**	**3,218,692.61**	**(1,938,870.14)**	**(1,938,870.14)**	**(1,938,870.14)**
Net movement in regulatory balances, net of tax	0.00	0.00	0.00	(2,134,148.09)	(2,134,148.09)	(2,134,148.09)	(2,134,148.09)
Net income, net movement in regulatory balances	**(5,157,562.75)**	**(5,157,562.75)**	**(5,157,562.75)**	**1,084,544.52**	**(4,073,018.23)**	**(4,073,018.23)**	**(4,073,018.23)**
Trial Balance Summary							
Revenues	(196,448,721.73)	(196,448,721.73)	(196,448,721.73)	496,406.26	(195,952,315.47)	(195,952,315.47)	(195,952,315.47)
Expenses	191,291,158.98	191,291,158.98	191,291,158.98	588,138.26	191,879,297.24	191,879,297.24	191,879,297.24
(Profit)/Loss	(5,157,562.75)	(5,157,562.75)	(5,157,562.75)	1,084,544.52	(4,073,018.23)	(4,073,018.23)	(4,073,018.23)
Net Assets	181,686,020.11	180,699,897.11	205,653,772.19	11,524,135.30	193,210,155.41	192,224,032.41	217,866,359.21
Net Liabilities and Equity	(181,686,020.11)	(180,699,897.11)	(205,653,772.19)	(11,524,135.30)	(193,210,155.41)	(192,224,032.41)	(217,866,359.21)
IS (Profit)/Loss	(5,157,562.75)	(5,157,562.75)	(5,157,562.75)	1,084,544.52	(4,073,018.23)	(4,073,018.23)	(4,073,018.23)
Balance Sheet (profit)/Loss	(5,157,562.75)	(5,157,562.75)	(5,157,562.75)	1,084,544.52	(4,073,018.23)	(4,073,018.23)	(4,073,018.23)
	(0.00)	0.00	0.00	0.00	(0.00)	0.00	0.00

Niagara Peninsula Energy Inc.
For the Twelve Months Ending December 31, 2016
RRR Part 2
Trial Balance by Account
2.1.13

	Filed RRR excluding FMV entry	Adjustments for FMV entry presentation on FS	Audited Financial Statement December 2016
Current Assets			
1005 Cash	21,561,403.67		21,561,403.67
1010 Cash Advance and Working Funds	2,340.06		2,340.06
1100 Custom Accounts Receivable	13,691,762.06		13,691,762.06
1104 Accounts Receivable - Recoverable Work	668,332.20		668,332.20
1110 Other Accounts Receivable	888,648.49		888,648.49
1120 Accrued Utility Revenues	17,220,600.80		17,220,600.80
1130 Accumulated Provision for Uncollectible Accts	(544,268.40)		(544,268.40)
1180 Prepayments	1,109,502.97		1,109,502.97
1200 Accounts Receivable from Associated Companies	5,981.82		5,981.82
1330 Plant Materials and Operating Supplies	1,364,873.93		1,364,873.93
1495 Other Assets and Deferred Charges	3,721,217.75		3,721,217.75
1508 Other Regulatory Assets-Lead/Lag Study	(1,499,569.31)	1,566,187.28	66,617.97
1508 Other Regulatory Assets Incremental Capital Charges Hydro One	0.00	4,433.72	4,433.72
1508 Other Regulatory Assets - OPEB	0.00	(1,570,621.00)	(1,570,621.00)
1518 RCVA - Retail	54,100.61		54,100.61
1548 RCVA - STR	169,264.53		169,264.53
1550 Hydro One Low Voltage Variance	1,281,720.45		1,281,720.45
1551 Smart Metering Entity Variance	(41,605.39)		(41,605.39)
1555 Smart Meter Capital and Recovery Variance	203,886.41		203,886.41
1557 Mist meter variance	(83,717.85)		(83,717.85)
1568 LRAM variance	495,195.15		495,195.15
1576 Accounting Changes Under CGAAP	(1,269,972.10)		(1,269,972.10)
1580 RSVA - WMS	(4,043,656.33)		(4,043,656.33)
1584 RSVA - NW	383,007.69		383,007.69
1586 RSVA - CN	(729,945.68)		(729,945.68)
1588 RSVA - Power	(3,231,264.85)		(3,231,264.85)
1589 RSVA - GA Non-RPP	1,028,719.79		1,028,719.79
1595 Disposition and Recovery of Regulatory Balances	(162,964.18)		(162,964.18)
1606 Organization	1,926.45		1,926.45
1611 Computer Software	3,754,791.74		3,754,791.74
1612 Land Rights	1,604,396.58		1,604,396.58
1705 Land	82,347.02		82,347.02
1708 Buildings and Fixtures	3,693,130.15		3,693,130.15
1715 Station Equipment	2,742,786.83		2,742,786.83
1735 Underground Conduit	1,090.59		1,090.59
1740 Underground Conductors and Devices	138,793.40		138,793.40
1805 Land	424,925.77		424,925.77
1808 Buildings and Fixtures	111,638.13		111,638.13
1815 Transformer Station Equipment - Normally Primary	77,002.22		77,002.22
1820 Distribution Station Equipment - Normally Primary	6,867,625.70		6,867,625.70
1830 Poles, Towers and Fixtures	50,015,120.93		50,015,120.93
1835 Overhead Conductors and Devices	34,575,301.36		34,575,301.36
1840 Underground Conduit	12,338,449.27		12,338,449.27
1845 Underground Conductors and Devices	76,896,409.72	516,338.79	77,412,748.51
1850 Line Transformers	41,954,237.25	172,112.93	42,126,350.18
1855 Services	8,465,324.66		8,465,324.66
1860 Meters	10,215,217.08		10,215,217.08
1865 Other Installations on Customer's Premises	439.87		439.87
1875 Street Lighting and Signal Systems	21,835.21		21,835.21
1905 Land	508,969.83		508,969.83
1908 Buildings and Fixtures	17,251,915.94		17,251,915.94
1910 Leasehold Improvements	120,252.32		120,252.32
1915 Office Furniture and Equipment	1,723,807.92		1,723,807.92
1920 Computer Equipment-Hardware	4,547,110.82		4,547,110.82

	Filed RRR excluding FMV entry	Adjustments for FMV entry presentation on FS	Audited Financial Statement December 2016
1930 Transportation Equipment	9,074,201.71		9,074,201.71
1935 Stores Equipment	323,279.08		323,279.08
1940 Tools, Shop and Garage Equipment	2,200,663.23		2,200,663.23
1945 Measurement and Testing Equipment	204,006.18		204,006.18
1955 Communication Equipment	1,442,918.22		1,442,918.22
1960 Miscellaneous Equipment	72,951.31		72,951.31
1980 System Supervisory Equipment	128,960.64		128,960.64
1995 Contributions and Grants - Credit	(23,195,905.23)	(688,451.72)	(23,884,356.95)
2005 Property Under Capital Leases	143,036.00		143,036.00
2060 Electric Plant Acquisition Adjustment	142,276.60		142,276.60
2065 Other Electric Plant Adjustment	0.00	45,509,515.44	45,509,515.44
2105 Accumulated Amortization of Electric Utility-Plant	(134,811,126.38)		(134,811,126.38)
2120 Accumulated Amortization of Electric Utility Plant-Intangibles	(4,327,923.70)		(4,327,923.70)
2140 Accumulated Amortization of Electric Plant	(142,276.60)		(142,276.60)
2160 Accumulated Amortization of Other Utility Plant	0.00	(33,985,380.14)	(33,985,380.14)
2205 Accounts Payable	(19,482,227.66)		(19,482,227.66)
2210 Current portion of Customer deposits	(1,505,461.07)		(1,505,461.07)
2240 Accounts Payable to Associated Companies	0.00		0.00
2250 Debt Retirement Charges DRC payable	(453,311.50)		(453,311.50)
2260 Current Portion of Long Term Debt	(11,466,354.84)		(11,466,354.84)
2290 Commodity Taxes	1,499,574.07		1,499,574.07
2292 Payroll Deductions/Expenses Payable	(1,341.49)		(1,341.49)
2294 Accrual for Taxes,"Payments in Lieu"of Taxes	1,757,969.85		1,757,969.85
2296 Future Income Taxes - Current	0.00		0.00
2306 Employee Future Benefits	(2,619,248.00)		(2,619,248.00)
2310 Vested Sick Leave Liability	(55,182.42)		(55,182.42)
2320 Other Miscellaneous Non-current liabilities	(37,334.17)		(37,334.17)
2350 Future Income Tax - Non Current	52,518.00		52,518.00
2405 Other Regulatory Liabilities	(986,123.00)		(986,123.00)
2425 Other Deferred Credits	(713,946.99)		(713,946.99)
2525 Term Bank Loans-long term Portion	(42,975,216.90)		(42,975,216.90)
2550 Advances from Associated Companies	(25,605,089.72)		(25,605,089.72)
3005 Common Shares Issued	(31,245,882.02)		(31,245,882.02)
3010 Contributed Surplus	0.00	(18,753,902.09)	(18,753,902.09)
3040 Appropriated Retained Earnings	(37,333,976.50)	6,145,222.27	(31,188,754.23)
3046 Balance Transferred from Income	(5,157,562.75)	1,084,544.52	(4,073,018.23)
3047 Appropriations of Retained Earnings - current	(6,705,305.00)		(6,705,305.00)
3049 Dividends payable - Common Shares	1,400,000.00		1,400,000.00
Balance Sheet	0.00	(0.00)	0.00

4006 Residential Energy Sales	(49,825,343.60)		(49,825,343.60)
4010 Commercial Energy Sales	(15,726,833.42)		(15,726,833.42)
4025 Streetlighting energy sales	(578,429.73)		(578,429.73)
4030 Sentinel Lighting Energy Sales	(21,285.51)		(21,285.51)
4035 General Energy Sales	(75,497,567.90)		(75,497,567.90)
4062 Billed WMS	(7,587,998.50)		(7,587,998.50)
4066 Billed NW	(9,193,666.18)		(9,193,666.18)
4068 Billed CN	(6,219,058.72)		(6,219,058.72)
4075 Billed - LV	(526,001.35)		(526,001.35)
4076 Billed SME Charge	(492,877.33)		(492,877.33)
4080 Distribution Services Revenue	(28,384,553.00)	2,630,554.35	(25,753,998.65)
4082 Retail Services Revenue	(34,360.80)		(34,360.80)
4084 Service Transaction Requests (STR) Revenues	(656.50)		(656.50)
4086 SSS Admin Charge	(149,418.99)		(149,418.99)
4215 Other Utility Operating Income	(41,441.70)		(41,441.70)
4225 Late Payment Charges	(429,277.11)		(429,277.11)
4235 Miscellaneous Service Revenues	(1,665,729.36)		(1,665,729.36)
4355 Gain on Disposition of Utility and Other Property	(3,010.18)		(3,010.18)
4360 Loss on Disposition of Utility and Other Property	7,884.54		7,884.54
4375 Revenues from Non-Utility Operations	(4,591,717.23)		(4,591,717.23)

	Filed RRR excluding FMV entry	Adjustments for FMV entry presentation on FS	Audited Financial Statement December 2016
4380 Expenses from Non-Utility Operations	4,607,804.13		4,607,804.13
4390 Miscellaneous Non-Operating Income	(95,183.29)		(95,183.29)
4405 Interest and Dividend Income	(185,198.79)	77,084.44	(108,114.35)
4705 Power Purchased	77,646,677.82	(1,152,985.24)	76,493,692.58
4707 Global adjustment purchased	64,002,782.34		64,002,782.34
4708 Charges -WMS	6,198,855.85		6,198,855.85
4709 Charges - OESP	1,389,142.65		1,389,142.65
4714 Charges -NW	9,193,666.18		9,193,666.18
4716 Charges -CN	6,219,058.72		6,219,058.72
4750 Charges - LV	526,001.35		526,001.35
4751 Charges - SME	492,877.33		492,877.33
5005 Operation Supervision and Engineering	1,044,089.86		1,044,089.86
5010 Load Dispatching	11,339.75		11,339.75
5012 Station Buildings and fixtures expense	132,484.47		132,484.47
5014 Transformer Station Equipment - Operation Labour	22,482.65		22,482.65
5015 Transformer Station Equipment - Operation	188,473.88		188,473.88
5020 Overhead Distribution Lines and Feeders -Labour	355,961.06		355,961.06
5025 Overhead Distribution Lines and Feeders - Operation expenses	2,207.53		2,207.53
5040 Underground Distribution Lines and Feeders Labour	169,455.68		169,455.68
5045 Underground Distribution Lines and Feeders - expenses	373,440.45		373,440.45
5055 Underground Distribution Transformers - Operation	0.00		0.00
5065 Meter Expense	374,868.22		374,868.22
5070 Customer Premises - Operation Labour	119,696.10		119,696.10
5085 Miscellaneous Distribution Expenses	1,616,825.17		1,616,825.17
5105 Maintenance Supervision and Engineering	428,313.57		428,313.57
5112 Maintenance of Transformer Station Equipment	10,498.75		10,498.75
5114 Maintenance of Distribution Station Equipment	19,894.20		19,894.20
5120 Maintenance of Poles, Towers and Fixtures	88,701.96		88,701.96
5125 Maintenance of Overhead Conductors and Devices	613,170.18		613,170.18
5130 Maintenance of Overhead Services	157,461.75		157,461.75
5135 Overhead Distribution Lines and Feeders - Right of Way	348,649.19		348,649.19
5145 Maintenance of Underground Conduit	75,262.62		75,262.62
5150 Maintenance of Underground Conductors & Devices	186,908.42		186,908.42
5155 Maintenance of Underground Services	158,894.24		158,894.24
5160 Maintenance of Line Transformers	113,635.25		113,635.25
5175 Maintenance of Meters	1,725.18		1,725.18
5305 Supervision	961,818.48		961,818.48
5310 Meter Reading Expense	491,608.78	(39,199.00)	452,409.78
5315 Customer Billing	2,830,913.62		2,830,913.62
5320 Collecting	558,153.99		558,153.99
5325 Collecting - Cash Over and Short	(48.53)		(48.53)
5335 Bad Debt Expense	218,351.84		218,351.84
5340 Miscellaneous Customer Accounts Expense	234,978.73	83,479.60	318,458.33
5405 Supervision	1,386.68		1,386.68
5410 Community Relations - Sundry	98,327.22		98,327.22
5605 Executive Salaries and Expenses	414,877.35		414,877.35
5610 Management Salaries and Expenses	2,250,334.93	68,029.00	2,318,363.93
5615 General Administrative Salaries and Expenses	540,277.03		540,277.03
5620 Office Supplies and Expenses	80,112.22		80,112.22
5630 Outside Services Employed	65,455.00		65,455.00
5635 Property Insurance	327,945.43		327,945.43
5655 Regulatory Expenses	323,379.67		323,379.67
5665 Miscellaneous General Expense	69,003.27		69,003.27
5675 Maintenance of General Plant	678,086.39		678,086.39
5705 Amortization Expense - Property Plant and Equipment	6,462,384.94		6,462,384.94
5715 Amortization of Intangibles and Other Electric	0.00	1,084,544.52	1,084,544.52
6005 Interest on Long Term Debt	1,195,428.77		1,195,428.77
6030 Interest on Debt to Associated Companies	1,221,362.76		1,221,362.76
6035 Other Interest Expense	159,817.33	(149,066.06)	10,751.27
6105 Taxes other that Income Taxes	310,315.82		310,315.82
6110 Income Taxes	(188,872.00)		(188,872.00)
6115 Provision for Future Income Taxes	(189,346.00)	616,251.00	426,905.00
6205 Donations	76,801.68		76,801.68

	Filed RRR excluding FMV entry	Adjustments for FMV entry presentation on FS	Audited Financial Statement December 2016
Net movement in regulatory balances, net of tax	0.00	(2,134,148.09)	(2,134,148.09)
Income Statement total	**(5,157,562.75)**	**1,084,544.52**	**(4,073,018.23)**
Trial Balance Summary			
Revenues	(196,633,920.52)	2,707,638.79	(193,926,281.73)
Expenses	191,476,357.77	(1,623,094.27)	189,853,263.50
(Profit)/Loss	(5,157,562.75)	1,084,544.52	(4,073,018.23)
Net Assets	320,629,516.19	0.00	320,629,516.19
Net Liabilities and Equity	(320,629,516.19)	(0.00)	(320,629,516.19)
IS (Profit)/Loss	(5,157,562.75)	1,084,544.52	(4,073,018.23)
Balance Sheet (profit)/Loss	(5,157,562.75)	1,084,544.52	(4,073,018.23)

Niagara Peninsula Energy Inc.
FMV Bump
2.1.13

Balance Sheet

		2007 FMV entry	Entry hits Retained Earnings	2007 FMV entry summary	2012	2013	2014	2015	2016
1	PWU AR PWPower	(216,069.30)	216,069.30						
1	Due from PW power	1,400,000.00	(1,400,000.00)						
1	Future PILS	(5,168,552.00)	5,168,552.00						
1	Inventory	7,684.34	(7,684.34)						
	Fixed assets Total FMV Bump	45,735,559.44		45,735,559.44					
	Adjustment for PW software								
					45,509,515.44	45,509,515.44	45,509,515.44	45,509,515.44	45,509,515.44
	Accum Deprec Total FMV Bump	(24,083,153.39)		(24,083,153.39)	(28,442,637)	(29,580,061)	(30,712,338)	(31,811,977)	(32,900,837)
	Adjustment for PW software								
	Current year depreciation				(1,137,424)	(1,132,277)	(1,099,638)	(1,088,860)	(1,084,545)
					(29,580,061)	(30,712,338)	(31,811,977)	(32,900,837)	(33,985,381)
	Contributed Surplus	(18,753,902.09)		(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)
1	Retained Earnings	1,078,433.00	(1,078,433.00)	-					
sum of 1's	Retained Earnings net adjustment		(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)
	Cummulative impact on RE for Depreciation FMV bump				4,585,528	5,722,952	6,855,229	7,954,867	9,043,727
	Depreciation expense to be closed to Cummulative impact on RE				1,137,424	1,132,277	1,099,638	1,088,860	1,084,544
	Net	(0.00)	-	-	(0.00)	-	-	-	(0.00)

Income Statement

	2012	2013	2014	2015	2016
Depreciation expense FMV bump	1,137,424	1,132,277	1,099,638	1,088,860	1,084,545
Adjust depreciation expense FMV bump	0				
	1,137,424	1,132,277	1,099,638	1,088,860	1,084,545

Niagara Peninsula Energy Inc.
For the Twelve Months Ending December 31, 2015

RRR Part 1
Trial Balance Mapped to Financial Statement Grouping
2.1.13

	RRR = Financial Statements December 2015	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry presentation on FS	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
1005 Cash	9,046,081.08				9,046,081.08		
1010 Cash Advance and Working Funds	2,913.23	9,048,994.31			2,913.23	9,048,994.31	
1100 Custom Accounts Receivable	12,409,593.26				12,409,593.26		
1104 Accounts Receivable - Recoverable Work	1,969,034.42				1,969,034.42		
1110 Other Accounts Receivable	723,397.19				723,397.19		
1130 Accumulated Provision for Uncollectible Accts	(495,427.46)	14,606,597.41			(495,427.46)	14,606,597.41	
1120 Accrued Utility Revenues	17,383,378.11	17,383,378.11			17,383,378.11	17,383,378.11	
1200 Accounts Receivable from Associated Companies	0.00	0.00			0.00	0.00	
2294 Accrual for Taxes,"Payments in Lieu"of Taxes	306,278.20	306,278.20			306,278.20	306,278.20	
1180 Prepayments	1,110,584.39				1,110,584.39		
1606 Organization	0.00	1,110,584.39		1,926.45	1,926.45	1,112,510.84	
1330 Plant Materials and Operating Supplies	1,498,946.98	1,498,946.98	43,954,779.40		1,498,946.98	1,498,946.98	43,956,705.85
1606 Organization	1,926.45			(1,926.45)	0.00		
1705 Land	82,347.02				82,347.02		
1708 Buildings and Fixtures	3,693,130.15				3,693,130.15		
1715 Station Equipment	2,742,786.83				2,742,786.83		
1735 Underground Conduit	1,090.59				1,090.59		
1740 Underground Conductors and Devices	138,793.40				138,793.40		
1805 Land	424,925.77				424,925.77		
1612 Land Rights	1,604,396.58				1,604,396.58		
1808 Buildings and Fixtures	111,638.13				111,638.13		
1815 Transformer Station Equipment - Normally Primary	77,002.22				77,002.22		
1820 Distribution Station Equipment - Normally Primary	6,867,625.70				6,867,625.70		
1830 Poles, Towers and Fixtures	47,353,345.26				47,353,345.26		
1835 Overhead Conductors and Devices	32,112,729.74				32,112,729.74		
1840 Underground Conduit	11,140,555.00				11,140,555.00		
1845 Underground Conductors and Devices	73,603,818.39				73,603,818.39		
1850 Line Transformers	40,618,575.44				40,618,575.44		
1855 Services	7,282,469.66				7,282,469.66		
1860 Meters	9,725,655.34				9,725,655.34		
1865 Other Installations on Customer's Premises	439.87				439.87		
1875 Street Lighting and Signal Systems	21,835.21				21,835.21		
1905 Land	508,969.83				508,969.83		
1908 Buildings and Fixtures	17,199,162.49				17,199,162.49		
1910 Leasehold Improvements	120,252.32				120,252.32		
1915 Office Furniture and Equipment	1,695,777.34				1,695,777.34		
1920 Computer Equipment-Hardware	4,305,893.93				4,305,893.93		
1611 Computer Software	3,412,314.72				3,412,314.72		
1930 Transportation Equipment	8,778,182.91				8,778,182.91		
1935 Stores Equipment	323,279.08				323,279.08		
1940 Tools, Shop and Garage Equipment	2,081,941.57				2,081,941.57		
1945 Measurement and Testing Equipment	204,006.18				204,006.18		
1955 Communication Equipment	1,140,928.54				1,140,928.54		
1960 Miscellaneous Equipment	72,951.31				72,951.31		
1980 System Supervisory Equipment	128,960.64				128,960.64		
2005 Property Under Capital Leases	143,036.00				143,036.00		
2060 Electric Plant Acquisition Adjustment	142,276.60				142,276.60		
2065 Other Electric Plant Adjustment	0.00			45,509,515.44	45,509,515.44		
2105 Accumulated Amortization of Electric Utility-Plant	(129,361,542.40)				(129,361,542.40)		
2120 Accumulated Amortization of Electric Utility Plant-Intangibles	(4,040,599.15)				(4,040,599.15)		
2140 Accumulated Amortization of Electric Plant	(142,276.60)				(142,276.60)		
2160 Accumulated Amortization of Other Utility Plant	0.00	144,318,602.06	144,318,602.06	(32,900,835.62)	(32,900,835.62)	156,925,355.43	156,925,355.43
1508 Other Regulatory Assets	(1,534,202.31)			1,570,621.00	36,418.69		
1495 Deferred Taxes-Non-current assets	4,842,211.75			142,183.33	4,984,395.08		
1550 Hydro One Low Voltage Variance	579,415.11				579,415.11		

	RRR = Financial Statements December 2015	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry presentation on FS	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
1584 RSVA - NW	336,882.92				336,882.92		
1589 RSVA - GA Non-RPP	2,862,341.74			1,304,284.33	4,166,626.07		
1518 RCVA - Retail	36,134.08				36,134.08		
1548 RCVA - STR	103,751.46				103,751.46		
1568 LRAM variance	481,097.10				481,097.10		
1535 Smart Grid Deferral Account	0.00				0.00		
1555 Smart Meter Capital and Recovery Variance	880,350.95				880,350.95		
1595 Disposition and Recovery of Regulatory Balances	73,673.99	8,661,656.79	8,661,656.79	175,850.55	249,524.54	11,854,596.00	11,854,596.00
2205 Accounts Payable	(20,358,181.02)				(20,358,181.02)		
2250 Debt Retirement Charges DRC payable	(722,233.97)				(722,233.97)		
2290 Commodity Taxes	1,445,992.62				1,445,992.62		
2292 Payroll Deductions/Expenses Payable	(1,467.90)	(19,635,890.27)			(1,467.90)		
2210 Current portion of customer deposits	(1,495,704.05)				(1,495,704.05)		
2320 Other Miscellaneous Non-current liabilities	(37,334.17)	(1,533,038.22)			(37,334.17)		
2220 Miscellaneous Current and Accrued Liabilities	0.00				0.00		
2425 Other Deferred Credits	(830,673.09)	(830,673.09)			(830,673.09)	(21,999,601.58)	
2210 Current portion of Customer deposits	0.00	0.00			0.00	0.00	
2240 Accounts Payable to Associated Companies	(7,354.50)	(7,354.50)			(7,354.50)	(7,354.50)	
2260 Current Portion of Long Term Debt	(1,420,497.90)	(1,420,497.90)	(23,427,453.98)		(1,420,497.90)	(1,420,497.90)	(23,427,453.98)
2520 Other Long Term debt	0.00				0.00		
2525 Term Bank Loans-long term Portion	(34,441,571.78)				(34,441,571.78)		
2550 Advances from Associated Companies	(25,605,089.72)	(60,046,661.50)			(25,605,089.72)	(60,046,661.50)	
2335 Long Term Customer Deposits	0.00	0.00			0.00		
2310 Vested Sick Leave Liability	(52,227.84)	(52,227.84)			(52,227.84)	(52,227.84)	
2306 Employee Future Benefits	(2,504,100.00)	(2,504,100.00)			(2,504,100.00)	(2,504,100.00)	
1995 Contributions and Grants - Credit	(20,591,344.22)	(20,591,344.22)			(20,591,344.22)	(20,591,344.22)	
2350 Future Income Tax - non current	(1,480,008.00)	(1,480,008.00)	(84,674,341.56)		(1,480,008.00)	(1,480,008.00)	
2405 Other Regulatory liabilities	(763,937.00)			(142,183.33)	(906,120.33)		
1508 Other Regulatory Assets - OPEB	0.00			(1,570,621.00)	(1,570,621.00)		
1551 Smart Metering Entity Variance	(31,359.50)				(31,359.50)		
1576 Accounting Changes Under CGAAP	(4,823,033.88)				(4,823,033.88)		
1580 RSVA - WMS	(2,759,401.03)				(2,759,401.03)		
1582 RSVA - One Time	0.00				0.00		
1586 RSVA - CN	(400,001.39)				(400,001.39)		
1588 RSVA - Power	(4,726,426.53)			(1,304,284.33)	(6,030,710.86)		
1562 Deferred Payments in Lieu of taxes	0.00				0.00		
1563 Deferred PILS contra Account	0.00				0.00		
1557 Mist meter variance	(43,920.86)				(43,920.86)		
1521 Special Purpose Charge	0.00				0.00		
1595 Disposition and Recovery of Regulatory Balances	0.00	(13,548,080.19)	(13,548,080.19)	(175,850.55)	(175,850.55)	(16,741,019.40)	(101,415,360.96)
3005 Common Shares Issued	(31,245,882.02)	(31,245,882.02)			(31,245,882.02)	(31,245,882.02)	
3010 Contributed Surplus	0.00			(18,753,902.09)	(18,753,902.09)		
3047 Appropriations of Retained Earnings - current	(6,705,305.00)	(6,705,305.00)			(6,705,305.00)	(25,459,207.09)	
3040 Appropriated Retained Earnings	(33,207,788.54)			5,056,362.09	(28,151,426.45)		
3041 Appropriated Retained Earnings							
3046 Balance Transferred from Income	(5,326,186.96)			1,088,860.18	(4,237,326.78)		
3049 Dividends payable - Common Shares	1,200,000.00	(37,333,975.50)	(75,285,162.52)		1,200,000.00	(31,188,753.23)	(87,893,842.34)
Balance Sheet	**0.00**	**0.00**	**0.00**	**(0.00)**	**(0.00)**	**0.00**	**0.00**
4006 Residential Energy Sales	(44,390,303.90)				(44,390,303.90)		
4010 Commercial Energy Sales	(13,901,587.88)				(13,901,587.88)		
4025 Streetlighting energy sales	(720,694.26)				(720,694.26)		
4030 Sentinel Lighting Energy Sales	(20,553.99)				(20,553.99)		
4035 General Energy Sales	(68,138,892.37)				(68,138,892.37)		
4062 Billed WMS	(7,176,971.28)				(7,176,971.28)		
4066 Billed NW	(9,441,201.42)				(9,441,201.42)		

	RRR = Financial Statements December 2015	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry presentation on FS	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
4068 Billed CN	(6,041,559.12)				(6,041,559.12)		
4075 Billed - LV	(524,910.03)				(524,910.03)		
4076 Billed SME Charge	(497,847.33)	(150,854,521.58)	(150,854,521.58)		(497,847.33)	(150,854,521.58)	(150,854,521.58)
4080 Distribution Services Revenue	(29,280,939.56)			2,970,479.02	(26,310,460.54)		
4082 Retail Services Revenue	(38,566.40)				(38,566.40)		
4084 Service Transaction Requests (STR) Revenues	(653.00)				(653.00)		
4086 SSS Admin Charge	(149,441.11)	(29,469,600.07)	(29,469,600.07)		(149,441.11)	(26,499,121.05)	(26,499,121.05)
4215 Other Utility Operating Income	(57,931.59)				(57,931.59)		
4225 Late Payment Charges	(424,468.10)				(424,468.10)		
4235 Miscellaneous Service Revenues	(1,428,148.99)				(1,428,148.99)		
4355 Gain on Disposition of Utility and Other Property	(29,600.00)				(29,600.00)		
4360 Losses from disposition of Utility and Other Property	0.00				0.00		
4362 Loss on Retirement of Utility and Other Property	0.00				0.00		
4375 Revenues from Non-Utility Operations	(3,100,130.29)				(3,100,130.29)		
4380 Expenses from Non-Utility Operations	2,821,817.52				2,821,817.52		
4390 Miscellaneous Non-Operating Income	(103,532.00)	(2,321,993.45)	(2,321,993.45)		(103,532.00)	(2,321,993.45)	(2,321,993.45)
4705 Power Purchased	76,950,762.62			(4,231,181.81)	72,719,580.81		
4707 Global adjustment purchased	50,212,491.26				50,212,491.26		
4708 Charges -WMS	7,176,467.19				7,176,467.19		
4714 Charges -NW	9,440,558.57				9,440,558.57		
4716 Charges -CN	6,041,117.94				6,041,117.94		
4751 Charges -SME	524,910.03				524,910.03		
4750 Charges - LV	497,847.33	150,844,154.94	150,844,154.94		497,847.33	146,612,973.13	146,612,973.13
5005 Operation Supervision and Engineering	935,223.10				935,223.10		
5010 Load Dispatching	34,680.28				34,680.28		
5012 Station Buildings and fixtures expense	51,354.90				51,354.90		
5014 Transformer Station Equipment - Operation Labour	30,415.48				30,415.48		
5015 Transformer Station Equipment - Operation	191,084.31				191,084.31		
5020 Overhead Distribution Lines and Feeders -Labour	221,646.72				221,646.72		
5025 Overhead Distribution Lines and Feeders - Operation expenses	76,219.57				76,219.57		
5040 Underground Distribution Lines and Feeders Labour	117,703.72				117,703.72		
5045 Underground Distribution Lines and Feeders - expenses	326,712.87				326,712.87		
5055 Underground Distribution Transformer - Operations	271.84				271.84		
5065 Meter Expense	469,026.05				469,026.05		
5085 Miscellaneous Distribution Expenses	1,732,082.80				1,732,082.80		
5105 Maintenance Supervision and Engineering	525,742.03				525,742.03		
5112 Maintenance of Transformer Station Equipment	0.00				0.00		
5114 Maintenance of Distribution Station Equipment	12,381.19				12,381.19		
5120 Maintenance of Poles, Towers and Fixtures	88,323.22				88,323.22		
5125 Maintenance of Overhead Conductors and Devices	781,873.64				781,873.64		
5130 Maintenance of Overhead Services	166,257.87				166,257.87		
5135 Overhead Distribution Lines and Feeders - Right of Way	291,160.91				291,160.91		
5145 Maintenance of Underground Conduit	39,937.83				39,937.83		
5150 Maintenance of Underground Conductors & Devices	226,672.07				226,672.07		
5155 Maintenance of Underground Services	121,575.68				121,575.68		
5160 Maintenance of Line Transformers	91,430.31				91,430.31		
5175 Maintenance of Meters	427.15	6,532,203.54			427.15	6,532,203.54	6,532,203.54
5070 Customer Premises - Operation Labour	124,059.16				124,059.16		
5410 Community Relations - Sundry	82,819.02	206,878.18		40,950.00	123,769.02	247,828.18	247,828.18
5305 Supervision	998,224.01				998,224.01		
5310 Meter Reading Expense	496,222.07			(43,760.00)	452,462.07		
5315 Customer Billing	2,711,004.73				2,711,004.73		
5320 Collecting	554,044.62				554,044.62		
5325 Collecting - Cash Over and Short	137.67				137.67		
5335 Bad Debt Expense	285,114.67				285,114.67		
5340 Miscellaneous Customer Accounts Expense	238,462.53	5,283,210.30		67,497.35	305,959.88	5,306,947.65	5,306,947.65
5605 Executive Salaries and Expenses	431,247.11				431,247.11		
5610 Management Salaries and Expenses	2,124,474.07				2,124,474.07		
5615 General Administrative Salaries and Expenses	464,011.73			(29,805.37)	434,206.36		
5620 Office Supplies and Expenses	78,511.44				78,511.44		
5630 Outside Services Employed	55,995.00				55,995.00		

	RRR = Financial Statements December 2015	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry presentation on FS	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
5635 Property Insurance	282,015.69				282,015.69		
5655 Regulatory Expenses	243,901.76				243,901.76		
5665 Miscellaneous General Expense	103,471.65				103,471.65		
5675 Maintenance of General Plant	725,448.89				725,448.89		
6105 Taxes other that Income Taxes	264,021.59				264,021.59		
6205 Donations	78,050.00	4,851,148.93		(40,950.00)	37,100.00	4,780,393.56	4,780,393.56
5705 Amortization Expense - Property Plant and Equipment	6,099,693.66	6,099,693.66		0.00	6,099,693.66	6,099,693.66	6,099,693.66
5715 Amortization of Intangibles and Other Electric	0.00	0.00		1,088,860.18	1,088,860.18	1,088,860.18	1,088,860.18
4405 Interest and Dividend Income	(180,679.95)	(180,679.95)		75,048.90	(105,631.05)	(105,631.05)	(105,631.05)
6005 Interest on Long Term Debt	1,138,961.06				1,138,961.06		
6030 Interest on Debt to Associated Companies	1,362,190.68				1,362,190.68		
6035 Other Interest Expense	856,629.18	3,357,780.92	26,150,235.58	(833,510.91)	23,118.27	2,524,270.01	2,524,270.01
6215 Penalties	0.00				0.00		
6110 Income Taxes	859,182.50				859,182.50		
6115 Provision for Future Income Taxes	(533,645.00)	325,537.50	325,537.50	1,401,526.00	867,881.00	1,727,063.50	1,727,063.50
Income Statement total	**(5,326,187.08)**	**(5,326,187.08)**	**(5,326,187.08)**	**465,153.36**	**(4,861,033.72)**	**(4,861,033.72)**	**(4,861,033.72)**
Net movement in regulatory balances, net of tax	0.00	0.00	0.00	623,706.82	623,706.82	623,706.82	623,706.82
Net income, net movement in regulatory balances	**(5,326,187.08)**	**(5,326,187.08)**	**(5,326,187.08)**	**1,088,860.18**	**(4,237,326.90)**	**(4,237,326.90)**	**(4,237,326.90)**
Trial Balance Summary							
Revenues	(182,646,115.10)	(182,646,115.10)	(182,646,115.10)	3,594,185.84	(179,051,929.26)	(179,051,929.26)	(179,051,929.26)
Expenses	177,319,928.02	177,319,928.02	177,319,928.02	(2,505,325.66)	174,814,602.36	174,814,602.36	174,814,602.36
(Profit)/Loss	(5,326,187.08)	(5,326,187.08)	(5,326,187.08)	1,088,860.18	(4,237,326.90)	(4,237,326.90)	(4,237,326.90)
Net Assets	163,253,272.64	162,489,335.64	183,386,958.06	12,750,863.15	176,004,135.79	175,098,015.46	111,321,296.32
Net Liabilities and Equity	(163,253,272.64)	(162,489,335.64)	(183,386,958.06)	(12,750,863.15)	(176,004,135.79)	(175,098,015.46)	(111,321,296.32)
IS (Profit)/Loss	(5,326,187.08)	(5,326,187.08)	(5,326,187.08)	1,088,860.18	(4,237,326.90)	(4,237,326.90)	(4,237,326.90)
Balance Sheet (profit)/Loss	(5,326,186.96)	(5,326,186.96)	(5,326,186.96)	1,088,860.18	(4,237,326.78)	(4,237,326.78)	(4,237,326.78)
	(0.12)	(0.12)	(0.12)	0.00	(0.12)	(0.12)	(0.12)

Niagara Peninsula Energy Inc.
For the Twelve Months Ending December 31, 2015
RRR Part 2
Trial Balance by Account
2.1.13

	Filed RRR excluding FMV entry	Adjustments for FMV entry presentation on FS	Audited Financial Statement December 2015
Current Assets			
1005 Cash	9,046,081.08		9,046,081.08
1010 Cash Advance and Working Funds	2,913.23		2,913.23
1100 Custom Accounts Receivable	12,409,593.26		12,409,593.26
1104 Accounts Receivable - Recoverable Work	1,969,034.42		1,969,034.42
1110 Other Accounts Receivable	723,397.19		723,397.19
1120 Accrued Utility Revenues	17,383,378.11		17,383,378.11
1130 Accumulated Provision for Uncollectible Accts	(495,427.46)		(495,427.46)
1180 Prepayments	1,110,584.39		1,110,584.39
1330 Plant Materials and Operating Supplies	1,498,946.98		1,498,946.98
1495 Other Assets and Deferred Charges	4,842,211.75	142,183.33	4,984,395.08
1508 Other Regulatory Assets-Lead/Lag Study	(1,534,202.31)	1,566,234.49	32,032.18
1508 Other Regulatory Assets Incremental Capital Charges Hydro One	0.00	4,386.51	4,386.51
1508 Other Regulatory Assets - OPEB	0.00	(1,570,621.00)	(1,570,621.00)
1518 RCVA - Retail	36,134.08		36,134.08
1548 RCVA - STR	103,751.46		103,751.46
1550 Hydro One Low Voltage Variance	579,415.11		579,415.11
1551 Smart Metering Entity Variance	(31,359.50)		(31,359.50)
1555 Smart Meter Capital and Recovery Variance	880,350.95		880,350.95
1557 Mist meter variance	(43,920.86)		(43,920.86)
1568 LRAM variance	481,097.10		481,097.10
1576 Accounting Changes Under CGAAP	(4,823,033.88)		(4,823,033.88)
1580 RSVA - WMS	(2,759,401.03)		(2,759,401.03)
1584 RSVA - NW	336,882.92		336,882.92
1586 RSVA - CN	(400,001.39)		(400,001.39)
1588 RSVA - Power	(4,726,426.53)	(1,304,284.33)	(6,030,710.86)
1589 RSVA - GA Non-RPP	2,862,341.74	1,304,284.33	4,166,626.07
1595 Disposition and Recovery of Regulatory Balances	73,673.99		73,673.99
1606 Organization	1,926.45		1,926.45
1611 Computer Software	3,412,314.72		3,412,314.72
1612 Land Rights	1,604,396.58		1,604,396.58
1705 Land	82,347.02		82,347.02
1708 Buildings and Fixtures	3,693,130.15		3,693,130.15
1715 Station Equipment	2,742,786.83		2,742,786.83
1735 Underground Conduit	1,090.59		1,090.59
1740 Underground Conductors and Devices	138,793.40		138,793.40
1805 Land	424,925.77		424,925.77
1808 Buildings and Fixtures	111,638.13		111,638.13
1815 Transformer Station Equipment - Normally Primary	77,002.22		77,002.22
1820 Distribution Station Equipment - Normally Primary	6,867,625.70		6,867,625.70
1830 Poles, Towers and Fixtures	47,353,345.26		47,353,345.26
1835 Overhead Conductors and Devices	32,112,729.74		32,112,729.74
1840 Underground Conduit	11,140,555.00		11,140,555.00
1845 Underground Conductors and Devices	73,603,818.39		73,603,818.39
1850 Line Transformers	40,618,575.44		40,618,575.44
1855 Services	7,282,469.66		7,282,469.66
1860 Meters	9,725,655.34		9,725,655.34
1865 Other Installations on Customer's Premises	439.87		439.87
1875 Street Lighting and Signal Systems	21,835.21		21,835.21
1905 Land	508,969.83		508,969.83
1908 Buildings and Fixtures	17,199,162.49		17,199,162.49
1910 Leasehold Improvements	120,252.32		120,252.32
1915 Office Furniture and Equipment	1,695,777.34		1,695,777.34
1920 Computer Equipment-Hardware	4,305,893.93		4,305,893.93

	Filed RRR excluding FMV entry	Adjustments for FMV entry presentation on FS	Audited Financial Statement December 2015
1930 Transportation Equipment	8,778,182.91		8,778,182.91
1935 Stores Equipment	323,279.08		323,279.08
1940 Tools, Shop and Garage Equipment	2,081,941.57		2,081,941.57
1945 Measurement and Testing Equipment	204,006.18		204,006.18
1955 Communication Equipment	1,140,928.54		1,140,928.54
1960 Miscellaneous Equipment	72,951.31		72,951.31
1980 System Supervisory Equipment	128,960.64		128,960.64
1995 Contributions and Grants - Credit	(20,591,344.22)		(20,591,344.22)
2005 Property Under Capital Leases	143,036.00		143,036.00
2060 Electric Plant Acquisition Adjustment	142,276.60		142,276.60
2065 Other Electric Plant Adjustment	0.00	45,509,515.44	45,509,515.44
2105 Accumulated Amortization of Electric Utility-Plant	(129,361,542.40)		(129,361,542.40)
2120 Accumulated Amortization of Electric Utility Plant-Intangibles	(4,040,599.15)		(4,040,599.15)
2140 Accumulated Amortization of Electric Plant	(142,276.60)		(142,276.60)
2160 Accumulated Amortization of Other Utility Plant	0.00	(32,900,835.62)	(32,900,835.62)
2205 Accounts Payable	(20,358,181.02)		(20,358,181.02)
2210 Current portion of Customer deposits	(1,495,704.05)		(1,495,704.05)
2240 Accounts Payable to Associated Companies	(7,354.50)		(7,354.50)
2250 Debt Retirement Charges DRC payable	(722,233.97)		(722,233.97)
2260 Current Portion of Long Term Debt	(1,420,497.90)		(1,420,497.90)
2290 Commodity Taxes	1,445,992.62		1,445,992.62
2292 Payroll Deductions/Expenses Payable	(1,467.90)		(1,467.90)
2294 Accrual for Taxes,"Payments in Lieu"of Taxes	306,278.20		306,278.20
2296 Future Income Taxes - Current	0.00		0.00
2306 Employee Future Benefits	(2,504,100.00)		(2,504,100.00)
2310 Vested Sick Leave Liability	(52,227.84)		(52,227.84)
2320 Other Miscellaneous Non-current liabilities	(37,334.17)		(37,334.17)
2350 Future Income Tax - Non Current	(1,480,008.00)		(1,480,008.00)
2405 Other Regulatory Liabilities	(763,937.00)	(142,183.33)	(906,120.33)
2425 Other Deferred Credits	(830,673.09)		(830,673.09)
2525 Term Bank Loans-long term Portion	(34,441,571.78)		(34,441,571.78)
2550 Advances from Associated Companies	(25,605,089.72)		(25,605,089.72)
3005 Common Shares Issued	(31,245,882.02)		(31,245,882.02)
3010 Contributed Surplus	0.00	(18,753,902.09)	(18,753,902.09)
3040 Appropriated Retained Earnings	(33,207,788.42)	5,056,362.09	(28,151,426.33)
3046 Balance Transferred from Income	(5,326,187.08)	1,088,860.18	(4,237,326.90)
3047 Appropriations of Retained Earnings - current	(6,705,305.00)		(6,705,305.00)
3049 Dividends payable - Common Shares	1,200,000.00		1,200,000.00
Balance Sheet	(0.00)	(0.00)	(0.00)
4006 Residential Energy Sales	(44,390,303.90)		(44,390,303.90)
4010 Commercial Energy Sales	(13,901,587.88)		(13,901,587.88)
4025 Streetlighting energy sales	(720,694.26)		(720,694.26)
4030 Sentinel Lighting Energy Sales	(20,553.99)		(20,553.99)
4035 General Energy Sales	(68,138,892.37)		(68,138,892.37)
4062 Billed WMS	(7,176,971.28)		(7,176,971.28)
4066 Billed NW	(9,441,201.42)		(9,441,201.42)
4068 Billed CN	(6,041,559.12)		(6,041,559.12)
4075 Billed - LV	(524,910.03)		(524,910.03)
4076 Billed SME Charge	(497,847.33)		(497,847.33)
4080 Distribution Services Revenue	(29,280,939.56)	2,970,479.02	(26,310,460.54)
4082 Retail Services Revenue	(38,566.40)		(38,566.40)
4084 Service Transaction Requests (STR) Revenues	(653.00)		(653.00)
4086 SSS Admin Charge	(149,441.11)		(149,441.11)
4215 Other Utility Operating Income	(57,931.59)		(57,931.59)
4225 Late Payment Charges	(424,468.10)		(424,468.10)
4235 Miscellaneous Service Revenues	(1,428,148.99)		(1,428,148.99)
4305 Regulatory Debits	0.00		0.00
4310 Regulatory Credits	0.00		0.00

	Filed RRR excluding FMV entry	Adjustments for FMV entry presentation on FS	Audited Financial Statement December 2015
4355 Gain on Disposition of Utility and Other Property	(29,600.00)		(29,600.00)
4375 Revenues from Non-Utility Operations	(3,100,130.29)		(3,100,130.29)
4380 Expenses from Non-Utility Operations	2,821,817.52		2,821,817.52
4390 Miscellaneous Non-Operating Income	(103,532.00)		(103,532.00)
4405 Interest and Dividend Income	(180,679.95)	75,048.90	(105,631.05)
4705 Power Purchased	76,950,762.62	(4,231,181.81)	72,719,580.81
4707 Global adjustment purchased	50,212,491.26		50,212,491.26
4708 Charges -WMS	7,176,467.19		7,176,467.19
4714 Charges -NW	9,440,558.57		9,440,558.57
4716 Charges -CN	6,041,117.94		6,041,117.94
4750 Charges - LV	524,910.03		524,910.03
4751 Charges - SME	497,847.33		497,847.33
5005 Operation Supervision and Engineering	935,223.10		935,223.10
5010 Load Dispatching	34,680.28		34,680.28
5012 Station Buildings and fixtures expense	51,354.90		51,354.90
5014 Transformer Station Equipment - Operation Labour	30,415.48		30,415.48
5015 Transformer Station Equipment - Operation	191,084.31		191,084.31
5020 Overhead Distribution Lines and Feeders -Labour	221,646.72		221,646.72
5025 Overhead Distribution Lines and Feeders - Operation expenses	76,219.57		76,219.57
5040 Underground Distribution Lines and Feeders Labour	117,703.72		117,703.72
5045 Underground Distribution Lines and Feeders - expenses	326,712.87		326,712.87
5055 Underground Distribution Transformers - Operation	271.84		271.84
5065 Meter Expense	469,026.05		469,026.05
5070 Customer Premises - Operation Labour	124,059.16		124,059.16
5085 Miscellaneous Distribution Expenses	1,732,082.80		1,732,082.80
5105 Maintenance Supervision and Engineering	525,742.03		525,742.03
5114 Maintenance of Distribution Station Equipment	12,381.19		12,381.19
5120 Maintenance of Poles, Towers and Fixtures	88,323.22		88,323.22
5125 Maintenance of Overhead Conductors and Devices	781,873.64		781,873.64
5130 Maintenance of Overhead Services	166,257.87		166,257.87
5135 Overhead Distribution Lines and Feeders - Right of Way	291,160.91		291,160.91
5145 Maintenance of Underground Conduit	39,937.83		39,937.83
5150 Maintenance of Underground Conductors & Devices	226,672.07		226,672.07
5155 Maintenance of Underground Services	121,575.68		121,575.68
5160 Maintenance of Line Transformers	91,430.31		91,430.31
5175 Maintenance of Meters	427.15		427.15
5305 Supervision	998,224.01		998,224.01
5310 Meter Reading Expense	496,222.07	(43,760.00)	452,462.07
5315 Customer Billing	2,711,004.73		2,711,004.73
5320 Collecting	554,044.62		554,044.62
5325 Collecting - Cash Over and Short	137.67		137.67
5335 Bad Debt Expense	285,114.67		285,114.67
5340 Miscellaneous Customer Accounts Expense	238,462.53	67,497.35	305,959.88
5410 Community Relations - Sundry	82,819.02	40,950.00	123,769.02
5605 Executive Salaries and Expenses	431,247.11		431,247.11
5610 Management Salaries and Expenses	2,124,474.07	(29,805.37)	2,094,668.70
5615 General Administrative Salaries and Expenses	464,011.73		464,011.73
5620 Office Supplies and Expenses	78,511.44		78,511.44
5630 Outside Services Employed	55,995.00		55,995.00
5635 Property Insurance	282,015.69		282,015.69
5655 Regulatory Expenses	243,901.76		243,901.76
5665 Miscellaneous General Expense	103,471.65		103,471.65
5675 Maintenance of General Plant	725,448.89		725,448.89
5705 Amortization Expense - Property Plant and Equipment	6,099,693.66		6,099,693.66
5715 Amortization of Intangibles and Other Electric	0.00	1,088,860.18	1,088,860.18
6005 Interest on Long Term Debt	1,138,961.06		1,138,961.06
6030 Interest on Debt to Associated Companies	1,362,190.68		1,362,190.68
6035 Other Interest Expense	856,629.18	(833,510.91)	23,118.27
6105 Taxes other that Income Taxes	264,021.59		264,021.59
6110 Income Taxes	859,182.50		859,182.50
6115 Provision for Future Income Taxes	(533,645.00)	1,401,526.00	867,881.00
6205 Donations	78,050.00	(40,950.00)	37,100.00

	Filed RRR excluding FMV entry	**Adjustments for FMV entry presentation on FS**	**Audited Financial Statement December 2015**
Net movement in regulatory balances, net of tax	0.00	623,706.82	623,706.82
Income Statement total	**(5,326,187.08)**	**1,088,860.18**	**(4,237,326.90)**

Trial Balance Summary			
Revenues	(182,826,795.05)	3,045,527.92	(179,781,267.13)
Expenses	177,500,607.97	(1,956,667.74)	175,543,940.23
(Profit)/Loss	(5,326,187.08)	1,088,860.18	(4,237,326.90)
Net Assets	296,512,378.19	142,183.33	296,654,561.52
Net Liabilities and Equity	(296,512,378.19)	(142,183.33)	(296,654,561.52)
IS (Profit)/Loss	(5,326,187.08)	1,088,860.18	(4,237,326.90)
Balance Sheet (profit)/Loss	(5,326,187.08)	1,088,860.18	(4,237,326.90)

Niagara Peninsula Energy Inc.
FMV Bump
2.1.13

Balance Sheet

		2007 FMV entry	Entry hits Retained Earnings	2007 FMV entry summary	2008	2009	2010	2011	2012	2013	2014	2015	
1	PWU AR PWPower	(216,069.30)	216,069.30										
1	Due from PW power	1,400,000.00	(1,400,000.00)										
1	Future PILS	(5,168,552.00)	5,168,552.00										
1	Inventory	7,684.34	(7,684.34)										
	Fixed assets Total FMV Bump	45,735,559.44		45,735,559.44	45,735,559.44	45,735,559.44	45,735,559.44						
	Adjustment for PW software				-	-	(226,044.00)						
							45,509,515.44	45,509,515.44	45,509,515.44	45,509,515.44	45,509,515.44	45,509,515.44	
	Accum Deprec Total FMV Bump	(24,083,153.39)		(24,083,153.39)	(24,083,153.39)	(25,239,221.08)	(26,348,210.08)	(27,355,968)	(28,442,637)	(29,580,061)	(30,712,338)	(31,811,977)	
	Adjustment for PW software						226,044						
	Current year depreciation				(1,156,068)	(1,108,989)	(1,233,802)	(1,086,669)	(1,137,424)	(1,132,277)	(1,099,638)	(1,088,860)	
					(25,239,221)	(26,348,210)	(27,355,968)	(28,442,637)	(29,580,061)	(30,712,338)	(31,811,977)	(32,900,837)	
	Contributed Surplus	(18,753,902.09)		(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	
1	Retained Earnings	1,078,433.00	(1,078,433.00)	-									
sum of 1's	Retained Earnings net adjustment		(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	
	Cummulative impact on RE for Depreciation FMV bump				1,156,068	2,265,057	3,498,859	3,498,859	4,585,528	5,722,952	6,855,229	7,954,867	5,056,363.23
	Depreciation expense to be closed to Cummulative impact on RE							1,086,669	1,137,424	1,132,277	1,099,638	1,088,860	
	Net	(0.00)	-	-	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	-	-	-	

Income Statement

	2008	2009	2010	2011	2012	2013	2014	2015
Depreciation expense FMV bump	1,156,068	1,111,638	1,233,802	1,086,669	1,137,424	1,132,277	1,099,638	1,088,860
Adjust depreciation expense FMV bump	0	-2649	0	0	0			
	1,156,068	1,108,989	1,233,802	1,086,669	1,137,424	1,132,277	1,099,638	1,088,860

Niagara Peninsula Energy Inc.
For the Twelve Months Ending December 31, 2014

RRR Part 1
Trial Balance Mapped to Financial Statement Grouping
2.1.13

	RRR = Financial Statements December 2014	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry and Water and PILS	RRR filed restated for Regulatory	IFRS vs CGAAP 2014 adjustments	Balance Sheet restated for Regulatory	Presentation Adjustment IFRS	Audited Balance Sheet	Balance Sheet restated for Regulatory	Audited Balance Sheet
1005 Cash	10,590,260.81				10,590,260.81		10,590,260.81		10,590,260.81		
1010 Cash Advance and Working Funds	2,074.63	10,592,335.44			2,074.63		2,074.63		2,074.63	10,592,335.44	
1100 Custom Accounts Receivable	10,937,580.39				10,937,580.39	1,076,761.00	12,014,341.39		12,014,341.39		
1104 Accounts Receivable - Recoverable Work	1,325,306.05				1,325,306.05		1,325,306.05		1,325,306.05		
1110 Other Accounts Receivable	644,069.07				644,069.07		644,069.07		644,069.07		
1130 Accumulated Provision for Uncollectible Accts	(496,230.89)	12,410,724.62			(496,230.89)		(496,230.89)		(496,230.89)	13,487,485.62	
1120 Accrued Utility Revenues	16,220,588.40	16,220,588.40			16,220,588.40	241,936.00	16,462,524.40		16,462,524.40	16,462,524.40	
1200 Accounts Receivable from Associated Companies	5,851.00	5,851.00			5,851.00	0.00	5,851.00		5,851.00	5,851.00	
2294 Accrual for Taxes,"Payments in Lieu"of Taxes	1,061,928.70	1,061,928.70			1,061,928.70		1,061,928.70		1,061,928.70	1,061,928.70	
1180 Prepayments	766,333.27				766,333.27		766,333.27		766,333.27		
1606 Organization	1,926.45	768,259.72			1,926.45		1,926.45		1,926.45	768,259.72	
1330 Plant Materials and Operating Supplies	1,481,013.21	1,481,013.21	42,540,701.09		1,481,013.21		1,481,013.21		1,481,013.21	1,481,013.21	
1705 Land	82,347.02				82,347.02		82,347.02		82,347.02		
1708 Buildings and Fixtures	3,693,130.15				3,693,130.15		3,693,130.15		3,693,130.15		
1715 Station Equipment	2,742,786.83				2,742,786.83		2,742,786.83		2,742,786.83		
1735 Underground Conduit	1,090.59				1,090.59		1,090.59		1,090.59		
1740 Underground Conductors and Devices	138,793.40				138,793.40		138,793.40		138,793.40		
1805 Land	424,925.77				424,925.77		424,925.77		424,925.77		
1806 Land Rights	1,604,396.58				1,604,396.58	(1,604,396.58)	0.00		0.00		
1808 Buildings and Fixtures	111,638.13				111,638.13		111,638.13		111,638.13		
1815 Transformer Station Equipment - Normally Primary	75,622.38				75,622.38		75,622.38		75,622.38		
1820 Distribution Station Equipment - Normally Primary	6,867,625.70				6,867,625.70		6,867,625.70		6,867,625.70		
1830 Poles, Towers and Fixtures	45,208,940.44				45,208,940.44		45,208,940.44		45,208,940.44		
1835 Overhead Conductors and Devices	30,044,276.65				30,044,276.65		30,044,276.65		30,044,276.65		
1840 Underground Conduit	10,359,257.73				10,359,257.73		10,359,257.73		10,359,257.73		
1845 Underground Conductors and Devices	69,349,613.78				69,349,613.78	(514,209.18)	68,835,404.60		68,835,404.60		
1850 Line Transformers	38,491,416.02				38,491,416.02		38,491,416.02		38,491,416.02		
1855 Services	6,275,832.36				6,275,832.36		6,275,832.36		6,275,832.36		
1860 Meters	9,397,062.63				9,397,062.63		9,397,062.63		9,397,062.63		
1865 Other Installations on Customer's Premises	439.87				439.87		439.87		439.87		
1875 Street Lighting and Signal Systems	21,835.21				21,835.21		21,835.21		21,835.21		
1905 Land	508,969.83				508,969.83		508,969.83		508,969.83		
1908 Buildings and Fixtures	16,730,502.84				16,730,502.84		16,730,502.84		16,730,502.84		
1910 Leasehold Improvements	120,252.32				120,252.32		120,252.32		120,252.32		
1915 Office Furniture and Equipment	1,670,223.59				1,670,223.59		1,670,223.59		1,670,223.59		
1920 Computer Equipment-Hardware	4,057,105.13				4,057,105.13		4,057,105.13		4,057,105.13		
1925 Computer Software	3,229,308.26				3,229,308.26	(3,229,308.26)	0.00		0.00		
1930 Transportation Equipment	8,790,945.97				8,790,945.97		8,790,945.97		8,790,945.97		
1935 Stores Equipment	268,477.88				268,477.88		268,477.88		268,477.88		
1940 Tools, Shop and Garage Equipment	2,015,322.46				2,015,322.46		2,015,322.46		2,015,322.46		
1945 Measurement and Testing Equipment	204,006.18				204,006.18		204,006.18		204,006.18		
1955 Communication Equipment	1,075,265.93				1,075,265.93		1,075,265.93		1,075,265.93		
1960 Miscellaneous Equipment	72,951.31				72,951.31		72,951.31		72,951.31		
1980 System Supervisory Equipment	128,960.64				128,960.64		128,960.64		128,960.64		
1995 Contributions and Grants - Credit	(22,904,531.33)				(22,904,531.33)	7,300,157.36	(15,604,373.97)	15,604,373.97	0.00		
2005 Property Under Capital Leases	143,036.00				143,036.00		143,036.00		143,036.00		
2060 Electric Plant Acquisition Adjustment	142,276.60				142,276.60		142,276.60		142,276.60		
2065 Other Electric Plant Adjustment	45,509,515.44			(45,509,515.44)	0.00		0.00	45,509,515.44	45,509,515.44		
2105 Accumulated Amortization of Electric Utility-Plant	(120,788,373.59)				(120,788,373.59)	(3,424,983.72)	(124,213,357.31)		(124,213,357.31)		
2140 Accumulated Amortization of Electric Plant	(142,276.60)				(142,276.60)		(142,276.60)		(142,276.60)		
2160 Accumulated Amortization of Other Utility Plant	(31,811,975.56)	133,910,994.54	133,910,994.54	31,811,975.56	0.00		0.00	(31,189,978.82)	(31,189,978.82)	148,664,624.87	
1611 Computer Software	0.00				0.00	1,604,396.58	1,604,396.58		1,604,396.58		
1612 Land Rights	0.00				0.00	3,229,308.26	3,229,308.26		3,229,308.26		
2120 Accumulated Amortization of Electric Utility Plant-Intangi	0.00				0.00	(3,784,156.10)	(3,784,156.10)	(621,996.74)	(4,406,152.84)	427,552.00	192,951,574.96
1495 Other Assets and Deferred Charges	0.00				0.00	0.00	0.00	3,128,872.76	3,128,872.76		
1550 Hydro One Low Voltage Variance	0.00				0.00		0.00	174,128.27	174,128.27		
1551 Smart Metering Entity Variance	0.00				0.00		0.00	27,319.06	27,319.06		
1576 Accounting Changes Under CGAAP	0.00				0.00		0.00		0.00		
1580 RSVA - WMS	0.00				0.00		0.00		0.00		
1582 RSVA - One Time	0.00				0.00		0.00		0.00		
1584 RSVA - NW	0.00				0.00		0.00	992,790.88	992,790.88		
1586 RSVA - CN	0.00				0.00		0.00	727,844.84	727,844.84		
1588 RSVA - Power	0.00				0.00		0.00	2,333,559.20	2,333,559.20		
1588 RSVA - GA Non-RPP	0.00				0.00		0.00	4,425,150.65	4,425,150.65		
1518 RCVA - Retail	0.00				0.00		0.00	159,225.32	159,225.32		
1548 RCVA - STR	0.00				0.00		0.00	230,883.45	230,883.45		
1508 Other Regulatory Assets	0.00				0.00		0.00	27,767.71	27,767.71		
1562 Deferred Payments in Lieu of taxes	0.00				0.00		0.00		0.00		
1563 Deferred PILS contra Account	0.00				0.00		0.00		0.00		
1535 Smart Grid Deferral Account	0.00				0.00		0.00	18,720.96	18,720.96		
1555 Smart Meter Capital and Recovery Variance	0.00				0.00		0.00	1,295,154.75	1,295,154.75		
1556 Smart Meter OM&A Variance	0.00				0.00		0.00	(11,450.57)	(11,450.57)		
1521 Special Purpose Charge	0.00				0.00		0.00		0.00		
1595 Disposition and Recovery of Regulatory Balances	0.00	0.00			0.00		0.00		0.00	13,529,967.28	13,529,967.28

	RRR = Financial Statements December 2014	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry and Water and PILS	RRR filed restated for Regulatory	IFRS vs CGAAP 2014 adjustments	Balance Sheet restated for Regulatory	Presentation Adjustment IFRS	Audited Balance Sheet	Balance Sheet restated for Regulatory	Audited Balance Sheet
2296 Future Income Taxes - Current	1,204,168.40	1,204,168.40	1,204,168.40		1,204,168.40	(1,204,168.40)	0.00		0.00		
2205 Accounts Payable	(19,711,631.87)				(19,711,631.87)	(726,570.00)	(20,438,201.87)	(612,127.00)	(21,050,328.87)		
2220 Miscellaneous Current and Accrued Liabilities	0.00				0.00		0.00		0.00		
2250 Debt Retirement Charges DRC payable	(759,130.32)				(759,130.32)		(759,130.32)		(759,130.32)		
2290 Commodity Taxes	1,466,742.24				1,466,742.24		1,466,742.24		1,466,742.24		
2292 Payroll Deductions/Expenses Payable	(1,469.06)				(1,469.06)		(1,469.06)		(1,469.06)	(20,344,186.01)	
2425 Other Deferred Credits	(520,752.92)	(19,526,241.93)			(520,752.92)	64,195.57	(456,557.35)		(456,557.35)	(456,557.35)	
2210 Current portion of Customer deposits	(728,569.49)	(728,569.49)			(728,569.49)	(728,569.49)	(1,457,138.98)	(37,334.17)	(1,494,473.15)	(1,494,473.15)	
2240 Accounts Payable to Associated Companies	(23,574.89)	(23,574.89)			(23,574.89)	0.00	(23,574.89)		(23,574.89)	(23,574.89)	
2260 Current Portion of Long Term Debt	(3,515,074.97)	(3,515,074.97)	(23,793,461.28)		(3,515,074.97)		(3,515,074.97)		(3,515,074.97)	(3,515,074.97)	
2520 Other Long Term debt	0.00				0.00		0.00		0.00		
2525 Term Bank Loans-long term Portion	(33,724,569.68)				(33,724,569.68)		(33,724,569.68)		(33,724,569.68)		
2550 Advances from Associated Companies	(25,605,089.72)	(59,329,659.40)			(25,605,089.72)		(25,605,089.72)		(25,605,089.72)	(59,329,659.40)	
2320 Other Miscellaneous Non-current liabilities	(37,334.17)				(37,334.17)		(37,334.17)	37,334.17	0.00		
2335 Long Term Customer Deposits	(728,569.49)	(765,903.66)			(728,569.49)	728,569.49	0.00		0.00	0.00	
2310 Vested Sick Leave Liability	(50,135.10)	(50,135.10)			(50,135.10)		(50,135.10)		(50,135.10)	(50,135.10)	
2306 Employee Future Benefits	(3,907,283.00)	(3,907,283.00)			(3,907,283.00)	1,505,102.00	(2,402,181.00)		(2,402,181.00)	(2,402,181.00)	
1995 Contributions and Grants - Credit	0.00				0.00	0.00	0.00	(15,604,373.97)	(15,604,373.97)	(15,604,373.97)	
2350 Future Income Tax - Non Current	0.00				0.00	(612,127.00)	(612,127.00)		(612,127.00)	(612,127.00)	(103,832,342.84)
1495 Other Assets and Deferred Charges	0.00				0.00	2,064,621.75	2,064,621.75	(2,516,745.76)	(452,124.01)		
1550 Hydro One Low Voltage Variance	174,128.27				174,128.27		174,128.27	(174,128.27)	0.00		
1551 Smart Metering Entity Variance	27,319.06				27,319.06		27,319.06	(27,319.06)	0.00		
1576 Accounting Changes Under CGAAP	(6,169,896.00)				(6,169,896.00)		(6,169,896.00)		(6,169,896.00)		
1580 RSVA - WMS	(1,300,556.42)				(1,300,556.42)		(1,300,556.42)		(1,300,556.42)		
1582 RSVA - One Time	0.00				0.00		0.00		0.00		
1584 RSVA - NW	992,790.88				992,790.88		992,790.88	(992,790.88)	0.00		
1586 RSVA - CN	727,844.84				727,844.84		727,844.84	(727,844.84)	0.00		
1588 RSVA - Power	(4,741,791.38)				(4,741,791.38)		(4,741,791.38)	(2,333,559.20)	(7,075,350.58)		
1588 RSVA - GA Non-RPP	4,425,150.65				4,425,150.65		4,425,150.65	(4,425,150.65)	0.00		
1518 RCVA - Retail	159,225.32				159,225.32		159,225.32	(159,225.32)	0.00		
1548 RCVA - STR	230,883.45				230,883.45		230,883.45	(230,883.45)	0.00		
1508 Other Regulatory Assets	27,767.71				27,767.71	(1,570,621.00)	(1,542,853.29)	(27,767.71)	(1,570,621.00)		
1562 Deferred Payments in Lieu of taxes	0.00				0.00		0.00		0.00		
1563 Deferred PILS contra Account	0.00				0.00		0.00		0.00		
1535 Smart Grid Deferral Account	18,720.96				18,720.96		18,720.96	(18,720.96)	0.00		
1555 Smart Meter Capital and Recovery Variance	1,295,154.75				1,295,154.75		1,295,154.75	(1,295,154.75)	0.00		
1556 Smart Meter OM&A Variance	(11,450.57)				(11,450.57)		(11,450.57)	11,450.57	0.00		
1521 Special Purpose Charge	0.00				0.00		0.00		0.00		
1595 Disposition and Recovery of Regulatory Balances	(1,224,135.95)	(5,368,844.43)	(69,421,825.59)		(1,224,135.95)		(1,224,135.95)		(1,224,135.95)	(17,792,683.96)	(17,792,683.96)
3005 Common Shares Issued	(31,245,882.02)	(31,245,882.02)			(31,245,882.02)		(31,245,882.02)		(31,245,882.02)	(31,245,882.02)	(31,245,882.02)
3010 Contributed Surplus	(18,753,902.09)			18,753,902.09	0.00		0.00	(18,753,902.09)	(18,753,902.09)		
3047 Appropriations of Retained Earnings - current	(6,705,305.00)	(25,459,207.09)			(6,705,305.00)		(6,705,305.00)		(6,705,305.00)	(25,459,207.09)	(25,459,207.09)
3040 Appropriated Retained Earnings	(26,588,418.98)			(3,956,723.81)	(29,912,617.79)	(443,438.94)	(30,356,056.73)	3,956,723.81	(26,399,332.92)		
3041 Appropriated Retained Earnings				632,525.00			0.00	(632,525.00)	(632,525.00)		
3046 Balance Transferred from Income	(2,347,069.07)			(1,732,163.40)	(4,079,232.47)	27,500.66	(4,051,731.81)	1,732,163.40	(2,319,568.41)		
3049 Dividends payable - Common Shares	1,200,000.00	(27,735,488.05)	(84,440,577.16)		1,200,000.00		1,200,000.00		1,200,000.00	(28,151,426.33)	(28,151,426.33)
Balance Sheet	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**(0.00)**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
4006 Residential Energy Sales	(39,971,818.36)				(39,971,818.36)		(39,971,818.36)		(39,971,818.36)		
4010 Commercial Energy Sales	(12,909,143.22)				(12,909,143.22)		(12,909,143.22)		(12,909,143.22)		
4025 Streetlighting energy sales	(658,175.31)				(658,175.31)		(658,175.31)		(658,175.31)		
4030 Sentinel Lighting Energy Sales	(19,412.15)				(19,412.15)		(19,412.15)		(19,412.15)		
4035 General Energy Sales	(60,216,072.27)	(113,774,621.31)			(60,216,072.27)		(60,216,072.27)		(60,216,072.27)		
4062 Billed WMS	(7,226,114.58)				(7,226,114.58)		(7,226,114.58)		(7,226,114.58)		
4066 Billed NW	(9,158,481.59)				(9,158,481.59)		(9,158,481.59)		(9,158,481.59)		
4068 Billed CN	(5,684,923.09)				(5,684,923.09)		(5,684,923.09)		(5,684,923.09)		
4075 Billed - LV	(518,012.01)				(518,012.01)		(518,012.01)		(518,012.01)		
4076 Billed SME Charge	(484,344.35)	(23,071,875.62)			(484,344.35)		(484,344.35)		(484,344.35)	(136,846,496.93)	(136,846,496.93)
4080 Distribution Services Revenue	(30,261,924.91)	(30,261,924.91)		(632,525.00)	(30,894,449.91)		(30,894,449.91)	5,431,616.00	(25,462,833.91)		
4082 Retail Services Revenue	(41,658.40)				(41,658.40)		(41,658.40)		(41,658.40)		
4084 Service Transaction Requests (STR) Revenues	(970.50)	(42,628.90)			(970.50)		(970.50)		(970.50)		
4086 SSS Admin Charge	(144,761.88)	(144,761.88)	(167,295,812.62)		(144,761.88)		(144,761.88)		(144,761.88)	(25,650,224.69)	(25,650,224.69)
4215 Other Utility Operating Income	0.00				0.00		0.00	(60,586.30)	(60,586.30)		
4225 Late Payment Charges	0.00				0.00		0.00	(405,422.43)	(405,422.43)		
4355 Gain on Disposition of Utility and Other Property	0.00				0.00		0.00	(8,500.00)	(8,500.00)		
4360 Losses from disposition of Utility and Other Property	0.00				0.00		0.00	0.00	0.00		
4362 Loss on Retirement of Utility and Other Property	0.00				0.00		0.00	0.00	0.00		
4375 Revenues from Non-Utility Operations	0.00				0.00		0.00	(2,921,938.81)	(2,921,938.81)		
4235 Miscellaneous Service Revenues	0.00				0.00		0.00	(1,328,146.59)	(1,328,146.59)		
4380 Expenses from Non-Utility Operations	0.00			0.00	0.00		0.00	2,731,384.20	2,731,384.20		
4390 Miscellaneous Non-Operating Income	0.00				0.00		0.00	(105,335.82)	(105,335.82)		
4405 Interest and Dividend Income	0.00	0.00	0.00		0.00		0.00	0.00	0.00	(2,098,545.75)	(2,098,545.75)

	RRR = Financial Statements December 2014	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry and Water and PILS	RRR filed restated for Regulatory	IFRS vs CGAAP 2014 adjustments	Balance Sheet restated for Regulatory	Presentation Adjustment IFRS	Audited Balance Sheet	Tie At Balance Sheet restated for Regulatory	Audited Balance Sheet
4705 Power Purchased	113,774,621.31				113,774,621.31	(34,343,745.95)	79,430,875.36	135,350.00	79,566,225.36		
4707 Global adjustment purchased	0.00				0.00	34,343,745.95	34,343,745.95		34,343,745.95		
4708 Charges -WMS	7,226,114.58				7,226,114.58		7,226,114.58		7,226,114.58		
4714 Charges -NW	9,158,481.59				9,158,481.59		9,158,481.59		9,158,481.59		
4716 Charges -CN	5,684,923.09				5,684,923.09		5,684,923.09		5,684,923.09		
4751 Charges -SME	518,012.01				518,012.01		518,012.01		518,012.01		
4750 Charges - LV	484,344.35	136,846,496.93	136,846,496.93		484,344.35		484,344.35		484,344.35	136,981,846.93	136,981,846.93
4215 Other Utility Operating Income	(60,586.30)				(60,586.30)		(60,586.30)	60,586.30	0.00		
4225 Late Payment Charges	(405,422.43)				(405,422.43)		(405,422.43)	405,422.43	0.00		
4355 Gain on Disposition of Utility and Other Property	(8,500.00)				(8,500.00)		(8,500.00)	8,500.00	0.00		
4360 Losses from disposition of Utility and Other Property	0.00				0.00		0.00	0.00	0.00		
4362 Loss on Retirement of Utility and Other Property	0.00				0.00		0.00	0.00	0.00		
4375 Revenues from Non-Utility Operations	(2,921,938.81)				(2,921,938.81)		(2,921,938.81)	2,921,938.81	0.00		
4235 Miscellaneous Service Revenues	(813,603.61)				(813,603.61)	(514,542.98)	(1,328,146.59)	1,328,146.59	0.00		
4380 Expenses from Non-Utility Operations	2,731,384.20			106,687.24	2,838,071.44		2,838,071.44	(2,838,071.44)	0.00		
4390 Miscellaneous Non-Operating Income	(105,335.82)				(105,335.82)		(105,335.82)	105,335.82	0.00		
4405 Interest and Dividend Income	(382,671.17)	(1,966,673.94)	(1,966,673.94)		(382,671.17)		(382,671.17)	382,671.17	0.00		
5005 Operation Supervision and Engineering	713,388.73				713,388.73		713,388.73		713,388.73		
5010 Load Dispatching	51,765.11				51,765.11		51,765.11		51,765.11		
5012 Station Buildings and fixtures expense	45,598.81				45,598.81		45,598.81		45,598.81		
5014 Transformer Station Equipment - Operation Labour	20,497.00				20,497.00		20,497.00		20,497.00		
5015 Transformer Station Equipment - Operation	161,483.65				161,483.65		161,483.65		161,483.65		
5020 Overhead Distribution Lines and Feeders -Labour	197,594.29				197,594.29		197,594.29		197,594.29		
5025 Overhead Distribution Lines and Feeders - Operation ex	12,132.28				12,132.28	7,600.00	19,732.28		19,732.28		
5040 Underground Distribution Lines and Feeders Labour	87,469.33				87,469.33		87,469.33		87,469.33		
5045 Underground Distribution Lines and Feeders - expenses	291,703.56				291,703.56		291,703.56		291,703.56		
5055 Underground Distribution Transformer - Operations	241.18				241.18		241.18		241.18		
5065 Meter Expense	474,475.94				474,475.94		474,475.94		474,475.94		
5085 Miscellaneous Distribution Expenses	2,114,542.20				2,114,542.20		2,114,542.20		2,114,542.20		
5105 Maintenance Supervision and Engineering	492,765.57				492,765.57		492,765.57		492,765.57		
5112 Maintenance of Transformer Station Equipment	0.00				0.00		0.00		0.00		
5114 Maintenance of Distribution Station Equipment	9,701.80				9,701.80		9,701.80		9,701.80		
5120 Maintenance of Poles, Towers and Fixtures	98,453.45				98,453.45		98,453.45		98,453.45		
5125 Maintenance of Overhead Conductors and Devices	769,627.26				769,627.26		769,627.26		769,627.26		
5130 Maintenance of Overhead Services	156,681.03				156,681.03		156,681.03		156,681.03		
5135 Overhead Distribution Lines and Feeders - Right of Way	244,299.92				244,299.92		244,299.92		244,299.92		
5145 Maintenance of Underground Conduit	19,980.47				19,980.47		19,980.47		19,980.47		
5150 Maintenance of Underground Conductors & Devices	242,172.93				242,172.93		242,172.93		242,172.93		
5155 Maintenance of Underground Services	126,178.15				126,178.15		126,178.15		126,178.15		
5160 Maintenance of Line Transformers	176,166.08				176,166.08		176,166.08		176,166.08		
5175 Maintenance of Meters	86,888.07	6,593,806.81			86,888.07	(81,374.74)	5,513.33		5,513.33	6,520,032.07	6,520,032.07
5070 Customer Premises - Operation Labour	126,427.32				126,427.32		126,427.32		126,427.32		
5410 Community Relations - Sundry	79,138.47	205,565.79			79,138.47		79,138.47		79,138.47	205,565.79	205,565.79
5605 Executive Salaries and Expenses	383,246.74				383,246.74		383,246.74		383,246.74		
5610 Management Salaries and Expenses	1,915,052.68			(21,766.25)	1,893,286.43	5,150.00	1,898,436.43	21,766.25	1,920,202.68		
5615 General Administrative Salaries and Expenses	441,954.29				441,954.29		441,954.29		441,954.29		
5620 Office Supplies and Expenses	81,567.70				81,567.70		81,567.70		81,567.70		
5630 Outside Services Employed	40,800.00				40,800.00		40,800.00		40,800.00		
5635 Property Insurance	312,398.70				312,398.70		312,398.70		312,398.70		
5645 Employee Pensions and benefits	0.00				0.00	65,519.00	65,519.00		65,519.00		
5655 Regulatory Expenses	233,003.01				233,003.01		233,003.01		233,003.01		
5665 Miscellaneous General Expense	56,573.58				56,573.58		56,573.58		56,573.58		
5675 Maintenance of General Plant	661,757.10				661,757.10		661,757.10		661,757.10		
6005 Interest on Long Term Debt	979,088.93				979,088.93		979,088.93	(979,088.93)	0.00		
6030 Interest on Debt to Associated Companies	1,362,190.68				1,362,190.68		1,362,190.68	(1,362,190.68)	0.00		
6035 Other Interest Expense	251,148.70				251,148.70		251,148.70	(251,148.70)	0.00		
6105 Taxes other that Income Taxes	259,958.35				259,958.35		259,958.35	0.00	259,958.35		
6215 Penalties	0.00				0.00		0.00		0.00		
6205 Donations	38,906.00	7,017,646.46			38,906.00		38,906.00		38,906.00	4,495,887.15	4,495,887.15
5305 Supervision	1,411,000.30				1,411,000.30		1,411,000.30	(595,496.97)	815,503.33		
5310 Meter Reading Expense	850,229.56				850,229.56	968,556.94	1,818,786.50	(1,445,050.23)	373,736.27		
5315 Customer Billing	2,680,326.38			(78,884.99)	2,601,441.39	(476,493.29)	2,124,948.10	623,124.15	2,748,072.25		
5320 Collecting	495,766.93				495,766.93	(130,292.81)	365,474.12		365,474.12		
5325 Collecting - Cash Over and Short	41.34				41.34		41.34		41.34		
5335 Bad Debt Expense	258,260.69				258,260.69		258,260.69		258,260.69		
5340 Miscellaneous Customer Accounts Expense	242,276.00	5,937,901.20			242,276.00		242,276.00	72,388.00	314,664.00	4,875,752.00	4,875,752.00
5705 Amortization Expense - Property Plant and Equipment	5,649,681.14	5,649,681.14		(6,036.00)	5,643,645.14	600,392.95	6,244,038.09	(50,176.00)	6,193,862.09	6,193,862.09	6,193,862.09
5715 Amortization of Intangibles and Other Electric	1,099,638.40	1,099,638.40		(1,099,638.40)	0.00		0.00	1,099,638.00	1,099,638.00	1,099,638.00	1,099,638.00
			26,504,239.80		0.00		0.00		0.00		
4405 Interest and Dividend Income	0.00				0.00		0.00	(116,333.00)	(116,333.00)	(116,333.00)	(116,333.00)
6005 Interest on Long Term Debt	0.00				0.00		0.00	979,088.93	979,088.93		
6030 Interest on Debt to Associated Companies	0.00				0.00		0.00	1,362,190.68	1,362,190.68		
6105 Taxes other that Income Taxes	0.00				0.00		0.00	14,242.87	14,242.87	2,355,522.48	2,355,522.48
4305 Regulatory Debits	3,115,330.27	3,115,330.27	3,115,330.27		3,115,330.27		3,115,330.27	(3,115,330.27)	0.00	0.00	0.00
6110 Income Taxes	572,867.30				572,867.30		572,867.30		572,867.30		
6115 Provision for Future Income Taxes	(123,516.81)	449,350.49	449,350.49		(123,516.81)	(417,014.41)	(540,531.22)	906,657.22	366,126.00	938,993.30	938,993.30

	RRR = Financial Statements December 2014	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry and Water and PILS	RRR filed restated for Regulatory	IFRS vs CGAAP 2014 adjustments	Balance Sheet restated for Regulatory	Presentation Adjustment IFRS	Audited Balance Sheet	Balance Sheet restated for Regulatory	Audited Balance Sheet
Net movement regulatory							0.00	(1,275,069.00)	(1,275,069.00)	(1,275,069.00)	(1,275,069.00)
Income Statement total	**(2,347,069.07)**	**(2,347,069.07)**	**(2,347,069.07)**	**(1,732,163.40)**	**(4,079,232.47)**	**27,500.66**	**(4,051,731.81)**	**1,732,162.25**	**(2,319,569.56)**	**(2,319,569.56)**	**(2,319,569.56)**
Trial Balance Summary											
Revenues	(169,262,486.56)	(169,262,486.56)	(169,262,486.56)	(525,837.76)	(169,788,324.32)	(514,542.98)	(170,302,867.30)	5,591,266.93	(164,711,600.37)	(164,711,600.37)	(164,711,600.37)
Expenses	166,915,417.49	166,915,417.49	166,915,417.49	(1,206,325.64)	165,709,091.85	542,043.64	166,251,135.49	(3,859,104.68)	162,392,030.81	162,392,030.81	162,392,030.81
(Profit)/Loss	(2,347,069.07)	(2,347,069.07)	(2,347,069.07)	(1,732,163.40)	(4,079,232.47)	27,500.66	(4,051,731.81)	1,732,162.25	(2,319,569.56)	(2,319,569.56)	(2,319,569.56)
Net Assets	278,172,888.61	37,314,096.36	(25,676,956.10)	0.00	278,172,888.61	496,150.94	278,669,039.55	5,203,279.45	283,872,319.00	25,004,785.43	(17,792,683.96)
Net Liabilities and Equity	(278,172,888.61)	(37,314,096.36)	25,676,956.10	0.00	(278,172,888.61)	(496,150.94)	(278,669,039.55)	(5,203,279.45)	(283,872,319.00)	(25,004,785.43)	17,792,683.96
IS (Profit)/Loss	(2,347,069.07)	(2,347,069.07)	(2,347,069.07)	(1,732,163.40)	(4,079,232.47)	27,500.66	(4,051,731.81)	1,732,162.25	(2,319,569.56)	(2,319,569.56)	(2,319,569.56)
Balance Sheet (profit)/Loss	(2,347,069.07)	(2,347,069.07)	(2,347,069.07)	(1,732,163.40)	(4,079,232.47)	27,500.66	(4,051,731.81)	1,732,163.40	(2,319,568.41)	(2,319,568.41)	(2,319,568.41)

Niagara Peninsula Energy Inc.
· the Twelve Months Ending December 31, 2014 IFRS vs CGAAP
RRR Part 2
Trial Balance by Account
2.1.13

	Original Filed CGAAP 2014 after removal of FMV)	Originally filed Adjustment for FMV entry and Water and PILS	Original Filed CGAAP 2014	IFRS vs CGAAP 2014 adjustments	Restated IFRS 2014
Current Assets					
1005 Cash	10,590,260.81		10,590,260.81	-	10,590,260.81
1010 Cash Advance and Working Funds	2,074.63		2,074.63	-	2,074.63
1100 Custom Accounts Receivable	10,937,580.39		10,937,580.39	1,076,760.64	12,014,341.03
1104 Accounts Receivable - Recoverable Work	1,325,306.05		1,325,306.05	-	1,325,306.05
1110 Other Accounts Receivable	644,069.07		644,069.07	-	644,069.07
1120 Accrued Utility Revenues	16,220,588.40		16,220,588.40	241,935.59	16,462,523.99
1130 Accumulated Provision for Uncollectible Accts	(496,230.89)		(496,230.89)	-	(496,230.89)
1180 Prepayments	766,333.27		766,333.27	-	766,333.27
1200 Account Receivable from Associated companies	5,851.00		5,851.00	-	5,851.00
1330 Plant Materials and Operating Supplies	1,481,013.21		1,481,013.21	-	1,481,013.21
1495 Other Assets and Deferred Charges	-		-	2,064,621.75	2,064,621.75
1508 Other Regulatory Assets-Lead/Lag Study	-		-	-	-
1508 Other Regulatory Assets-IFRS transition	16,912.26		16,912.26	-	16,912.26
1508 Other Regulatory Assets Incremental Capital Charges Hydro One	10,855.45		10,855.45	-	10,855.45
1508 Other Regulatory Assets - OPEB	-		-	(1,570,621.00)	(1,570,621.00)
1518 RCVA - Retail	159,225.32		159,225.32	-	159,225.32
1535 Smart Grid Deferral Account	18,720.96		18,720.96	-	18,720.96
1548 RCVA - STR	230,883.45		230,883.45	-	230,883.45
1550 Hydro One Low Voltage Variance	174,128.27		174,128.27	-	174,128.27
1551 Smart Metering Entity Variance	27,319.06		27,319.06	-	27,319.06
1555 Smart Meter Capital and Recovery Variance	1,295,154.75		1,295,154.75	(11,450.57)	1,283,704.18
1556 Smart Meter OM&A Variance	(11,450.57)		(11,450.57)	11,450.57	-
1557 Mist meter variance	-		-	-	-
1568 LRAM variance	-		-	-	-
1576 Accounting Changes Under CGAAP	(6,169,896.00)		(6,169,896.00)	-	(6,169,896.00)
1580 RSVA - WMS	(1,300,556.42)		(1,300,556.42)	-	(1,300,556.42)
1584 RSVA - NW	992,790.88		992,790.88	-	992,790.88
1586 RSVA - CN	727,844.84		727,844.84	-	727,844.84
1588 RSVA - Power	(4,741,791.38)		(4,741,791.38)	-	(4,741,791.38)
1589 RSVA - GA Non-RPP	4,425,150.65		4,425,150.65	-	4,425,150.65
1595 Disposition and Recovery of Regulatory Balances	(1,224,135.95)		(1,224,135.95)	-	(1,224,135.95)
1606 Organization	1,926.45		1,926.45	-	1,926.45
1611 Computer Software	-		-	3,229,308.26	3,229,308.26
1612 Land Rights	-		-	1,604,396.58	1,604,396.58
1705 Land	82,347.02		82,347.02	-	82,347.02
1708 Buildings and Fixtures	3,693,130.15		3,693,130.15	-	3,693,130.15
1715 Station Equipment	2,742,786.83		2,742,786.83	-	2,742,786.83
1735 Underground Conduit	1,090.59		1,090.59	-	1,090.59
1740 Underground Conductors and Devices	138,793.40		138,793.40	-	138,793.40
1805 Land	424,925.77		424,925.77	-	424,925.77
1806 Land Rights	1,604,396.58		1,604,396.58	(1,604,396.58)	-
1808 Buildings and Fixtures	111,638.13		111,638.13	-	111,638.13
1815 Transformer Station Equipment - Normally Primary	75,622.38		75,622.38	-	75,622.38
1820 Distribution Station Equipment - Normally Primary	6,867,625.70		6,867,625.70	-	6,867,625.70
1830 Poles, Towers and Fixtures	45,208,940.44		45,208,940.44	-	45,208,940.44

	Original Filed CGAAP 2014 after removal of FMV)	Adjustment for FMV entry and Water and PILS	Original Filed CGAAP 2014	IFRS vs CGAAP 2014 adjustments	Restated IFRS 2014
1835 Overhead Conductors and Devices	30,044,276.65		30,044,276.65	-	30,044,276.65
1840 Underground Conduit	10,359,257.73		10,359,257.73	-	10,359,257.73
1845 Underground Conductors and Devices	69,349,613.78		69,349,613.78	(514,209.18)	68,835,404.60
1850 Line Transformers	38,491,416.02		38,491,416.02	-	38,491,416.02
1855 Services	6,275,832.36		6,275,832.36	-	6,275,832.36
1860 Meters	9,397,062.63		9,397,062.63	-	9,397,062.63
1865 Other Installations on Customer's Premises	439.87		439.87	-	439.87
1875 Street Lighting and Signal Systems	21,835.21		21,835.21	-	21,835.21
1905 Land	508,969.83		508,969.83	-	508,969.83
1908 Buildings and Fixtures	16,730,502.84		16,730,502.84	-	16,730,502.84
1910 Leasehold Improvements	120,252.32		120,252.32	-	120,252.32
1915 Office Furniture and Equipment	1,670,223.59		1,670,223.59	-	1,670,223.59
1920 Computer Equipment-Hardware	4,057,105.13		4,057,105.13	-	4,057,105.13
1925 Computer Software	3,229,308.26		3,229,308.26	(3,229,308.26)	-
1930 Transportation Equipment	8,790,945.97		8,790,945.97	-	8,790,945.97
1935 Stores Equipment	268,477.88		268,477.88	-	268,477.88
1940 Tools, Shop and Garage Equipment	2,015,322.46		2,015,322.46	-	2,015,322.46
1945 Measurement and Testing Equipment	204,006.18		204,006.18	-	204,006.18
1955 Communication Equipment	1,075,265.93		1,075,265.93	-	1,075,265.93
1960 Miscellaneous Equipment	72,951.31		72,951.31	-	72,951.31
1980 System Supervisory Equipment	128,960.64		128,960.64	-	128,960.64
1995 Contributions and Grants - Credit	(22,904,531.33)		(22,904,531.33)	7,300,157.36	(15,604,373.97)
2005 Property Under Capital Leases	143,036.00		143,036.00	-	143,036.00
2060 Electric Plant Acquisition Adjustment	142,276.60		142,276.60	-	142,276.60
2065 Other Electric Plant Adjustment	45,509,515.44	(45,509,515.44)	-		-
2105 Accumulated Amortization of Electric Utility-Plant	(120,788,373.59)		(120,788,373.59)	(3,424,983.72)	(124,213,357.31)
2120 Accumulated Amortization of Electric Utility Plant-Intangibles	-		-	(3,784,156.10)	(3,784,156.10)
2140 Accumulated Amortization of Electric Plant	(142,276.60)		(142,276.60)	-	(142,276.60)
2160 Accumulated Amortization of Other Utility Plant	(31,811,975.56)	31,811,975.56	-		-
2205 Accounts Payable	(19,711,631.87)		(19,711,631.87)	(726,569.23)	(20,438,201.10)
2210 Current portion of Customer deposits	(728,569.49)		(728,569.49)	(728,569.49)	(1,457,138.98)
2240 Accounts Payable to Associated Companies	(23,574.89)		(23,574.89)	-	(23,574.89)
2250 Debt Retirement Charges DRC payable	(759,130.32)		(759,130.32)	-	(759,130.32)
2260 Current Portion of Long Term Debt	(3,515,074.97)		(3,515,074.97)	-	(3,515,074.97)
2290 Commodity Taxes	1,466,742.24		1,466,742.24	-	1,466,742.24
2292 Payroll Deductions/Expenses Payable	(1,469.06)		(1,469.06)	-	(1,469.06)
2294 Accrual for Taxes,"Payments in Lieu"of Taxes	1,061,928.70		1,061,928.70	-	1,061,928.70
2296 Future Income Taxes - Current	1,204,168.40		1,204,168.40	(1,204,168.40)	-
2306 Employee Future Benefits	(3,907,283.00)		(3,907,283.00)	1,505,102.00	(2,402,181.00)
2310 Vested Sick Leave Liability	(50,135.10)		(50,135.10)	-	(50,135.10)
2320 Other Miscellaneous Non-current liabilities	(37,334.17)		(37,334.17)	-	(37,334.17)
2335 Long Term Customer Deposits	(728,569.49)		(728,569.49)	728,569.49	-
2350 Future Income Tax - Non Current	-		-	(612,127.00)	(612,127.00)
2405 Other Regulatory Liabilities	-		-	-	-
2425 Other Deferred Credits	(520,752.92)		(520,752.92)	64,195.57	(456,557.35)
2525 Term Bank Loans-long term Portion	(33,724,569.68)		(33,724,569.68)	-	(33,724,569.68)
2550 Advances from Associated Companies	(25,605,089.72)		(25,605,089.72)	-	(25,605,089.72)
3005 Common Shares Issued	(31,245,882.02)		(31,245,882.02)	-	(31,245,882.02)
3010 Contributed Surplus	(18,753,902.09)	18,753,902.09	-		-
3040 Appropriated Retained Earnings	(26,588,418.98)	(3,956,723.81)	(30,545,142.79)	(443,438.94)	(30,988,581.73)
3041 Appropriated Retained Earnings	-	632,525.00	632,525.00		632,525.00
3046 Balance Transferred from Income	(2,347,069.07)	(1,732,163.40)	(4,079,232.47)	27,500.66	(4,051,731.81)
3047 Appropriations of Retained Earnings - current	(6,705,305.00)		(6,705,305.00)	-	(6,705,305.00)
3049 Dividends payable - Common Shares	1,200,000.00		1,200,000.00	-	1,200,000.00

	Original Filed CGAAP 2014 after removal of FMV)	Adjustment for FMV entry and Water and PILS	Original Filed CGAAP 2014	IFRS vs CGAAP 2014 adjustments	Restated IFRS 2014
Balance Sheet	0.00	0.00	0.00	(0.00)	0.00
4006 Residential Energy Sales	(39,971,818.36)		(39,971,818.36)	0.00	(39,971,818.36)
4010 Commercial Energy Sales	(12,909,143.22)		(12,909,143.22)	0.00	(12,909,143.22)
4025 Streetlighting energy sales	(658,175.31)		(658,175.31)	0.00	(658,175.31)
4030 Sentinel Lighting Energy Sales	(19,412.15)		(19,412.15)	0.00	(19,412.15)
4035 General Energy Sales	(60,216,072.27)		(60,216,072.27)	0.00	(60,216,072.27)
4062 Billed WMS	(7,226,114.58)		(7,226,114.58)	0.00	(7,226,114.58)
4066 Billed NW	(9,158,481.59)		(9,158,481.59)	0.00	(9,158,481.59)
4068 Billed CN	(5,684,923.09)		(5,684,923.09)	0.00	(5,684,923.09)
4075 Billed - LV	(518,012.01)		(518,012.01)	0.00	(518,012.01)
4076 Billed SME Charge	(484,344.35)		(484,344.35)	0.00	(484,344.35)
4080 Distribution Services Revenue	(30,261,924.91)	(632,525.00)	(30,894,449.91)	0.00	(30,894,449.91)
4082 Retail Services Revenue	(41,658.40)		(41,658.40)	0.00	(41,658.40)
4084 Service Transaction Requests (STR) Revenues	(970.50)		(970.50)	0.00	(970.50)
4086 SSS Admin Charge	(144,761.88)		(144,761.88)	0.00	(144,761.88)
4215 Other Utility Operating Income	(60,586.30)		(60,586.30)	0.00	(60,586.30)
4225 Late Payment Charges	(405,422.43)		(405,422.43)	0.00	(405,422.43)
4235 Miscellaneous Service Revenues	(813,603.61)		(813,603.61)	(514,542.98)	(1,328,146.59)
4305 Regulatory Debits	3,115,330.27		3,115,330.27	0.00	3,115,330.27
4310 Regulatory Credits	-		-	0.00	-
4355 Gain on Disposition of Utility and Other Property	(8,500.00)		(8,500.00)	0.00	(8,500.00)
4375 Revenues from Non-Utility Operations	(2,921,938.81)		(2,921,938.81)	0.00	(2,921,938.81)
4380 Expenses from Non-Utility Operations	2,731,384.20	106,687.24	2,838,071.44	0.00	2,838,071.44
4390 Miscellaneous Non-Operating Income	(105,335.82)		(105,335.82)	0.00	(105,335.82)
4405 Interest and Dividend Income	(382,671.17)		(382,671.17)	0.00	(382,671.17)
4705 Power Purchased	113,774,621.31		113,774,621.31	(34,343,745.95)	79,430,875.36
4707 Global adjustment purchased	-		-	34,343,745.95	34,343,745.95
4708 Charges -WMS	7,226,114.58		7,226,114.58	0.00	7,226,114.58
4714 Charges -NW	9,158,481.59		9,158,481.59	0.00	9,158,481.59
4716 Charges -CN	5,684,923.09		5,684,923.09	0.00	5,684,923.09
4750 Charges - LV	518,012.01		518,012.01	0.00	518,012.01
4751 Charges - SME	484,344.35		484,344.35	0.00	484,344.35
5005 Operation Supervision and Engineering	713,388.73		713,388.73	0.00	713,388.73
5010 Load Dispatching	51,765.11		51,765.11	0.00	51,765.11
5012 Station Buildings and fixtures expense	45,598.81		45,598.81	0.00	45,598.81
5014 Transformer Station Equipment - Operation Labour	20,497.00		20,497.00	0.00	20,497.00
5015 Transformer Station Equipment - Operation	161,483.65		161,483.65	0.00	161,483.65
5020 Overhead Distribution Lines and Feeders -Labour	197,594.29		197,594.29	0.00	197,594.29
5025 Overhead Distribution Lines and Feeders - Operation expenses	12,132.28		12,132.28	7,600.00	19,732.28
5040 Underground Distribution Lines and Feeders Labour	87,469.33		87,469.33	0.00	87,469.33
5045 Underground Distribution Lines and Feeders - expenses	291,703.56		291,703.56	0.00	291,703.56
5055 Underground Distribution Transformers - Operation	241.18		241.18	0.00	241.18
5065 Meter Expense	474,475.94		474,475.94	0.00	474,475.94
5070 Customer Premises - Operation Labour	126,427.32		126,427.32	0.00	126,427.32
5085 Miscellaneous Distribution Expenses	2,114,542.20		2,114,542.20	0.00	2,114,542.20
5105 Maintenance Supervision and Engineering	492,765.57		492,765.57	0.00	492,765.57
5114 Maintenance of Distribution Station Equipment	9,701.80		9,701.80	0.00	9,701.80
5120 Maintenance of Poles, Towers and Fixtures	98,453.45		98,453.45	0.00	98,453.45
5125 Maintenance of Overhead Conductors and Devices	769,627.26		769,627.26	0.00	769,627.26
5130 Maintenance of Overhead Services	156,681.03		156,681.03	0.00	156,681.03
5135 Overhead Distribution Lines and Feeders - Right of Way	244,299.92		244,299.92	0.00	244,299.92

	Original Filed CGAAP 2014 after removal of FMV)	Adjustment for FMV entry and Water and PILS	Original Filed CGAAP 2014	IFRS vs CGAAP 2014 adjustments	Restated IFRS 2014
5145 Maintenance of Underground Conduit	19,980.47		19,980.47	0.00	19,980.47
5150 Maintenance of Underground Conductors & Devices	242,172.93		242,172.93	0.00	242,172.93
5155 Maintenance of Underground Services	126,178.15		126,178.15	0.00	126,178.15
5160 Maintenance of Line Transformers	176,166.08		176,166.08	0.00	176,166.08
5175 Maintenance of Meters	86,888.07		86,888.07	(81,374.74)	5,513.33
5305 Supervision	1,411,000.30		1,411,000.30	968,556.94	2,379,557.24
5310 Meter Reading Expense	850,229.56		850,229.56	(476,493.29)	373,736.27
5315 Customer Billing	2,680,326.38	(78,884.99)	2,601,441.39	(130,292.81)	2,471,148.58
5320 Collecting	495,766.93		495,766.93	0.00	495,766.93
5325 Collecting - Cash Over and Short	41.34		41.34	0.00	41.34
5335 Bad Debt Expense	258,260.69		258,260.69	0.00	258,260.69
5340 Miscellaneous Customer Accounts Expense	242,276.00		242,276.00	0.00	242,276.00
5410 Community Relations - Sundry	79,138.47		79,138.47	0.00	79,138.47
5605 Executive Salaries and Expenses	383,246.74		383,246.74	0.00	383,246.74
5610 Management Salaries and Expenses	1,915,052.68	(21,766.25)	1,893,286.43	5,150.00	1,898,436.43
5615 General Administrative Salaries and Expenses	441,954.29		441,954.29	0.00	441,954.29
5620 Office Supplies and Expenses	81,567.70		81,567.70	0.00	81,567.70
5630 Outside Services Employed	40,800.00		40,800.00	0.00	40,800.00
5635 Property Insurance	312,398.70		312,398.70	0.00	312,398.70
5645 Employee Pensions and benefits	-		-	65,519.00	65,519.00
5655 Regulatory Expenses	233,003.01		233,003.01	0.00	233,003.01
5665 Miscellaneous General Expense	56,573.58		56,573.58	0.00	56,573.58
5675 Maintenance of General Plant	661,757.10		661,757.10	0.00	661,757.10
5705 Amortization Expense - Property Plant and Equipment	5,649,681.14	(6,036.00)	5,643,645.14	600,392.95	6,244,038.09
5715 Amortization of Intangibles and Other Electric	1,099,638.40	(1,099,638.40)	-	0.00	-
6005 Interest on Long Term Debt	979,088.93		979,088.93	0.00	979,088.93
6030 Interest on Debt to Associated Companies	1,362,190.68		1,362,190.68	0.00	1,362,190.68
6035 Other Interest Expense	251,148.70		251,148.70	0.00	251,148.70
6105 Taxes other that Income Taxes	259,958.35		259,958.35	0.00	259,958.35
6110 Income Taxes	572,867.30		572,867.30	0.00	572,867.30
6115 Provision for Future Income Taxes	(123,516.81)		(123,516.81)	(417,014.41)	(540,531.22)
6205 Donations	38,906.00		38,906.00	0.00	38,906.00
Net movement in regulatory balances, net of tax	-		-	0.00	-
Income Statement total	**(2,347,069.07)**	**(1,732,163.40)**	**(4,079,232.47)**	**27,500.66**	**(4,051,731.81)**

Trial Balance Summary					
Revenues	(166,147,156.29)	(525,837.76)	(166,672,994.05)	(514,542.98)	(167,187,537.03)
Expenses	163,800,087.22	(1,206,325.64)	162,593,761.58	542,043.64	163,135,805.22
(Profit)/Loss	(2,347,069.07)	(1,732,163.40)	(4,079,232.47)	27,500.66	(4,051,731.81)
Net Assets	273,346,749.81	0.00	273,346,749.81	10,103,747.16	283,450,496.97
Net Liabilities and Equity	(273,346,749.81)	0.00	(273,346,749.81)	(10,103,747.16)	(283,450,496.97)
IS (Profit)/Loss	(2,347,069.07)	(1,732,163.40)	(4,079,232.47)	27,500.66	(4,051,731.81)
Balance Sheet (profit)/Loss	(2,347,069.07)	(1,732,163.40)	(4,079,232.47)	27,500.66	(4,051,731.81)

Niagara Peninsula Energy Inc.
For the Twelve Months Ending December 31, 2014

RRR Part 1
Trial Balance Mapped to Financial Statement Grouping
2.1.13

		RRR = Financial Statements December 2014	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry and Water and PILS	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
1005	Cash	10,590,260.81				10,590,260.81		
1010	Cash Advance and Working Funds	2,074.63	10,592,335.44			2,074.63	10,592,335.44	
1100	Custom Accounts Receivable	10,937,580.39				10,937,580.39		
1104	Accounts Receivable - Recoverable Work	1,325,306.05				1,325,306.05		
1110	Other Accounts Receivable	644,069.07				644,069.07		
1130	Accumulated Provision for Uncollectible Accts	(496,230.89)	12,410,724.62			(496,230.89)	12,410,724.62	
1120	Accrued Utility Revenues	16,220,588.40	16,220,588.40			16,220,588.40	16,220,588.40	
1200	Accounts Receivable from Associated Companies	5,851.00	5,851.00			5,851.00	5,851.00	
2294	Accrual for Taxes,"Payments in Lieu"of Taxes	1,061,928.70	1,061,928.70			1,061,928.70	1,061,928.70	
1180	Prepayments	766,333.27				766,333.27		
1606	Organization	1,926.45	768,259.72			1,926.45	768,259.72	
1330	Plant Materials and Operating Supplies	1,481,013.21	1,481,013.21	42,540,701.09		1,481,013.21	1,481,013.21	42,540,701.09
1705	Land	82,347.02				82,347.02		
1708	Buildings and Fixtures	3,693,130.15				3,693,130.15		
1715	Station Equipment	2,742,786.83				2,742,786.83		
1735	Underground Conduit	1,090.59				1,090.59		
1740	Underground Conductors and Devices	138,793.40				138,793.40		
1805	Land	424,925.77				424,925.77		
1806	Land Rights	1,604,396.58				1,604,396.58		
1808	Buildings and Fixtures	111,638.13				111,638.13		
1815	Transformer Station Equipment - Normally Primary	75,622.38				75,622.38		
1820	Distribution Station Equipment - Normally Primary	6,867,625.70				6,867,625.70		
1830	Poles, Towers and Fixtures	45,208,940.44				45,208,940.44		
1835	Overhead Conductors and Devices	30,044,276.65				30,044,276.65		
1840	Underground Conduit	10,359,257.73				10,359,257.73		
1845	Underground Conductors and Devices	69,349,613.78				69,349,613.78		
1850	Line Transformers	38,491,416.02				38,491,416.02		
1855	Services	6,275,832.36				6,275,832.36		
1860	Meters	9,397,062.63				9,397,062.63		
1865	Other Installations on Customer's Premises	439.87				439.87		
1875	Street Lighting and Signal Systems	21,835.21				21,835.21		
1905	Land	508,969.83				508,969.83		
1908	Buildings and Fixtures	16,730,502.84				16,730,502.84		
1910	Leasehold Improvements	120,252.32				120,252.32		
1915	Office Furniture and Equipment	1,670,223.59				1,670,223.59		
1920	Computer Equipment-Hardware	4,057,105.13				4,057,105.13		
1925	Computer Software	3,229,308.26				3,229,308.26		
1930	Transportation Equipment	8,790,945.97				8,790,945.97		
1935	Stores Equipment	268,477.88				268,477.88		
1940	Tools, Shop and Garage Equipment	2,015,322.46				2,015,322.46		
1945	Measurement and Testing Equipment	204,006.18				204,006.18		
1955	Communication Equipment	1,075,265.93				1,075,265.93		
1960	Miscellaneous Equipment	72,951.31				72,951.31		
1980	System Supervisory Equipment	128,960.64				128,960.64		
1995	Contributions and Grants - Credit	(22,904,531.33)				(22,904,531.33)		
2005	Property Under Capital Leases	143,036.00				143,036.00		
2060	Electric Plant Acquisition Adjustment	142,276.60				142,276.60		
2065	Other Electric Plant Adjustment	45,509,515.44			(45,509,515.44)	0.00		
2105	Accumulated Amortization of Electric Utility-Plant	(120,788,373.59)				(120,788,373.59)		
2140	Accumulated Amortization of Electric Plant	(142,276.60)				(142,276.60)		

	RRR = Financial Statements December 2014	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry and Water and PILS	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
2160 Accumulated Amortization of Other Utility Plant	(31,811,975.56)	133,910,994.54	133,910,994.54	31,811,975.56	0.00	120,213,454.66	120,213,454.66
2296 Future Income Taxes - Current	1,204,168.40	1,204,168.40	1,204,168.40		1,204,168.40	1,204,168.40	1,204,168.40
2205 Accounts Payable	(19,711,631.87)				(19,711,631.87)		
2220 Miscellaneous Current and Accrued Liabilities	0.00				0.00		
2250 Debt Retirement Charges DRC payable	(759,130.32)				(759,130.32)		
2290 Commodity Taxes	1,466,742.24				1,466,742.24		
2292 Payroll Deductions/Expenses Payable	(1,469.06)				(1,469.06)		
2425 Other Deferred Credits	(520,752.92)	(19,526,241.93)			(520,752.92)	(19,526,241.93)	
2210 Current portion of Customer deposits	(728,569.49)	(728,569.49)			(728,569.49)	(728,569.49)	
2240 Accounts Payable to Associated Companies	(23,574.89)	(23,574.89)			(23,574.89)	(23,574.89)	
2260 Current Portion of Long Term Debt	(3,515,074.97)	(3,515,074.97)	(23,793,461.28)		(3,515,074.97)	(3,515,074.97)	(23,793,461.28)
2520 Other Long Term debt	0.00				0.00		
2525 Term Bank Loans-long term Portion	(33,724,569.68)				(33,724,569.68)		
2550 Advances from Associated Companies	(25,605,089.72)	(59,329,659.40)			(25,605,089.72)	(59,329,659.40)	
2320 Other Miscellaneous Non-current liabilities	(37,334.17)				(37,334.17)		
2335 Long Term Customer Deposits	(728,569.49)	(765,903.66)			(728,569.49)	(765,903.66)	
2310 Vested Sick Leave Liability	(50,135.10)	(50,135.10)			(50,135.10)	(50,135.10)	
2306 Employee Future Benefits	(3,907,283.00)	(3,907,283.00)			(3,907,283.00)	(3,907,283.00)	
1550 Hydro One Low Voltage Variance	174,128.27				174,128.27		
1551 Smart Metering Entity Variance	27,319.06				27,319.06		
1576 Accounting Changes Under CGAAP	(6,169,896.00)				(6,169,896.00)		
1580 RSVA - WMS	(1,300,556.42)				(1,300,556.42)		
1582 RSVA - One Time	0.00				0.00		
1584 RSVA - NW	992,790.88				992,790.88		
1586 RSVA - CN	727,844.84				727,844.84		
1588 RSVA - Power	(4,741,791.38)				(4,741,791.38)		
1588 RSVA - GA Non-RPP	4,425,150.65				4,425,150.65		
1518 RCVA - Retail	159,225.32				159,225.32		
1548 RCVA - STR	230,883.45				230,883.45		
1508 Other Regulatory Assets	27,767.71				27,767.71		
1562 Deferred Payments in Lieu of taxes	0.00				0.00		
1563 Deferred PILS contra Account	0.00				0.00		
1535 Smart Grid Deferral Account	18,720.96				18,720.96		
1555 Smart Meter Capital and Recovery Variance	1,295,154.75				1,295,154.75		
1556 Smart Meter OM&A Variance	(11,450.57)				(11,450.57)		
1521 Special Purpose Charge	0.00				0.00		
1595 Disposition and Recovery of Regulatory Balances	(1,224,135.95)	(5,368,844.43)	(69,421,825.59)		(1,224,135.95)	(5,368,844.43)	(69,421,825.59)
3005 Common Shares Issued	(31,245,882.02)	(31,245,882.02)			(31,245,882.02)	(31,245,882.02)	
3010 Contributed Surplus	(18,753,902.09)			18,753,902.09	0.00		
3047 Appropriations of Retained Earnings - current	(6,705,305.00)	(25,459,207.09)			(6,705,305.00)	(6,705,305.00)	
3040 Appropriated Retained Earnings	(26,588,418.98)			(3,956,723.81)	(29,912,617.79)		
3041 Appropriated Retained Earnings				632,525.00			
3046 Balance Transferred from Income	(2,347,069.07)			(1,732,163.40)	(4,079,232.47)		
3049 Dividends payable - Common Shares	1,200,000.00	(27,735,488.05)	(84,440,577.16)		1,200,000.00	(32,791,850.26)	(70,743,037.28)
Balance Sheet	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
4006 Residential Energy Sales	(39,971,818.36)				(39,971,818.36)		
4010 Commercial Energy Sales	(12,909,143.22)				(12,909,143.22)		

	RRR = Financial Statements December 2014	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry and Water and PILS	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
4025 Streetlighting energy sales	(658,175.31)				(658,175.31)		
4030 Sentinel Lighting Energy Sales	(19,412.15)				(19,412.15)		
4035 General Energy Sales	(60,216,072.27)	(113,774,621.31)			(60,216,072.27)	(113,774,621.31)	
4062 Billed WMS	(7,226,114.58)				(7,226,114.58)		
4066 Billed NW	(9,158,481.59)				(9,158,481.59)		
4068 Billed CN	(5,684,923.09)				(5,684,923.09)		
4075 Billed - LV	(518,012.01)				(518,012.01)		
4076 Billed SME Charge	(484,344.35)	(23,071,875.62)			(484,344.35)	(23,071,875.62)	
4080 Distribution Services Revenue	(30,261,924.91)	(30,261,924.91)		(632,525.00)	(30,894,449.91)	(30,894,449.91)	
4082 Retail Services Revenue	(41,658.40)				(41,658.40)		
4084 Service Transaction Requests (STR) Revenues	(970.50)	(42,628.90)			(970.50)	(42,628.90)	
4086 SSS Admin Charge	(144,761.88)	(144,761.88)	(167,295,812.62)		(144,761.88)	(144,761.88)	(167,928,337.62)
4705 Power Purchased	113,774,621.31				113,774,621.31		
4708 Charges -WMS	7,226,114.58				7,226,114.58		
4714 Charges -NW	9,158,481.59				9,158,481.59		
4716 Charges -CN	5,684,923.09				5,684,923.09		
4751 Charges -SME	518,012.01				518,012.01		
4750 Charges - LV	484,344.35	136,846,496.93	136,846,496.93		484,344.35	136,846,496.93	136,846,496.93
4215 Other Utility Operating Income	(60,586.30)				(60,586.30)		
4225 Late Payment Charges	(405,422.43)				(405,422.43)		
4355 Gain on Disposition of Utility and Other Property	(8,500.00)				(8,500.00)		
4360 Losses from disposition of Utility and Other Property	0.00				0.00		
4362 Loss on Retirement of Utility and Other Property	0.00				0.00		
4375 Revenues from Non-Utility Operations	(2,921,938.81)				(2,921,938.81)		
4235 Miscellaneous Service Revenues	(813,603.61)				(813,603.61)		
4380 Expenses from Non-Utility Operations	2,731,384.20			106,687.24	2,838,071.44		
4390 Miscellaneous Non-Operating Income	(105,335.82)				(105,335.82)		
4405 Interest and Dividend Income	(382,671.17)	(1,966,673.94)	(1,966,673.94)		(382,671.17)	(1,859,986.70)	(1,859,986.70)
5005 Operation Supervision and Engineering	713,388.73				713,388.73		
5010 Load Dispatching	51,765.11				51,765.11		
5012 Station Buildings and fixtures expense	45,598.81				45,598.81		
5014 Transformer Station Equipment - Operation Labour	20,497.00				20,497.00		
5015 Transformer Station Equipment - Operation	161,483.65				161,483.65		
5020 Overhead Distribution Lines and Feeders -Labour	197,594.29				197,594.29		
5025 Overhead Distribution Lines and Feeders - Operation ex	12,132.28				12,132.28		
5040 Underground Distribution Lines and Feeders Labour	87,469.33				87,469.33		
5045 Underground Distribution Lines and Feeders - expenses	291,703.56				291,703.56		
5055 Underground Distribution Transformer - Operations	241.18				241.18		
5065 Meter Expense	474,475.94				474,475.94		
5085 Miscellaneous Distribution Expenses	2,114,542.20				2,114,542.20		
5105 Maintenance Supervision and Engineering	492,765.57				492,765.57		
5112 Maintenance of Transformer Station Equipment	0.00				0.00		
5114 Maintenance of Distribution Station Equipment	9,701.80				9,701.80		
5120 Maintenance of Poles, Towers and Fixtures	98,453.45				98,453.45		
5125 Maintenance of Overhead Conductors and Devices	769,627.26				769,627.26		
5130 Maintenance of Overhead Services	156,681.03				156,681.03		
5135 Overhead Distribution Lines and Feeders - Right of Way	244,299.92				244,299.92		
5145 Maintenance of Underground Conduit	19,980.47				19,980.47		
5150 Maintenance of Underground Conductors & Devices	242,172.93				242,172.93		
5155 Maintenance of Underground Services	126,178.15				126,178.15		
5160 Maintenance of Line Transformers	176,166.08				176,166.08		
5175 Maintenance of Meters	86,888.07	6,593,806.81			86,888.07	6,593,806.81	6,593,806.81
5070 Customer Premises - Operation Labour	126,427.32				126,427.32		
5410 Community Relations - Sundry	79,138.47	205,565.79			79,138.47	205,565.79	205,565.79
5605 Executive Salaries and Expenses	383,246.74				383,246.74		

	RRR = Financial Statements December 2014	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry and Water and PILS	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
5610 Management Salaries and Expenses	1,915,052.68			(21,766.25)	1,893,286.43		
5615 General Administrative Salaries and Expenses	441,954.29				441,954.29		
5620 Office Supplies and Expenses	81,567.70				81,567.70		
5630 Outside Services Employed	40,800.00				40,800.00		
5635 Property Insurance	312,398.70				312,398.70		
5655 Regulatory Expenses	233,003.01				233,003.01		
5665 Miscellaneous General Expense	56,573.58				56,573.58		
5675 Maintenance of General Plant	661,757.10				661,757.10		
6005 Interest on Long Term Debt	979,088.93				979,088.93		
6030 Interest on Debt to Associated Companies	1,362,190.68				1,362,190.68		
6035 Other Interest Expense	251,148.70				251,148.70		
6105 Taxes other that Income Taxes	259,958.35				259,958.35		
6215 Penalties	0.00				0.00		
6205 Donations	38,906.00	7,017,646.46			38,906.00	6,995,880.21	6,995,880.21
5305 Supervision	1,411,000.30				1,411,000.30		
5310 Meter Reading Expense	850,229.56				850,229.56		
5315 Customer Billing	2,680,326.38			(78,884.99)	2,601,441.39		
5320 Collecting	495,766.93				495,766.93		
5325 Collecting - Cash Over and Short	41.34				41.34		
5335 Bad Debt Expense	258,260.69				258,260.69		
5340 Miscellaneous Customer Accounts Expense	242,276.00	5,937,901.20			242,276.00	5,859,016.21	5,859,016.21
5705 Amortization Expense - Property Plant and Equipment	5,649,681.14	5,649,681.14		(6,036.00)	5,643,645.14	5,643,645.14	5,643,645.14
5715 Amortization of Intangibles and Other Electric	1,099,638.40	1,099,638.40		(1,099,638.40)	0.00	0.00	0.00
			26,504,239.80		0.00		
4305 Regulatory Debits	3,115,330.27	3,115,330.27	3,115,330.27		3,115,330.27	3,115,330.27	3,115,330.27
6110 Income Taxes	572,867.30				572,867.30		
6115 Provision for Future Income Taxes	(123,516.81)	449,350.49	449,350.49		(123,516.81)	449,350.49	449,350.49
Income Statement total	**(2,347,069.07)**	**(2,347,069.07)**	**(2,347,069.07)**	**(1,732,163.40)**	**(4,079,232.47)**	**(4,079,232.47)**	**(4,079,232.47)**
Trial Balance Summary							
Revenues	(169,262,486.56)	(169,262,486.56)	(169,262,486.56)	(525,837.76)	(169,788,324.32)	(169,788,324.32)	(169,788,324.32)
Expenses	166,915,417.49	166,915,417.49	166,915,417.49	(1,206,325.64)	165,709,091.85	165,709,091.85	165,709,091.85
(Profit)/Loss	(2,347,069.07)	(2,347,069.07)	(2,347,069.07)	(1,732,163.40)	(4,079,232.47)	(4,079,232.47)	(4,079,232.47)
Net Assets	278,172,888.61	37,314,096.36	(25,676,956.10)	0.00	278,172,888.61	37,314,096.36	(25,676,956.10)
Net Liabilities and Equity	(278,172,888.61)	(37,314,096.36)	25,676,956.10	0.00	(278,172,888.61)	(37,314,096.36)	25,676,956.10
IS (Profit)/Loss	(2,347,069.07)	(2,347,069.07)	(2,347,069.07)	(1,732,163.40)	(4,079,232.47)	(4,079,232.47)	(4,079,232.47)
Balance Sheet (profit)/Loss	(2,347,069.07)	(2,347,069.07)	(2,347,069.07)	(1,732,163.40)	(4,079,232.47)	(4,079,232.47)	(4,079,232.47)

Niagara Peninsula Energy Inc.
For the Twelve Months Ending December 31, 2014
RRR Part 2
Trial Balance by Account
2.1.13

	RRR Financial Statement December 2014	**Adjustment for FMV entry and Water and PILS**	**Filed RRR restated for FMV removal**		
Current Assets					
1005 Cash	10,590,260.81		10,590,260.81	10,590,260.81	-
1010 Cash Advance and Working Funds	2,074.63		2,074.63	2,074.63	-
1100 Custom Accounts Receivable	10,937,580.39		10,937,580.39	10,937,580.39	-
1104 Accounts Receivable - Recoverable Work	1,325,306.05		1,325,306.05	1,325,306.05	-
1110 Other Accounts Receivable	644,069.07		644,069.07	644,069.07	-
1120 Accrued Utility Revenues	16,220,588.40		16,220,588.40	16,220,588.40	-
1130 Accumulated Provision for Uncollectible Accts	(496,230.89)		(496,230.89)	(496,230.89)	-
1180 Prepayments	766,333.27		766,333.27	766,333.27	-
1200 Accounts Receivable from Associated Companies	5,851.00		5,851.00	5,851.00	-
1330 Plant Materials and Operating Supplies	1,481,013.21		1,481,013.21	1,481,013.21	-
1495 Other Deferred assets	0.00			358,491.98	(358,491.98)
1508 Other Regulatory Assets	27,767.71		27,767.71	1,668,378.48	(1,640,610.77)
1518 RCVA - Retail	159,225.32		159,225.32	159,225.32	-
1521 Special Purpose Charge	0.00		0.00		-
1535 Smart Grid Deferral Account	18,720.96		18,720.96	18,720.96	-
1548 RCVA - STR	230,883.45		230,883.45	230,883.45	-
1550 Hydro One Low Voltage Variance	174,128.27		174,128.27	174,128.27	-
1551 Smart Metering Entity Variance	27,319.06		27,319.06	27,319.06	-
1555 Smart Meter Capital and Recovery Variance	1,295,154.75		1,295,154.75	1,295,154.75	-
1556 Smart Meter OM&A Variance	(11,450.57)		(11,450.57)	(11,450.57)	-
1562 Deferred Payments in Lieu of taxes	0.00		0.00		-
1563 Deferred PILS contra Account	0.00		0.00		-
1576 Accounting Changes Under CGAAP	(6,169,896.00)		(6,169,896.00)	(6,169,896.00)	-
1580 RSVA - WMS	(1,300,556.42)		(1,300,556.42)	(1,300,556.42)	-
1584 RSVA - NW	992,790.88		992,790.88	992,790.88	-
1586 RSVA - CN	727,844.84		727,844.84	727,844.84	-
1588 RSVA - Power	(4,741,791.38)		(4,741,791.38)	(4,741,791.38)	-
1589 RSVA - GA Non-RPP	4,425,150.65		4,425,150.65	4,425,150.65	-
1595 Disposition and Recovery of Regulatory Balances	(1,224,135.95)		(1,224,135.95)	(1,224,135.95)	-
1606 Organization	1,926.45		1,926.45	1,926.45	-
1705 Land	82,347.02		82,347.02	82,347.02	-
1708 Buildings and Fixtures	3,693,130.15		3,693,130.15	3,693,130.15	-
1715 Station Equipment	2,742,786.83		2,742,786.83	2,742,786.83	-
1735 Underground Conduit	1,090.59		1,090.59	1,090.59	-
1740 Underground Conductors and Devices	138,793.40		138,793.40	138,793.40	-
1805 Land	424,925.77		424,925.77	424,925.77	-
1806 Land Rights	1,604,396.58		1,604,396.58	1,604,396.58	-
1808 Buildings and Fixtures	111,638.13		111,638.13	111,638.13	-
1815 Transformer Station Equipment - Normally Primary	75,622.38		75,622.38	75,622.38	-
1820 Distribution Station Equipment - Normally Primary	6,867,625.70		6,867,625.70	6,867,625.70	-
1830 Poles, Towers and Fixtures	45,208,940.44		45,208,940.44	45,208,940.44	-
1835 Overhead Conductors and Devices	30,044,276.65		30,044,276.65	30,044,276.65	-
1840 Underground Conduit	10,359,257.73		10,359,257.73	10,359,257.73	-

		RRR Financial Statement December 2014	Adjustment for FMV entry and Water and PILS	Filed RRR restated for FMV removal		
1845	Underground Conductors and Devices	69,349,613.78		69,349,613.78	69,349,613.78	-
1850	Line Transformers	38,491,416.02		38,491,416.02	38,491,416.02	-
1855	Services	6,275,832.36		6,275,832.36	6,275,832.36	-
1860	Meters	9,397,062.63		9,397,062.63	9,397,062.63	-
1865	Other Installations on Customer's Premises	439.87		439.87	439.87	-
1875	Street Lighting and Signal Systems	21,835.21		21,835.21	21,835.21	-
1905	Land	508,969.83		508,969.83	508,969.83	-
1908	Buildings and Fixtures	16,730,502.84		16,730,502.84	16,730,502.84	-
1910	Leasehold Improvements	120,252.32		120,252.32	120,252.32	-
1915	Office Furniture and Equipment	1,670,223.59		1,670,223.59	1,670,223.59	-
1920	Computer Equipment-Hardware	4,057,105.13		4,057,105.13	4,057,105.13	-
1925	Computer Software	3,229,308.26		3,229,308.26	3,229,308.26	-
1930	Transportation Equipment	8,790,945.97		8,790,945.97	8,790,945.97	-
1935	Stores Equipment	268,477.88		268,477.88	268,477.88	-
1940	Tools, Shop and Garage Equipment	2,015,322.46		2,015,322.46	2,015,322.46	-
1945	Measurement and Testing Equipment	204,006.18		204,006.18	204,006.18	-
1955	Communication Equipment	1,075,265.93		1,075,265.93	1,075,265.93	-
1960	Miscellaneous Equipment	72,951.31		72,951.31	72,951.31	-
1980	System Supervisory Equipment	128,960.64		128,960.64	128,960.64	-
1995	Contributions and Grants - Credit	(22,904,531.33)		(22,904,531.33)	(16,054,387.58)	(6,850,143.75)
2005	Property Under Capital Leases	143,036.00		143,036.00	143,036.00	-
2060	Electric Plant Acquisition Adjustment	142,276.60		142,276.60	142,276.60	-
2065	Other Electric Plant Adjustment	45,509,515.44	(45,509,515.44)	0.00	45,509,515.44	-
2105	Accumulated Amortization of Electric Utility-Plant	(120,788,373.59)		(120,788,373.59)	(127,997,513.41)	7,209,139.82
2140	Accumulated Amortization of Electric Plant	(142,276.60)		(142,276.60)	(142,276.60)	-
2160	Accumulated Amortization of Other Utility Plant	(31,811,975.56)	31,811,975.56	0.00	(31,811,975.56)	-
2205	Accounts Payable	(19,711,631.87)		(19,711,631.87)	(19,731,631.87)	20,000.00
2210	Current portion of Customer deposits	(728,569.49)		(728,569.49)	(728,569.49)	-
2240	Accounts Payable to Associated Companies	(23,574.89)		(23,574.89)	(23,574.89)	-
2250	Debt Retirement Charges DRC payable	(759,130.32)		(759,130.32)	(759,130.32)	-
2260	Current Portion of Long Term Debt	(3,515,074.97)		(3,515,074.97)	(3,515,074.97)	-
2290	Commodity Taxes	1,466,742.24		1,466,742.24	1,466,742.24	-
2292	Payroll Deductions/Expenses Payable	(1,469.06)		(1,469.06)	(1,469.06)	-
2294	Accrual for Taxes,"Payments in Lieu"of Taxes	1,061,928.70		1,061,928.70	1,061,928.70	-
2296	Future Income Taxes - Current	1,204,168.40		1,204,168.40	-	1,204,168.40
2306	Employee Future Benefits	(3,907,283.00)		(3,907,283.00)	(3,907,283.00)	-
2310	Vested Sick Leave Liability	(50,135.10)		(50,135.10)	(50,135.10)	-
2320	Other Miscellaneous Non-current liabilities	(37,334.17)		(37,334.17)	(37,334.17)	-
2335	Long Term Customer Deposits	(728,569.49)		(728,569.49)	(728,569.49)	-
2425	Other Deferred Credits	(520,752.92)		(520,752.92)	(520,752.92)	-
2520	Other Long Term debt	0.00		0.00	-	-
2525	Term Bank Loans-long term Portion	(33,724,569.68)		(33,724,569.68)	(33,724,569.68)	-
2550	Advances from Associated Companies	(25,605,089.72)		(25,605,089.72)	(25,605,089.72)	-
3005	Common Shares Issued	(31,245,882.02)		(31,245,882.02)	(31,245,882.02)	-
3010	Contributed Surplus	(18,753,902.09)	18,753,902.09	0.00	(18,753,902.09)	-
3040	Appropriated Retained Earnings	(26,588,418.98)	(3,956,723.81)	(29,912,617.79)	(27,031,857.92)	443,438.94
3041	Appropriated Retained Earnings	0.00	632,525.00		-	-
3046	Balance Transferred from Income	(2,347,069.07)	(1,732,163.40)	(4,079,232.47)	(2,319,568.41)	(27,500.66)
3047	Appropriations of Retained Earnings - current	(6,705,305.00)		(6,705,305.00)	(6,705,305.00)	-
3049	Dividends payable - Common Shares	1,200,000.00		1,200,000.00	1,200,000.00	-
						-
Balance Sheet		0.00	0.00	0.00	0.00	-

	RRR Financial Statement December 2014	Adjustment for FMV entry and Water and PILS	Filed RRR restated for FMV removal		
4006 Residential Energy Sales	(39,971,818.36)		(39,971,818.36)	(39,971,818.36)	0.00
4010 Commercial Energy Sales	(12,909,143.22)		(12,909,143.22)	(12,909,143.22)	0.00
4025 Streetlighting energy sales	(658,175.31)		(658,175.31)	(658,175.31)	0.00
4030 Sentinel Lighting Energy Sales	(19,412.15)		(19,412.15)	(19,412.15)	0.00
4035 General Energy Sales	(60,216,072.27)		(60,216,072.27)	(60,216,072.27)	0.00
4062 Billed WMS	(7,226,114.58)		(7,226,114.58)	(7,226,114.58)	0.00
4066 Billed NW	(9,158,481.59)		(9,158,481.59)	(9,158,481.59)	0.00
4068 Billed CN	(5,684,923.09)		(5,684,923.09)	(5,684,923.09)	0.00
4075 Billed - LV	(518,012.01)		(518,012.01)	(518,012.01)	0.00
4076 Billed SME Charge	(484,344.35)		(484,344.35)	(484,344.35)	0.00
4080 Distribution Services Revenue	(30,261,924.91)	(632,525.00)	(30,894,449.91)	(27,960,285.20)	(2,301,639.71)
4082 Retail Services Revenue	(41,658.40)		(41,658.40)	(41,658.40)	0.00
4084 Service Transaction Requests (STR) Revenues	(970.50)		(970.50)	(970.50)	0.00
4086 SSS Admin Charge	(144,761.88)		(144,761.88)	(144,761.88)	0.00
4215 Other Utility Operating Income	(60,586.30)		(60,586.30)	(60,586.30)	0.00
4225 Late Payment Charges	(405,422.43)		(405,422.43)	(405,422.43)	0.00
4235 Miscellaneous Service Revenues	(813,603.61)		(813,603.61)	(1,328,146.59)	514,542.98
4305 Regulatory Debits	3,115,330.27		3,115,330.27	3,115,330.27	0.00
4355 Gain on Disposition of Utility and Other Property	(8,500.00)		(8,500.00)	(8,500.00)	0.00
4375 Revenues from Non-Utility Operations	(2,921,938.81)		(2,921,938.81)	(2,921,938.81)	0.00
4380 Expenses from Non-Utility Operations	2,731,384.20	106,687.24	2,838,071.44	2,731,384.20	0.00
4390 Miscellaneous Non-Operating Income	(105,335.82)		(105,335.82)	(105,335.82)	0.00
4405 Interest and Dividend Income	(382,671.17)		(382,671.17)	(382,671.17)	0.00
4705 Power Purchased	113,774,621.31		113,774,621.31	113,774,621.31	0.00
4708 Charges -WMS	7,226,114.58		7,226,114.58	7,226,114.58	0.00
4714 Charges -NW	9,158,481.59		9,158,481.59	9,158,481.59	0.00
4716 Charges -CN	5,684,923.09		5,684,923.09	5,684,923.09	0.00
4750 Charges - LV	518,012.01		518,012.01	518,012.01	0.00
4751 Charges - SME	484,344.35		484,344.35	484,344.35	0.00
5005 Operation Supervision and Engineering	713,388.73		713,388.73	713,388.73	0.00
5010 Load Dispatching	51,765.11		51,765.11	51,765.11	0.00
5012 Station Buildings and fixtures expense	45,598.81		45,598.81	45,598.81	0.00
5014 Transformer Station Equipment - Operation Labour	20,497.00		20,497.00	20,497.00	0.00
5015 Transformer Station Equipment - Operation	161,483.65		161,483.65	161,483.65	0.00
5020 Overhead Distribution Lines and Feeders -Labour	197,594.29		197,594.29	197,594.29	0.00
5025 Overhead Distribution Lines and Feeders - Operation expens	12,132.28		12,132.28	19,732.28	(7,600.00)
5040 Underground Distribution Lines and Feeders Labour	87,469.33		87,469.33	87,469.33	0.00
5045 Underground Distribution Lines and Feeders - expenses	291,703.56		291,703.56	291,703.56	0.00
5055 Underground Distribution Transformers - Operation	241.18		241.18	241.18	0.00
5065 Meter Expense	474,475.94		474,475.94	474,475.94	0.00
5070 Customer Premises - Operation Labour	126,427.32		126,427.32	126,427.32	0.00
5085 Miscellaneous Distribution Expenses	2,114,542.20		2,114,542.20	2,114,542.20	0.00
5105 Maintenance Supervision and Engineering	492,765.57		492,765.57	492,765.57	0.00
5114 Maintenance of Distribution Station Equipment	9,701.80		9,701.80	9,701.80	0.00
5120 Maintenance of Poles, Towers and Fixtures	98,453.45		98,453.45	98,453.45	0.00
5125 Maintenance of Overhead Conductors and Devices	769,627.26		769,627.26	769,627.26	0.00
5130 Maintenance of Overhead Services	156,681.03		156,681.03	156,681.03	0.00
5135 Overhead Distribution Lines and Feeders - Right of Way	244,299.92		244,299.92	244,299.92	0.00
5145 Maintenance of Underground Conduit	19,980.47		19,980.47	19,980.47	0.00

	RRR Financial Statement December 2014	Adjustment for FMV entry and Water and PILS	Filed RRR restated for FMV removal		
5150 Maintenance of Underground Conductors & Devices	242,172.93		242,172.93	242,172.93	0.00
5155 Maintenance of Underground Services	126,178.15		126,178.15	126,178.15	0.00
5160 Maintenance of Line Transformers	176,166.08		176,166.08	176,166.08	0.00
5175 Maintenance of Meters	86,888.07		86,888.07	5,513.33	81,374.74
5305 Supervision	1,411,000.30		1,411,000.30	815,503.33	595,496.97
5310 Meter Reading Expense	850,229.56		850,229.56	373,736.27	476,493.29
5315 Customer Billing	2,680,326.38	(78,884.99)	2,601,441.39	2,550,033.57	130,292.81
5320 Collecting	495,766.93		495,766.93	495,766.93	0.00
5325 Collecting - Cash Over and Short	41.34		41.34	41.34	0.00
5335 Bad Debt Expense	258,260.69		258,260.69	258,260.69	0.00
5340 Miscellaneous Customer Accounts Expense	242,276.00		242,276.00	242,276.00	0.00
5410 Community Relations - Sundry	79,138.47		79,138.47	79,138.47	0.00
5605 Executive Salaries and Expenses	383,246.74		383,246.74	383,246.74	0.00
5610 Management Salaries and Expenses	1,915,052.68	(21,766.25)	1,893,286.43	1,920,202.68	(5,150.00)
5615 General Administrative Salaries and Expenses	441,954.29		441,954.29	441,954.29	0.00
5620 Office Supplies and Expenses	81,567.70		81,567.70	81,567.70	0.00
5630 Outside Services Employed	40,800.00		40,800.00	40,800.00	0.00
5635 Property Insurance	312,398.70		312,398.70	312,398.70	0.00
5655 Regulatory Expenses	233,003.01		233,003.01	233,003.01	0.00
5665 Miscellaneous General Expense	56,573.58		56,573.58	56,573.58	0.00
5675 Maintenance of General Plant	661,757.10		661,757.10	661,757.10	0.00
5705 Amortization Expense - Property Plant and Equipment	5,649,681.14	(6,036.00)	5,643,645.14	6,250,074.09	(600,392.95)
5715 Amortization of Intangibles and Other Electric	1,099,638.40	(1,099,638.40)	0.00	1,099,638.40	0.00
6005 Interest on Long Term Debt	979,088.93		979,088.93	979,088.93	0.00
6030 Interest on Debt to Associated Companies	1,362,190.68		1,362,190.68	1,362,190.68	0.00
6035 Other Interest Expense	251,148.70		251,148.70	251,148.70	0.00
6105 Taxes other that Income Taxes	259,958.35		259,958.35	259,958.35	0.00
6110 Income Taxes	572,867.30		572,867.30	572,867.30	0.00
6115 Provision for Future Income Taxes	(123,516.81)		(123,516.81)	(540,531.22)	417,014.41
6205 Donations	38,906.00		38,906.00	38,906.00	0.00
					0.00
Income Statement total	**(2,347,069.07)**	**(1,732,163.40)**	**(4,079,232.47)**	**(1,647,501.61)**	(699,567.46)

Trial Balance Summary				
Revenues	(166,147,156.29)	(525,837.76)	(166,672,994.05)	(164,360,059.56)
Expenses	163,800,087.22	(1,206,325.64)	162,593,761.58	162,712,557.95
(Profit)/Loss	(2,347,069.07)	(1,732,163.40)	(4,079,232.47)	(1,647,501.61)
Net Assets	278,172,888.61	0.00	278,172,888.61	285,817,966.71
Net Liabilities and Equity	(278,172,888.61)	0.00	(278,172,888.61)	(285,817,966.71)
IS (Profit)/Loss	(2,347,069.07)	(1,732,163.40)	(4,079,232.47)	(1,647,501.61)
Balance Sheet (profit)/Loss	(2,347,069.07)	(1,732,163.40)	(4,079,232.47)	(2,319,568.41)

Niagara Peninsula Energy Inc.
FMV Bump
2.1.13

Balance Sheet

		2007 FMV entry	Entry hits Retained Earnings	2007 FMV entry summary	2008	2009	2010	2011	2012	2013	2013	2014 Net Adjustment on RRR to RE
1	PWU AR PWPower	(216,069.30)	216,069.30									
1	Due from PW power	1,400,000.00	(1,400,000.00)									
1	Future PILS	(5,168,552.00)	5,168,552.00									
1	Inventory	7,684.34	(7,684.34)									
	Fixed assets Total FMV Bump	45,735,559.44		45,735,559.44	45,735,559.44	45,735,559.44	45,735,559.44					
	Adjustment for PW software				-	-	(226,044.00)					
							45,509,515.44	45,509,515.44	45,509,515.44	45,509,515.44	45,509,515.44	
	Accum Deprec Total FMV Bump	(24,083,153.39)		(24,083,153.39)	(24,083,153.39)	(25,239,221.08)	(26,348,210.08)	(27,355,968)	(28,442,637)	(29,580,061)	(30,712,338)	
	Adjustment for PW software						226,044					
	Current year depreciation				(1,156,068)	(1,108,989)	(1,233,802)	(1,086,669)	(1,137,424)	(1,132,277)	(1,099,638)	
					(25,239,221)	(26,348,210)	(27,355,968)	(28,442,637)	(29,580,061)	(30,712,338)	(31,811,977)	
	Contributed Surplus	(18,753,902.09)		(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	
1	Retained Earnings	1,078,433.00	(1,078,433.00)	-								
sum of 1's	Retained Earnings net adjustment		(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	
	Cummulative impact on RE for Depreciation FMV bump				1,156,068	2,265,057	3,498,859	3,498,859	4,585,528	5,722,952	6,855,229	3,956,724.83
	Depreciation expense to be closed to Cummulative impact on RE							1,086,669	1,137,424	1,132,277	1,099,638	
	Net	(0.00)	-	-	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	-	-	

Income Statement

	2008	2009	2010	2011	2012	2013	2013
Depreciation expense FMV bump	1,156,068	1,111,638	1,233,802	1,086,669	1,137,424	1,132,277	1,099,638
Adjust depreciation expense FMV bump	0	-2649	0	0	0		
	1,156,068	1,108,989	1,233,802	1,086,669	1,137,424	1,132,277	1,099,638

Appendix 1-33

OEB 2020 Benchmarking-Spreadsheet-Forecast-Model

Summary of Cost Benchmarking Results

Niagara Peninsula Energy Inc.

Cost Benchmarking Summary	2018 (History)	2019 (Bridge)	2020 (Test Year)	2021	2022	2023
Actual Total Cost	41,988,255	43,962,086	45,370,241	46,912,950	48,162,429	49,122,126
Predicted Total Cost	41,457,453	43,133,170	44,949,463	46,840,052	48,562,137	50,347,768
Difference	530,802	828,916	420,778	72,898	(399,708)	(1,225,642)
Percentage Difference (Cost Performance)	**1.3%**	**1.9%**	**0.9%**	**0.16%**	**-0.83%**	**-2.46%**
Three-Year Average Performance			1.4%	1.00%	0.09%	-1.05%
Stretch Factor Cohort						
Annual Result	3	3	3	3	3	3
Three Year Average			3	3	3	3

Data Required for Cost Benchmarking

Niagara Peninsula Energy Inc.

Select LDC from Dropdown Box: Niagara Peninsula Energy Inc.

Required Item		History 2018	History 2019	Bridge 2020	Test Year 2021	Additonal Years for Custom IR Filings 2022	2023	2024	
	Gross Capital Cost Additions Data								
1	Total Gross Capital Additions	14,985,908	16,169,649	17,282,345	17,377,598	17,377,598	17,377,598	17,377,598	Enter Values
2	HV Gross Capital Additions	-	199,245	75,000	1,699,597				Enter Values
	Output and Other Business Conditions								
3	Number of Customers	55,593	56,067	56,673	57,286	57,286	57,286	57,286	Enter Values
4	Delivery Volume	1,217,476,816	1,210,020,079	1,210,020,079	1,210,020,079	1,210,020,079	1,210,020,079	1,210,020,079	Enter Values
5	Annual Peak Demand	254,506	256,280	256,280	256,280	256,280	256,280	256,280	Enter Values
6	Distribution Circuit-km	2,024	2,041	2,041	2,041	2,041	2,041	2,041	Enter Values
7	Ten Year Customer Growth Percentage	10.62%	10.6%	10.6%	10.6%	10.6%	10.6%	10.6%	Enter Values
	Inflation Measures								
8	Wage Growth	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	Enter values. The default values provided reflect recent historical growth.
9	Growth in Economy-wide Inflation	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	provided reflect recent historical
10	Rate of Return (WACC)	6.02%	6.02%	6.02%	6.02%	6.02%	6.02%	6.02%	Enter Values
	OM&A Expenses Included in Cost Benchmarking								
Choose a Method:	N **Use Method 1 [1A - 1B + 1C]**	(74,346)	-	-	-	-	-	-	Formula
	Y **Use Method 2 [2A - 2B + 2C]**	17,326,922	18,373,647	18,752,903	19,458,920	19,718,507	19,718,507	19,718,507	Formula
11	**OM&A Values Transfered to Calculations Worksheet**	17,326,922	18,373,647	18,752,903	19,458,920	19,718,507	19,718,507	19,718,507	Formula

Method 1: Enter Values Calculated Elsewhere — Enter Values Supported by Separate Calculations

		2018	2019	2020	2021	2022	2023	2024	
1A	Total OM&A Consistent with accounts included in [2B]								Enter Values
1B	HV Cost (Accounts 5014, 5015, and 5112) if included in total	168,428							Enter Values
1C	LV Adjustment	94,082							Enter Values

Method 2: Enter Detailed Data

OM&A Data

		2018	2019	2020	2021	2022	2023	2024	
5005	Operation Supervision and Engineering	883,892	990,133	857,236	829,932				Enter Values
5010	Load Dispatching	13,287	9,124	10,649	10,862				Enter Values
5012	Station Buildings and Fixtures	99,329	147,870	129,597	128,784				Enter Values
5014	Transformer Station Equipment - Operation Labor	12,173	45,104	36,033	35,168				Enter Values
5015	Transformer Station Equipment - Operation Supplies and Expenses	156,255	163,498	254,739	298,352				Enter Values
5016	Distribution Station Equipment - Operation Labor	-							Enter Values
5017	Distribution Station Equipment - Operation Supplies and Expenses	-							Enter Values
5020	Overhead Distribution Lines and Feeders - Operation Labor	337,500	293,751	269,957	267,993				Enter Values
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	84,197	107,226	97,722	96,791				Enter Values
5035	Overhead Distribution Transformers - Operation	-							Enter Values
5040	Underground Distribution Lines and Feeders - Operation Labor	119,802	199,190	162,231	180,728				Enter Values
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	360,804	379,343	379,691	382,485				Enter Values
5055	Overhead Distribution Lines and Feeders	-	-	-	-				Enter Values
5065	Meter Expense	487,591	397,351	478,659	392,809				Enter Values
5070	Customer Premises - Operation Labor	156,014	131,732	113,307	110,987				Enter Values
5075	Customer Premises - Operation Materials and Supplies	-							Enter Values

5085	Miscellaneous Distribution Expense	1,747,444	2,121,356	2,058,903	2,063,839				Enter Values
5090	Underground Distribution Lines and Feeders - Rental Paid	-							Enter Values
5095	Overhead Distribution Lines and Feeders - Rental Paid	-							Enter Values
5096	Other Rent (Distribution)	-							Enter Values
	Subtotal: Operation	**4,458,287**	**4,985,677**	**4,848,724**	**4,798,729**	-	-	-	Formula
5105	Maintenance Supervision and Engineering	472,897	457,769	472,481	440,517				Enter Values
5110	Maintenance of Buildings and Fixtures	-							Enter Values
5112	Maintenance of Transformer Station Equipment	-	3,950	-	-				Enter Values
5114	Maintenance of Distribution Station Equipement	41,546	22,933	35,726	40,194				Enter Values
5120	Maintenance of Poles, Towers and Fixtures	121,040	117,003	113,961	115,189				Enter Values
5125	Maintenance of Overhead Conductors and Devices	806,530	914,429	833,917	824,045				Enter Values
5130	Maintenance of Overhead Services	241,563	271,956	231,494	227,911				Enter Values
5135	Overhead Distribution Lines and Feeders - Right of Way	346,945	371,116	371,437	376,362				Enter Values
5145	Maintenance of Underground Conduit	18,987	39,289	31,236	31,231				Enter Values
5150	Maintenance of Underground Conductors and Devices	257,378	220,253	233,734	243,981				Enter Values
5155	Maintenance of Underground Services	194,159	177,101	162,441	161,059				Enter Values
5160	Maintenance of Line Transformers	88,066	82,773	80,847	117,344				Enter Values
5175	Maintenance of Meters	-							Enter Values
	Subtotal: Maintenance	**2,589,112**	**2,678,573**	**2,567,275**	**2,577,832**	-	-	-	Formula
5305	Supervision (Billing and Collection)	1,249,336	1,209,734	1,373,308	1,560,431				Enter Values
5310	Meter Reading Expense	502,044	586,734	597,263	869,479				Enter Values
5315	Customer Billing	2,928,066	3,147,231	3,354,142	3,398,666				Enter Values
5320	Collecting	502,452	441,420	507,173	510,424				Enter Values
5325	Collecting - Cash Over and Short	87	(183)	-	-				Enter Values
5330	Collection Charges	-							Enter Values
5340	Miscellaneous Customer Account Expenses	226,768	237,356	223,471	96,581				Enter Values
	Subtotal : Billing and Collections	**5,408,753**	**5,622,294**	**6,055,356**	**6,435,581**	-	-	-	Formula
5405	Supervision (Community Relations)	-							Enter Values
5410	Community Relations - Sundry	132,561	133,276	129,200	102,200				Enter Values
5420	Community Safety Program	-							Enter Values
5425	Miscellaneous Customer Service and Informational Expense	-							Enter Values
	Subtotal: Community Relations	**132,561**	**133,276**	**129,200**	**102,200**	-	-	-	Formula
5605	Executive Salaries and Expenses	449,088	526,833	538,749	543,394				Enter Values
5610	Management Salaries and Expenses	2,248,167	2,543,051	2,856,922	3,035,613				Enter Values
5615	General Administrative Salaries and Expenses	533,578	523,112	511,143	618,070				Enter Values
5620	Office Supplies	77,218	84,414	84,830	87,545				Enter Values
5625	Administrative Expense Transferred - Credit	-							Enter Values
5630	Outside Services Employed	50,004	53,000	54,530	55,601				Enter Values
5640	Injuries and Damages	-							Enter Values
5645	OMERS Pensions and Benefits	-							Enter Values
5646	Employee Pensions and OPEB	-							Enter Values
5647	Employee Sick Leave	-							Enter Values
5650	Franchise Requirements	-							Enter Values
5655	Regulatory Expenses	281,798	267,824	273,831	385,490				Enter Values
5665	Miscellaneous General Expenses	80,603	79,373	78,531	81,741				Enter Values
5670	Rent (Administrative and General)	-							Enter Values
5672	Lease Payment Expense	-							Enter Values
5675	Maintenance of General Plant	766,513	710,523	659,793	668,132				Enter Values
5680	Electrical Safety Authority Fees	-							Enter Values
	Sutotal: A&G Expenses	**4,486,970**	**4,788,130**	**5,058,329**	**5,475,586**	-	-	-	Formula
5635	Property Insurance	325,584	304,315	310,858	328,579				Enter Values
6210	Life Insurance	-							Enter Values
	Subtotal: Insurance	**325,584**	**304,315**	**310,858**	**328,579**	-	-	-	Formula
5515	Advertinsing	-							Enter Values
	Subtotal Advertising	-	-	-	-	-	-	-	Formula
2A	**Total of Above Accounts Used for Benchmarking**	17,401,268	**18,512,265**	**18,969,742**	**19,718,507**	**19,718,507**	**19,718,507**	**19,718,507**	Formula
Adjustments to OM&A for Benchmarking									
	5014	12,173	45,104	36,033	35,168	-	-	-	Formula
	5015	156,255	163,498	254,739	298,352	-	-	-	Formula
	5112	-	3,950	-	-	-	-	-	Formula
2B	**Subtotal: HV Adjustment (to subtract from cost)**	**168,428**	**212,551**	**290,772**	**333,520**	-	-	-	**Formula**
2C	**LV Adjustment**	**94,082**	73,933	73,933	73,933				**Enter Values**

Benchmarking Calculations for LDC Forecasting

Selected LDC: Niagara Peninsula Energy Inc.

Line Reference Number		Row Nu	Account	2018	Forecasted Values 2019	2020	2021	2022	2023	2024
			Section 1: Source Data and OM&A Calculations							
1	**OM&A Data (Detail may be hidden or expanded using the +/- buttons to the left of the row numbers)**									
2	5005	2	Operation Supervision and Engineering	883,892						
3	5010	3	Load Dispatching	13,287						
4	5012	4	Station Buildings and Fixtures	99,329						
5	5014	5	Transformer Station Equipment - Operation Labor	12,173						
6	5015	6	Transformer Station Equipment - Operation Supplies and Expenses	156,255						
7	5016	7	Distribution Station Equipment - Operation Labor	-						
8	5017	8	Distribution Station Equipment - Operation Supplies and Expenses	-						
9	5020	9	Overhead Distribution Lines and Feeders - Operation Labor	337,500						
10	5025	10	Overhead Distribution Lines and Feeders - Operation Supplies and E	84,197						
11	5035	11	Overhead Distribution Transformers - Operation	-						
12	5040	12	Underground Distribution Lines and Feeders - Operation Labor	119,802						
13	5045	13	Underground Distribution Lines and Feeders - Operation Supplies an	360,804						
14	5055	14	Overhead Distribution Lines and Feeders	-						
15	5065	15	Meter Expense	487,591						
16	5070	16	Customer Premises - Operation Labor	156,014						
17	5075	17	Customer Premises - Operation Materials and Supplies	-						
18	5085	18	Miscellaneous Distribution Expense	1,747,444						
19	5090	19	Underground Distribution Lines and Feeders - Rental Paid	-						
20	5095	20	Overhead Distribution Lines and Feeders - Rental Paid	-						
21	5096	21	Other Rent (Distribution)	-						
22			**Subtotal: Operation**	4,458,287						
23	5105	22	Maintenance Supervision and Engineering	472,897						
24	5110	23	Maintenance of Buildings and Fixtures	-						
25	5112	24	Maintenance of Transformer Station Equipment	-						
26	5114	25	Maintenance of Distribution Station Equipement	41,546						
27	5120	26	Maintenance of Poles, Towers and Fixtures	121,040						
28	5125	27	Maintenance of Overhead Conductors and Devices	806,530						
29	5130	28	Maintenance of Overhead Services	241,563						
30	5135	29	Overhead Distribution Lines and Feeders - Right of Way	346,945						
31	5145	30	Maintenance of Underground Conduit	18,987						
32	5150	31	Maintenance of Underground Conductors and Devices	257,378						
33	5155	32	Maintenance of Underground Services	194,159						
34	5160	33	Maintenance of Line Transformers	88,066						
35	5175	34	Maintenance of Meters	-						
36			**Subtotal: Maintenance**	2,589,112						
37	5305	35	Supervision (Billing and Collection)	1,249,336						
38	5310	36	Meter Reading Expense	502,044						
39	5315	37	Customer Billing	2,928,066						
40	5320	38	Collecting	502,452						
41	5325	39	Collecting - Cash Over and Short	87						
42	5330	40	Collection Charges	-						
43	5340	41	Miscellaneous Customer Account Expenses	226,768						
44			**Subtotal : Billing and Collections**	5,408,753						
45	5405	42	Supervision (Community Relations)	-						
46	5410	43	Community Relations - Sundry	132,561						
47	5420	44	Community Safety Program	-						
48	5425	45	Miscellaneous Customer Service and Informational Expenses	-						
49			**Subtotal: Community Relations**	132,561						

Line Reference Number		Row Nu	Account	2018	2019	2020	2021	2022	2023	2024
50	5605	47	Executive Salaries and Expenses	449,088						
51	5610	48	Management Salaries and Expenses	2,248,167						
52	5615	49	General Administrative Salaries and Expenses	533,578						
53	5620	50	Office Supplies	77,218						
54	5625	51	Administrative Expense Transferred - Credit	-						
55	5630	52	Outside Services Employed	50,004						
56	5640	53	Injuries and Damages	-						
57	5645	54	OMERS Pensions and Benefits	-						
58	5646	55	Employee Pensions and OPEB	-						
59	5647	56	Employee Sick Leave	-						
60	5650	57	Franchise Requirements	-						
61	5655	58	Regulatory Expenses	281,798						
62	5665	59	Miscellaneous General Expenses	80,603						
63	5670	60	Rent (Administrative and General)	-						
64	5672	61	Lease Payment Expense	-						
65	5675	62	Maintenance of General Plant	766,513						
66	5680	63	Electrical Safety Authority Fees	-						
67			**Sutotal: A&G Expenses**	4,486,970						
68	5635	64	Property Insurance	325,584						
69	6210	65	Life Insurance	-						
70			**Subtotal: Insurance**	325,584						
71	5515	46	Advertinsing	-						
72			**Subtotal Advertising**	-						
73			**Total of Above Accounts Used for Benchmarking**	17,401,268						
74										
75	**Adjustments to OM&A for Benchmarking**									
76			5014	12,173						
77			5015	156,255						
78			5112	-						
79			Subtotal: HV Adjustment (to subtract from cost)	168,428						
80			LV Adjustment	94,082						
81			Total Adjusted OM&A Expense	17,326,922	18,373,647	18,752,903	19,458,920	19,718,507	19,718,507	19,718,507
82										
83	**Gross Capital Cost Additions Data**									
84			Total Gross Capital Additions	14,985,908	16,169,649	17,282,345	17,377,598	17,377,598	17,377,598	17,377,598
85			HV Gross Capital Additions	-	199,245	75,000	1,699,597	-	-	-
86										
87	**Output and Other Business Conditions**									
88			Number of Customers	55,593	56,067	56,673	57,286	57,286	57,286	57,286
89			Delivery Volume	1,217,476,816	1,210,020,079	1,210,020,079	1,210,020,079	1,210,020,079	1,210,020,079	1,210,020,079
90			Annual Peak Demand	254,506	256,280	256,280	256,280	256,280	256,280	256,280
91			Distribution Circuit km	2,024	2,041	2,041	2,041	2,041	2,041	2,041
92										
93										

Section 2: Actual Cost Calculations

				2018	2019	2020	2021	2022	2023	2024
94	**Actual Cost**									
95										
96	OM&A			17,326,921.76	18,373,646.59	18,752,903.14	19,458,919.64	19,718,506.65	19,718,506.65	
97										
98	Capital									
99			Rate of Return	6.02%	6.02%	6.02%	6.02%	6.02%	6.02%	6.02%
100			Depreciation Rate	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%
101			Construction Cost Index	170.06	172.80	175.59	178.43	181.30	184.23	187.20
102			Capital Price	17.88	18.17	18.46	18.76	19.07	19.37	19.69
103			Gross Plant Additions	14,985,908	16,169,649	17,282,345	17,377,598	17,377,598	17,377,598	17,377,598
104			HV Capital Additions	-	199,245	75,000	1,699,597	-	-	-
105			Quantity of Capital Additions	88,121	92,419	97,996	87,868	95,847	94,325	92,827
106			Quantity of Capital Removed	62,104	63,299	64,635	66,167	67,163	68,479	69,666
107			Capital Quantity	1,379,055	1,408,176	1,441,537	1,463,239	1,491,923	1,517,769	1,540,931
108			Capital Cost	24,661,333	25,588,440	26,617,338	27,454,030	28,443,923	29,403,619	30,334,041
109										
110	Total Actual Cost			41,988,255	43,962,086	45,370,241	46,912,950	48,162,429	49,122,126	30,334,041

Section 3: Predicted Cost Calculations

111 **Predicted Cost**

112

113 **Output Quantity**

Line Reference Number	Row Nu	Account	2018	2019	2020	2021	2022	2023	2024
114		Number of Customers	55,593	56,067	56,673	57,286	57,286	57,286	57,286
115		Delivery Volume	1,217,476,816	1,210,020,079	1,210,020,079	1,210,020,079	1,210,020,079	1,210,020,079	1,210,020,079
116		Annual Peak Demand	254,506	256,280	256,280	256,280	256,280	256,280	256,280
117		Capacity Proxy	269,269	269,269	269,269	269,269	269,269	269,269	269,269
118									
119		**Input Prices**							
120		GDP IPI [30% Weight]	120.3	122.3	124.3	126.3	128.3	130.4	132.5
121		Average Hourly Earnings [70% Weight]	1,021.53	1,051.36	1,082.07	1,113.66	1,146.18	1,179.65	1,214.10
122		OM&A Price Index Growth [30% GDPIPI growth + 70% AWE Growth	2.495%	2.495%	2.495%	2.495%	2.495%	2.495%	2.495%
123		OM&A Price Index Level	125.29	128.46	131.70	135.03	138.44	141.94	145.52
124									
125		Capital Price Index	17.88	18.17	18.46	18.76	19.07	19.37	19.69
126									
127		**Business Conditions**							
128		Line km	2,024.00	2,041.00	2,041.00	2,041.00	2,041.00	2,041.00	2,041.00
129		2002-2013 Average Line km	2,025.35	2,026.40	2,027.31	2,028.11	2,028.83	2,029.51	2,030.14
130		Customers Ten Years Ago	50,255						
131		Ten Year Customer Growth Percentage	10.62%	10.62%	10.62%	10.62%	10.62%	10.62%	10.62%
132									
133	(Details of the predicted cost calculations may be hidden by using the +/- button to the left of row 248)								
134									
135	**Company Values for Variables Used in the Prediction Equation**								
136									
137		Constant	1.00	1.00	1.00	1.00	1.00	1.00	1.00
138		Capital Price / OM&A Price (WK)	0.1427	0.1415	0.1402	0.1390	0.1377	0.1365	0.1353
139		Customers (Y1)	55,593	56,067	56,673	57,286	57,286	57,286	57,286
140		Capacity (Y2)	269,269	269,269	269,269	269,269	269,269	269,269	269,269
141		Deliveries (Y3)	1,217,476,816	1,210,020,079	1,210,020,079	1,210,020,079	1,210,020,079	1,210,020,079	1,210,020,079
142		Average Line Length	2,025.4	2,026.4	2,027.3	2,028.1	2,028.8	2,029.5	2,030.1
143		Customers Added in last 10 years	10.62%	10.62%	10.62%	10.62%	10.62%	10.62%	10.62%
144		Trend	12	13	14	15	16	17	18
145									
146									
147	**Company-Specific Parameter Estimates***								
148	91	Constant	12.7877	12.7877	12.7877	12.7877	12.7877	12.7877	12.7877
149	92	Capital Price / OM&A Price (WK)	0.6288	0.6288	0.6288	0.6288	0.6288	0.6288	0.6288
150	93	Customers (Y1)	0.4907	0.4907	0.4907	0.4907	0.4907	0.4907	0.4907
151	94	Capacity (Y2)	0.1379	0.1379	0.1379	0.1379	0.1379	0.1379	0.1379
152	95	Deliveries (Y3)	0.1032	0.1032	0.1032	0.1032	0.1032	0.1032	0.1032
153	96	WKWK	0.1228	0.1228	0.1228	0.1228	0.1228	0.1228	0.1228
154	97	Y1Y1	(0.3044)	(0.3044)	(0.3044)	(0.3044)	(0.3044)	(0.3044)	(0.3044)
155	98	Y2Y2	0.2329	0.2329	0.2329	0.2329	0.2329	0.2329	0.2329
156	99	Y3Y3	0.1621	0.1621	0.1621	0.1621	0.1621	0.1621	0.1621
157	100	WKY1	0.0544	0.0544	0.0544	0.0544	0.0544	0.0544	0.0544
158	101	WKY2	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092
159	102	WKY3	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003
160	103	Y1Y2	0.0838	0.0838	0.0838	0.0838	0.0838	0.0838	0.0838
161	104	Y1Y3	0.0686	0.0686	0.0686	0.0686	0.0686	0.0686	0.0686
162	105	Y2Y3	(0.1971)	(0.1971)	(0.1971)	(0.1971)	(0.1971)	(0.1971)	(0.1971)
163	106	Average Line Length	0.2649	0.2649	0.2649	0.2649	0.2649	0.2649	0.2649
164	107	Customers Added in last 10 years	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193
165	108	Trend	0.0164	0.0164	0.0164	0.0164	0.0164	0.0164	0.0164
166									
167	**Sample Mean Values**								
168									
169		Constant	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
170		Capital Price / OM&A Price (WK)	0.1644	0.1644	0.1644	0.1644	0.1644	0.1644	0.1644
171		Customers (Y1)	63,422.3118	63,422.3118	63,422.3118	63,422.3118	63,422.3118	63,422.3118	63,422.3118
172		Capacity (Y2)	345,129.0146	345,129.0146	345,129.0146	345,129.0146	345,129.0146	345,129.0146	345,129.0146
173		Deliveries (Y3	1,630,327,994	1,630,327,994	1,630,327,994	1,630,327,994	1,630,327,994	1,630,327,994	1,630,327,994
174		WKWK	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
175		Y1Y1	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
176		Y2Y2	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
177		Y3Y3	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
178		WKY1	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
179		WKY2	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
180		WKY3	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
181		Y1Y2	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
182		Y1Y3	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
183		Y2Y3	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
184		Average Line Length	2,723	2,723	2,723	2,723	2,723	2,723	2,723

Line Reference Number	Row Nu	Account	2018	2019	2020	2021	2022	2023	2024
185		Customers Added in last 10 years	0.1286	0.1286	0.1286	0.1286	0.1286	0.1286	0.1286
186									
187									
188									
189	**2013 Values Logged and Mean Scaled (where applicable)**								
190									
191		Constant	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
192		Capital Price / OM&A Price (WK)	(0.1414)	(0.1503)	(0.1592)	(0.1682)	(0.1771)	(0.1861)	(0.1950)
193		Customers (Y1)	(0.1318)	(0.1233)	(0.1125)	(0.1018)	(0.1018)	(0.1018)	(0.1018)
194		Capacity (Y2)	(0.2482)	(0.2482)	(0.2482)	(0.2482)	(0.2482)	(0.2482)	(0.2482)
195		Deliveries (Y3)	(0.2920)	(0.2981)	(0.2981)	(0.2981)	(0.2981)	(0.2981)	(0.2981)
196		WKWK	0.0100	0.0113	0.0127	0.0141	0.0157	0.0173	0.0190
197		Y1Y1	0.0087	0.0076	0.0063	0.0052	0.0052	0.0052	0.0052
198		Y2Y2	0.0308	0.0308	0.0308	0.0308	0.0308	0.0308	0.0308
199		Y3Y3	0.0426	0.0444	0.0444	0.0444	0.0444	0.0444	0.0444
200		WKY1	0.0186	0.0185	0.0179	0.0171	0.0180	0.0189	0.0198
201		WKY2	0.0351	0.0373	0.0395	0.0417	0.0440	0.0462	0.0484
202		WKY3	0.0413	0.0448	0.0475	0.0501	0.0528	0.0555	0.0581
203		Y1Y2	0.0327	0.0306	0.0279	0.0253	0.0253	0.0253	0.0253
204		Y1Y3	0.0385	0.0368	0.0335	0.0303	0.0303	0.0303	0.0303
205		Y2Y3	0.0725	0.0740	0.0740	0.0740	0.0740	0.0740	0.0740
206		Average Line Length	(0.2959)	(0.2954)	(0.2950)	(0.2946)	(0.2942)	(0.2939)	(0.2936)
207		Customers Added in last 10 years	82.60%	82.60%	82.60%	82.60%	82.60%	82.60%	82.60%
208		Trend	12.0000	13.0000	14.0000	15.0000	16.0000	17.0000	18.0000
209									
210	**Product of Parameter and 2013 Values**								
211									
212		Constant	12.788	12.788	12.788	12.788	12.788	12.788	12.788
213		Capital Price / OM&A Price (WK)	(0.089)	(0.095)	(0.100)	(0.106)	(0.111)	(0.117)	(0.123)
214		Customers (Y1)	(0.065)	(0.060)	(0.055)	(0.050)	(0.050)	(0.050)	(0.050)
215		Capacity (Y2)	(0.034)	(0.034)	(0.034)	(0.034)	(0.034)	(0.034)	(0.034)
216		Deliveries (Y3)	(0.030)	(0.031)	(0.031)	(0.031)	(0.031)	(0.031)	(0.031)
217		WKWK	0.001	0.001	0.002	0.002	0.002	0.002	0.002
218		Y1Y1	(0.003)	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)
219		Y2Y2	0.007	0.007	0.007	0.007	0.007	0.007	0.007
220		Y3Y3	0.007	0.007	0.007	0.007	0.007	0.007	0.007
221		WKY1	0.001	0.001	0.001	0.001	0.001	0.001	0.001
222		WKY2	0.000	0.000	0.000	0.000	0.000	0.000	0.000
223		WKY3	0.000	0.000	0.000	0.000	0.000	0.000	0.000
224		Y1Y2	0.003	0.003	0.002	0.002	0.002	0.002	0.002
225		Y1Y3	0.003	0.003	0.002	0.002	0.002	0.002	0.002
226		Y2Y3	(0.014)	(0.015)	(0.015)	(0.015)	(0.015)	(0.015)	(0.015)
227		Average Line Length	(0.078)	(0.078)	(0.078)	(0.078)	(0.078)	(0.078)	(0.078)
228		Customers Added in last 10 years	0.016	0.016	0.016	0.016	0.016	0.016	0.016
229		Trend	0.197	0.214	0.230	0.246	0.263	0.279	0.296
230									
231		Log of Predicted Total Cost / OM&A Price	12.7095	12.7242	12.7405	12.7568	12.7679	12.7791	12.7902
232		Real Predicted Total Cost / OM&A Price	330,889	335,780	341,297	346,888	350,779	354,715	358,698
233		OM&A Price	125.29	128.46	131.70	135.03	138.44	141.94	145.52
234		**Predicted Total Cost**	41,457,453	43,133,170	44,949,463	46,840,052	48,562,137	50,347,768	52,199,311
235									
236									

Section 4: Benchmarking Results

Line Reference Number		2018	2019	2020	2021	2022	2023	2024
237	Actual Cost	41,988,255	43,962,086	45,370,241	46,912,950	48,162,429	49,122,126	30,334,041
238	Predicted Cost	41,457,453	43,133,170	44,949,463	46,840,052	48,562,137	50,347,768	52,199,311
239	Actual less Predicted Cost	530,802	828,916	420,778	72,898	(399,708)	(1,225,642)	(21,865,270)
240	Percentage Difference (Arithmetic for Comparison)	1.28%	1.92%	0.94%	0.16%	-0.82%	-2.43%	-41.89%
241								
242	**Percent Difference (Logarithmic)**	**1.27%**	**1.90%**	**0.93%**	**0.16%**	**-0.83%**	**-2.46%**	**-54.28%**

Appendix 1-34

OEB 2020_Tariff_Schedule_and_Bill_Impact_Model

Instructions for Tabs 3 to 7

Tab	Tab Details
3 - Continuity Schedule	This tab is the continuity schedule that shows all the accounts and the accumulation of the balances a utility has.
4 - Billing Determinant	This tab shows the billing determinants that will be used to allocate account balances and calculate rate riders.
6 - Class A Data Consumption	This is a new tab that is to be completed if there were any Class A customers at any point during the period the GA balance accumulated. The tab also considers Class A/B transition customers. The data on this tab is used for the purposes of determining the GA rate rider, CBR Class B rate rider (if applcable), as well as customer specific GA and CBR charges for transition customers (if applicable).

6.1a - GA Allocation	This tab has been revised. It allocates the GA balance to each transition customer for the period in which these customers were Class B customers and contributed to the GA balance (i.e. former Class B customers who contributed to the GA balance but are now Class A customers and former Class A customers who are now Class B customers contributing to the GA balance).
6.1 - GA	This tab calculates the GA rate rider to be applied to all non-RPP Class B customers (except for the transition customers allocated a customer specific balance in tab 6.1a).
6.2 - CBR	This is a new tab that calculates the CBR Class B rate rider if there were Class A customers at any point during the period that the CBR Class B balance accumulated.
6.2a - CBR_B Allocation	This is a new tab that allocates the CBR Class B balance to each transition customer for the period in which these customers were Class B customers and contributed to the CBR Class B balance (i.e. former Class B customers who contributed to the balance but are now Class A customers and former Class A customers who are now Class B contributing to the balance).
5 - Allocating Def-Var Balances	This tab allocates the Group 1 balances (except GA and CBR Class B if Class A customers exist).
7 - Calculation of Def-Var RR	This tab calculates the Group 1 rate riders, except for GA and CBR Class B (if Class A customers exist)

Step	Details
1	Complete the DVA continuity sche For all Group 1 Accounts, except f the 2017 rate application, DVA ba entering the closing 2014 balance December 31, 2016 regardless of account, start inputting data from (2014) would have information st (2014). The DVA continuity schedu schedule should be provided start
2a	If you had any Class A customers a balances in the 2016 rate applicat If the checkbox is not checked off, tabs 6.1 and 7, complete the tabs If the checkbox is checked off, tab
2b	If the checkbox in step 2a is check during the period that the Accoun If the checkbox is not checked off, 1580 WMS, as part of the general If the checkbox is checked off, the B through a separate rate rider us
3	Confirm the accuracy of the RRR c
4	Review the disposition threshold c
5	This tab is generated when the uti Under #1, enter the year the Acc
6	Under #2a, indicate whether you If no, proceed to #3b in step 8. If yes, #2b and tab 6.1a will be ge Under #2b, indicate whether you If no, proceed to #3a in step 7. If yes, tab 6.2a will be generated.
7	Under #3a, enter the number of t based on the number of custome the customer class during the half customers in tabs 6.1a and 6.2a re number will correspond to the sa

8	did not transition between Class A accordingly for each Class A custo Class B balances to the rate classe
9	This tab is generated when the uti In row 20, enter the total Class B c customers (who were Class A for p customers in the bottom table. Al GA rate rider as calculated in tab 6
10	populated and the GA rate riders a balance accumulated.
11	This tab is generated when the ut Select one of two options pertaini The rest of the information in the any transition customers during th
12	This tab is generated when the uti In row 20, enter the total Class B c (who were Class A for partial and transition customers in the bottom for CBR Class B as this would depe allocated a specific CBR Class B an
13	Review the allocated balances to e calculated after the completion of
14	Enter the proposed rate rider reco populated and the rate riders are

edule.

or Account 1595, start inputting data from the year in which the GL balance was last disposed. For example, if in lances as at December 31, 2015 were approved for disposition, start the continuity schedule from 2015 by s in the Adjustments column under 2014.

whether the account is being requested for disposition in the current application. For each Account 1595 sub- the year the sub-account started to accumulate a balance (i.e. the vintage year). For example, Account 1595 arting in 2014, when the relevant balances approved for disposition were first transferred into Account 1595 ule currently starts from 2011, if a utility has an Account 1595 with a vintage year prior to 2011, then a separate ing from the vintage year.

at any point during the period that the Account 1589 GA balance accumulated (e.g. last disposition was for 2014 ion, current balance requested for disposition accumulated from 2015 to 2016), check off the checkbox in cell

, then proceed to tab 4 and complete the tab as needed. Tab 5 will be calculated accordingly. Then proceed to as needed and the appropriate rate riders will be calculated.
6 relating to Class A customer consumption will be generated, see step 5 to 8 below for further details.

ed off, another checkbox will pop up to the right of the checkbox. If you had any Class A customers at any point t 1580, sub-account CBR Class B balance accumulated (i.e. 2015 and 2016 or 2016), check off the checkbox.
, then the balance in the Account 1580, sub-account CBR Class B will be allocated and disposed with Account DVA rate rider.
n tab 6.2 will be generated. This tab will allocate and dispose the balance in Account 1580 sub-account CBR Class sing information inputted in tab 6. See step 11 below for further details.

data used to populate the tab.

calculation. If the threshold disposition is not met, select whether disposition is still being requested or not in the

ility checks in tab 3 that they have Class A customers during the period that GA balance accumulated.
ount 1589 GA balance was last disposed.

had any customers that transitioned between Class A and B during the period the Account 1589 GA balance accun

nerated. Proceed to #2b.
had any customers that transitioned between Class A and B during the period the Account 1580, sub-account CBR

Proceed to #3a in step 7.

ransition customers during the period the Account 1589 GA balance accumulated. A table will be generated rs. Complete the table accordingly for each transition customer identified (i.e. kWh/kW for half year periods, and year). This data will automatically be used in the GA balance and CBR Class B balance allocation to transition espectively. Each transition customer identified in tab 6, table 3a will assigned a customer number and the me transition customer populated in tabs 6.1a and 6.2a. The data in tab 6 will also be used in the calculation of

\ and B during the period). A table will be generated based on the number of customers. Complete the table mer identified. This data will be used in the calculation of billing determinants in the allocation of GA and CBR s, as applicable.

ility indicates that they have transition customers in tab 6, #2a during the period where the Account 1589 GA

consumption which equals to Non-RPP consumption less WMP consumption and consumption for Class A partial and full year).

l transition customers who are allocated a specific GA amount are not to be charged the general Non-RPP Class B 5.1.

are calculated accordingly based on whether there were any transition customers during the period that the GA

ility checks in tab 3 that they have Class A customers during the period that Account 1580, sub-account CBR Class ng to the the years in which the CBR Class B balance accumulated, either 2015 and 2016, or 2016 only in cell

tab is auto-populated and the CBR Class B rate riders are calculated accordingly based on whether there were ne period that the CBR Class B balance accumulated.

ility indicates that they have transition customers in tab 6, #2b during the period where the CBR Class B balance

consumption which equals to total consumption less WMP consumption and consumption for Class A customers full year).

n table. Note that the transition customers identified for the GA may be different than the transition customers end on the period in which the GA and CBR Class B balances accumulated. All transition customers who are nount are not to be charged the general CBR Class B rate rider.

ensure the allocation is appropriate. Note that the final allocation for Account 1580, sub-account CBR Class B is f tabs 6 to 6.2a.

overy period if different than the default 12 month period. The rest of the information in the tab is auto- calculated accordingly .

nulated.

Class B balance accumulated.

Ontario Energy Board

Tariff Schedule and Bill Impacts Model (2021 Cost of Service Filers)

Quick Link

Ontario Energy Board's 2021 Electricity Distribution Rates Webpage

Version 1.0

Utility Name	Niagara Peninsula Energy Inc.
Assigned EB Number	EB-2020-0040
Name of Contact and Title	Suzanne Wilson, Senior VP Finance
Phone Number	905-353-6004
Email Address	suzanne.wilson@npei.ca
We are applying for rates effective	Friday, January 01, 2021
Rate-Setting Method	**Price Cap IR**
Please indicate the last Cost of Service Re-Basing Year	**2015**

Legend

Pale green cells represent input cells.

Ontario Energy Board

Tariff Schedule and Bill Impacts M

Niagara Peninsula Energy Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2020

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

RESIDENTIAL SERVICE CLASSIFICATION

This class pertains to customers residing in detached, semi-detached or duplex dwelling units, where energy is su phase, 3 wire, 60 hertz, having a nominal voltage of 120/240 volts. Large residential services will include all servic amp. Up to and including 400 amp., 120/240 volt, single phase, three wire. Class B consumers are defined in acc O. Reg. 429/04. Further servicing details are available in the distributor’s Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$
Smart Metering Entity Charge - effective until December 31, 2022	$
Low Voltage Service Rate	$/kWh
Rate Rider for Disposition of Global Adjustment Account (2020) - effective until June 30, 2020	
Applicable only for Non-RPP Customers	$/kWh
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until April 30, 2021	$/kWh
Retail Transmission Rate - Network Service Rate	$/kWh
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh

MONTHLY RATES AND CHARGES - Regulatory Component

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

Ontario Energy Board

Tariff Schedule and Bill Impacts M

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This class pertains to non-residential customers taking electricity at 750 volts or less whose monthly average peak less than, or forecast to be less than, 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$
Smart Metering Entity Charge - effective until December 31, 2022	$
Distribution Volumetric Rate	$/kWh
Low Voltage Service Rate	$/kWh
Rate Rider for Disposition of Global Adjustment Account (2020) - effective until June 30, 2020	
Applicable only for Non-RPP Customers	$/kWh
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until April 30, 2021	$/kWh
Retail Transmission Rate - Network Service Rate	$/kWh
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh

MONTHLY RATES AND CHARGES - Regulatory Component

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

Ontario Energy Board

Tariff Schedule and Bill Impacts M

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater forecast to be equal to or greater than 50 kW but less than 5,000 kW. Class A and Class B consumers are definec accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$
Distribution Volumetric Rate	$/kW
Low Voltage Service Rate	$/kW
Rate Rider for Disposition of Global Adjustment Account (2020) - effective until June 30, 2020	
Applicable only for Non-RPP Customers	$/kWh
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until April 30, 2021	
Applicable only for Non-Wholesale Market Participants	$/kW
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until April 30, 2021	$/kW
Retail Transmission Rate - Network Service Rate	$/kW
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh

Ontario Energy Board

Tariff Schedule and Bill Impacts M

Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh
Standard Supply Service - Administrative Charge (if applicable)	$

Ontario Energy Board

Tariff Schedule and Bill Impacts M

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less whose average peak demand is less tl forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power pac shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electricity demand/consumption of the proposed unmetered load. Class are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditior

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per customer)	$
Distribution Volumetric Rate	$/kWh
Low Voltage Service Rate	$/kWh
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until April 30, 2021	$/kWh
Retail Transmission Rate - Network Service Rate	$/kWh
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh

MONTHLY RATES AND CHARGES - Regulatory Component

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

Ontario Energy Board

Tariff Schedule and Bill Impacts M

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Class B consu defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$
Distribution Volumetric Rate	$/kW
Low Voltage Service Rate	$/kW
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until April 30, 2021	$/kW
Retail Transmission Rate - Network Service Rate	$/kW
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW

MONTHLY RATES AND CHARGES - Regulatory Component

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

Ontario Energy Board

Tariff Schedule and Bill Impacts M

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of T and private roadway lighting operation, controlled by photo cells. Street lighting profile is derived through the use c street lighting meter” that uses a street light control eye, consistent with the model type and product manufacturer currently in service in the Applicant’s distribution area, to simulate the exact daily conditions that the typical street exposed to. This simulated street light load is captured using an interval metering device, and is processed as par distributor’s daily interval meter interrogation, validation and processing procedures. Class B consumers are defin accordance with O. Reg. 429/04. Further servicing details are available in the distributor’s Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$
Distribution Volumetric Rate	$/kW
Low Voltage Service Rate	$/kW
Rate Rider for Disposition of Global Adjustment Account (2020) - effective until June 30, 2020	
Applicable only for Non-RPP Customers	$/kWh
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until April 30, 2021	$/kW
Retail Transmission Rate - Network Service Rate	$/kW
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW

MONTHLY RATES AND CHARGES - Regulatory Component

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

Ontario Energy Board

Tariff Schedule and Bill Impacts M

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independant Electricity System (microFIT program and connected to the distributor's distribution system. Further servicing details are available in t distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$

ALLOWANCES

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

SPECIFIC SERVICE CHARGES

APPLICATION

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

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

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

Customer Administration

Returned cheque (plus bank charges)	$
Legal letter charge	$
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$

Non-Payment of Account (see Note below)

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

Other

Ontario Energy Board

Tariff Schedule and Bill Impacts M

Service call - customer owned equipment	$
Service call - after regular hours	$
Temporary service install & remove - overhead - no transformer	$
Temporary service install & remove - underground - no transformer	$
Temporary service install & remove - overhead - with transformer	$
Specific charge for access to the power poles (with the exception of wireless attachments)	$

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

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

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

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

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

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

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$
Monthly fixed charge, per retailer	$
Monthly variable charge, per customer, per retailer	$
Distributor-consolidated billing monthly charge, per customer, per retailer	$
Retailer-consolidated billing monthly credit, per customer, per retailer	$
Service Transaction Requests (STR)	
Request fee, per request, applied to the requesting party	$
Processing fee, per request, applied to the requesting party	$
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party	
Up to twice a year	$
More than twice a year, per request (plus incremental delivery costs)	$
Notice of switch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019)	$

LOSS FACTORS

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

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

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

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EB-2019-0054

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Ontario Energy Board

Tariff Schedule and Bill Impacts Mo

(2021 Cost of Service Filers)

Update the following rates if an OEB Decision has been issued at the time of completing this application

Regulatory Charges

Effective Date of Regulatory Charges		**January 1, 2020**	**January 1, 2021**
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	0.25

Time-of-Use RPP Prices

As of		November 1, 2019
Off-Peak	$/kWh	0.1010
Mid-Peak	$/kWh	0.1440
On-Peak	$/kWh	0.2080

Smart Meter Entity Charge (SME)

Smart Meter Entity Charge (SME)	$	0.57

Distribution Rate Protection (DRP) Amount (Applicable to LDCs under the Distribution Rate Protection program):	$	36.86

Miscellaneous Service Charges

Wireline Pole Attachment Charge	**Unit**	**Current charge**	**Inflation factor ***	**Proposed charge ** / *****
Specific charge for access to the power poles - per pole/year	$	44.50	2.00%	45.39

Retail Service Charges		**Current charge**	**Inflation factor***	**Proposed charge *****
One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	102.00		102
Monthly fixed charge, per retailer	$	40.80		40.8
Monthly variable charge, per customer, per retailer	$/cust.	1.02		1.02
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.61		0.61
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	-0.61		-0.61
Service Transaction Requests (STR)				0
Request fee, per request, applied to the requesting party	$	0.51		0.51
Processing fee, per request, applied to the requesting party	$	1.02		1.02
Electronic Business Transaction (EBT) system, applied to the requesting party				
up to twice a year		no charge		no charge
more than twice a year, per request (plus incremental delivery costs)	$	4.08		4.08
Notice of switch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019)	$	2.04		2.04

* inflation factor subject to change pending OEB approved inflation rate effective in 2021
** applicable only to LDCs in which the province-wide pole attachment charge applies
*** subject to change pending OEB order on miscellaneous service charges

del

Ontario Energy Board

Tariff Schedule and Bill Impacts Model
(2021 Cost of Service Filers)

In column A, select the rate rider descriptions from the drop-down list in the blue cells. If the proposed rate rider cannot be found in the drop-down list, enter the rate rider description in the green cell provided in column A. The rate rider description must begin with "Rate Rider for". Please note that the following rates/charges are to be entered in the Final Tariff Schedule tab: Monthly Service Charge, Distribution Volumetric Rate and Retail Transmission Rates.
In column B, select the associated unit from the drop-down list.
In column C, enter the rate. All rate riders with a "$" unit should be rounded to 2 decimal places and all others rounded to 4 decimal places.
In column E, enter the expiry date (e.g. April 30, 2020) or description of the expiry date in text (e.g. the effective date of the next cost of service-based rate order).
In column G, choose the sub-total as applicable in the bill impact calculation from the drop-down list for any rate riders entered in the green cells. The sub-total will be populated for the rate riders selected in the blue cells.

RESIDENTIAL SERVICE CLASSIFICATION	UNIT	RATE		DATE (EG: December 31, 2021)	SU
Rate Rider for Recovery of (year) Foregone Revenue	$	0.62	- effective until	12/31/2021	A
Low Voltage Service Rate	$/kWh	0.0014	- effective until	12/31/2021	B
Rate Rider for Disposition of Account 1576	$	-0.09	- effective until	12/31/2021	A
			- effective until		
			- effective until		
			- effective until		
			- effective until		
Rate Rider for Disposition of Deferral/Variance Accounts-Group 2	$	-0.13	- effective until	12/31/2021	A
Rate Rider for Disposition of Deferral/Variance Accounts -Group 1	$/kWh	-0.0009	- effective until	12/31/2021	B
			- effective until		
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			- effective until		

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	UNIT	RATE		DATE (EG: December 31, 2021)	SU
Rate Rider for Disposition of Deferral/Variance Accounts	$/kWh	-0.0011	- effective until	12/31/2021	B
Rate Rider for Disposition of Account 1576	$/kWh	-0.0001	- effective until	12/31/2021	A
Rate Rider for Recovery of (year) Foregone Revenue	$/kWh	0.0005	- effective until	12/31/2021	A
Low Voltage Service Rate	$/kWh	0.0012	- effective until	12/31/2021	B
			- effective until		
			- effective until		
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Rate Rider for Disposition of Account 1557	$/kWh	0.0006	- effective until	12/31/2021	A

Ontario Energy Board

Tariff Schedule and Bill Impacts Model
(2021 Cost of Service Filers)

			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
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			- effective until		

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	UNIT	RATE		DATE (EG: December 31, 2021)	SU
Rate Rider for Disposition of Deferral/Variance Accounts	$/kW	0.2579	- effective until	12/31/2021	B
Rate Rider for Disposition of Deferral/Variance Accounts Applicable only for Non-Wholesale Marke	$/kW	-0.6869	- effective until	12/31/2021	B
Rate Rider for Disposition of Account 1576	$/kW	-0.0490	- effective until	12/31/2021	A
Rate Rider for Recovery of (year) Foregone Revenue	$/kW	0.1555	- effective until	12/31/2021	A
Low Voltage Service Rate	$/kW	0.4776	- effective until	12/31/2021	B
			- effective until		
			- effective until		
Rate Rider for Disposition of Account 1557	$/kW	0.1206	- effective until	12/31/2021	A
			- effective until		
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UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	UNIT	RATE		DATE (EG: December 31, 2021)	SU
Rate Rider for Disposition of Deferral/Variance Accounts	$/kWh	-0.0011	- effective until	12/31/2021	B
Rate Rider for Disposition of Account 1576	$/kWh	-0.0001	- effective until	12/31/2021	A
Low Voltage Service Rate	$/kWh	0.0012	- effective until	12/31/2021	B
			- effective until		
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Ontario Energy Board

Tariff Schedule and Bill Impacts Model

(2021 Cost of Service Filers)

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SENTINEL LIGHTING SERVICE CLASSIFICATION	UNIT	RATE		DATE (EG: December 31, 2021)	SU
Rate Rider for Disposition of Deferral/Variance Accounts	$/kW	-0.3675	- effective until	12/31/2021	B
Rate Rider for Disposition of Account 1576	$/kW	-0.0418	- effective until	12/31/2021	A
Low Voltage Service Rate	$/kW	0.3991	- effective until	12/31/2021	B
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STREET LIGHTING SERVICE CLASSIFICATION	UNIT	RATE		DATE (EG: December 31, 2021)	SU
Rate Rider for Disposition of Deferral/Variance Accounts	$/kW	-0.3890	- effective until	12/31/2021	B
Rate Rider for Disposition of Account 1576	$/kW	-0.0444	- effective until	12/31/2021	A
Rate Rider for Recovery of (year) Foregone Revenue	$/kW	7.6037	- effective until	12/31/2021	A
Low Voltage Service Rate	$/kW	0.3669	- effective until	12/31/2021	B
			- effective until		
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Ontario Energy Board

Tariff Schedule and Bill Impacts Model

(2021 Cost of Service Filers)

			- effective until		
			- effective until		
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microFIT SERVICE CLASSIFICATION	UNIT	RATE		DATE (EG: December 31, 2021)	SU
	$	4.55	- effective until	12/31/2021	
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1_RESIDENTIAL SERVICE CLASSIFICATION_FX_RR_1
1_RESIDENTIAL SERVICE CLASSIFICATION_CBR_2
1_RESIDENTIAL SERVICE CLASSIFICATION_FX_RR_3

1_RESIDENTIAL SERVICE CLASSIFICATION_FX_RR_8
1_RESIDENTIAL SERVICE CLASSIFICATION_CBR_9

2_GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION_CBR_1
2_GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION_CBR_2
2_GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION_CBR_3
2_GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION_CBR_4

2_GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION_CBR_8

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3_GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION_CBR_1
3_GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION_CBR_2
3_GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION_CBR_3
3_GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION_CBR_4
3_GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION_CBR_5

3_GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION_CBR_8

4_UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION_CBR_1
4_UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION_CBR_2
4_UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION_CBR_3

5_SENTINEL LIGHTING SERVICE CLASSIFICATION_CBR_1
5_SENTINEL LIGHTING SERVICE CLASSIFICATION_CBR_2
5_SENTINEL LIGHTING SERVICE CLASSIFICATION_CBR_3

6_STREET LIGHTING SERVICE CLASSIFICATION_CBR_1
6_STREET LIGHTING SERVICE CLASSIFICATION_CBR_2
6_STREET LIGHTING SERVICE CLASSIFICATION_CBR_3
6_STREET LIGHTING SERVICE CLASSIFICATION_CBR_4

7_microFIT SERVICE CLASSIFICATION_FX_RR_1

Niagara Peninsula Energy Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2021

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

EB-2020-0040

RESIDENTIAL SERVICE CLASSIFICATION

This class pertains to customers residing in detached, semi-detached or duplex dwelling units, where energy is supplied single-phase, 3 wire, 60 hertz, having a nominal voltage of 120/240 volts. Large residential services will include all services from 201 amp. Up to and including 400 amp., 120/240 volt, single phase, three wire. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	36.15
Rate Rider for Disposition of Deferral/Variance Accounts-Group 2 - effective until December 31, 2021	$	(0.13)
Rate Rider for Disposition of Account 1576 - effective until December 31, 2021	$	(0.09)
Rate Rider for Recovery of (year) Foregone Revenue - effective until December 31, 2021	$	0.62
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Low Voltage Service Rate	$/kWh	0.0014
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until April 30, 2021	$/kWh	0.0012
Rate Rider for Disposition of Deferral/Variance Accounts -Group 1 - effective until December 31, 2021	$/kWh	(0.0009)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0072
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0052

MONTHLY RATES AND CHARGES - Regulatory Component

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

Niagara Peninsula Energy Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2021
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2020-0040

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This class pertains to non-residential customers taking electricity at 750 volts or less whose monthly average peak demand is less than, or forecast to be less than, 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	43.11
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0157
Low Voltage Service Rate	$/kWh	0.0012
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until April 30, 2021	$/kWh	0.0012
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2021	$/kWh	(0.0011)
Rate Rider for Disposition of Account 1576 - effective until December 31, 2021	$/kWh	(0.0001)
Rate Rider for Recovery of (year) Foregone Revenue - effective until December 31, 2021	$/kWh	0.0005
Rate Rider for Disposition of Account 1557 - effective until December 31, 2021	$/kWh	0.0006
Retail Transmission Rate - Network Service Rate	$/kWh	0.0065
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0045

MONTHLY RATES AND CHARGES - Regulatory Component

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

Niagara Peninsula Energy Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2021

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

EB-2020-0040

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or forecast to be equal to or greater than 50 kW but less than 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	168.64
Distribution Volumetric Rate	$/kW	3.6065
Low Voltage Service Rate	$/kW	0.4776
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until April 30, 2021		
Applicable only for Non-Wholesale Market Participants	$/kW	0.0384
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until April 30, 2021	$/kW	0.4366
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2021	$/kW	0.2579

Niagara Peninsula Energy Inc.
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Rate Rider for Disposition of Deferral/Variance Accounts Applicable only for Non-Wholesale Market Participants - effective until December 31, 2021	$/kW	(0.6869)
Rate Rider for Disposition of Account 1576 - effective until December 31, 2021	$/kW	(0.0490)
Rate Rider for Recovery of (year) Foregone Revenue - effective until December 31, 2021	$/kW	0.1555
Rate Rider for Disposition of Account 1557 - effective until December 31, 2021	$/kW	0.1206
Retail Transmission Rate - Network Service Rate	$/kW	2.6864
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8247

MONTHLY RATES AND CHARGES - Regulatory Component

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

Niagara Peninsula Energy Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2021

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EB-2020-0040

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less whose average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electricity demand/consumption of the proposed unmetered load. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per customer)	$	21.14
Distribution Volumetric Rate	$/kWh	0.0147
Low Voltage Service Rate	$/kWh	0.0012
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until April 30, 2021	$/kWh	0.0012
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2021	$/kWh	(0.0011)
Rate Rider for Disposition of Account 1576 - effective until December 31, 2021	$/kWh	(0.0001)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0065
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0045

MONTHLY RATES AND CHARGES - Regulatory Component

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

Niagara Peninsula Energy Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2021

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EB-2020-0040

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor’s Conditions of Service.

APPLICATION

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

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

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	19.36
Distribution Volumetric Rate	$/kW	24.1590
Low Voltage Service Rate	$/kW	0.3991
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until April 30, 2021	$/kW	0.4079
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2021	$/kW	(0.3675)
Rate Rider for Disposition of Account 1576 - effective until December 31, 2021	$/kW	(0.0418)
Retail Transmission Rate - Network Service Rate	$/kW	1.9889
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.5248

MONTHLY RATES AND CHARGES - Regulatory Component

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

Niagara Peninsula Energy Inc.
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EB-2020-0040

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. Street lighting profile is derived through the use of a “virtual street lighting meter” that uses a street light control eye, consistent with the model type and product manufacturer of devices currently in service in the Applicant’s distribution area, to simulate the exact daily conditions that the typical street light is exposed to. This simulated street light load is captured using an interval metering device, and is processed as part of the distributor’s daily interval meter interrogation, validation and processing procedures. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor’s Conditions of Service.

APPLICATION

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

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

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	0.74
Distribution Volumetric Rate	$/kW	2.8827
Low Voltage Service Rate	$/kW	0.3669
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until April 30, 2021	$/kW	0.4317
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2021	$/kW	(0.3890)
Rate Rider for Disposition of Account 1576 - effective until December 31, 2021	$/kW	(0.0444)
Rate Rider for Recovery of (year) Foregone Revenue - effective until December 31, 2021	$/kW	7.6037
Retail Transmission Rate - Network Service Rate	$/kW	2.0306
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.4018

MONTHLY RATES AND CHARGES - Regulatory Component

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

Niagara Peninsula Energy Inc.

TARIFF OF RATES AND CHARGES

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microFIT SERVICE CLASSIFICATION

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

APPLICATION

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

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

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	4.55

ALLOWANCES

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

SPECIFIC SERVICE CHARGES

APPLICATION

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

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

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Customer Administration

Returned cheque (plus bank charges)	$	20.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account (see Note below)

Late payment - per month (effective annual rate 19.56% per annum or 0.04896% compounded daily rate)	%	1.50

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Reconnection at meter - during regular hours	$	65.00
Reconnection at meter - after regular hours	$	185.00
Reconnection at pole - during regular hours	$	185.00
Reconnection at pole - after regular hours	$	415.00

Other

Service call - customer owned equipment	$	30.00
Service call - after regular hours	$	165.00
Temporary service install & remove - overhead - no transformer	$	500.00
Temporary service install & remove - underground - no transformer	$	300.00
Temporary service install & remove - overhead - with transformer	$	1,000.00
Specific charge for access to the power poles (with the exception of wireless attachments)	$	44.50

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

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

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

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

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

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	102.00
Monthly fixed charge, per retailer	$	40.80
Monthly variable charge, per customer, per retailer	$	1.02
Distributor-consolidated billing monthly charge, per customer, per retailer	$	0.61
Retailer-consolidated billing monthly credit, per customer, per retailer	$	(0.61)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.51
Processing fee, per request, applied to the requesting party	$	1.02
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	4.08
Notice of switch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019)	$	2.04

LOSS FACTORS

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

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0422
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0317

Ontario Energy Board

Tariff Schedule and Bill Impacts Model
(2021 Cost of Service Filers)

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

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

Note:
1. For those classes that are not eligible for the RPP price, the weighted average price including Class B GA through end of May 2017 of $0.1101/kWh (IESO's Monthly Market Report for May 2017, page 22) has been used to represent the cost of power. For those classes on a retailer contract, applicants should enter the contract price (plus GA) for a more accurate estimate. Changes to the cost of power can be made directly on the bill impact table for the specific class.
2. Please enter the applicable billing determinant (e.g. number of connections or devices) to be applied to the monthly service charge for unmetered rate classes in column N. If the monthly service charge is applied on a per customer basis, enter the number "1". Distributors should provide the number of connections or devices reflective of a typical customer in each class.

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

Table 1

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	**Units**	**RPP? Non-RPP Retailer? Non-RPP Other?**	**Current Loss Factor** (eg: 1.0351)	**Proposed Loss Factor**	**Consumption (kWh)**	**Demand kW (if applicable)**	RTSR **Demand or Demand-Interval?**	**Billing Determinant Applied to Fixed Charge for Unmetered Classes (e.g. # of devices/connections).**
RESIDENTIAL SERVICE CLASSIFICATION	kwh	RPP	1.0479	1.0422	750		CONSUMPTION	1
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kwh	RPP	1.0479	1.0422	2,000		CONSUMPTION	1
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kw	Non-RPP (Other)	1.0479	1.0422	65,000	180	DEMAND	1
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kwh	RPP	1.0479	1.0422	250		CONSUMPTION	1
SENTINEL LIGHTING SERVICE CLASSIFICATION	kw	Non-RPP (Other)	1.0479	1.0422	44	0	DEMAND	1
STREET LIGHTING SERVICE CLASSIFICATION	kw	Non-RPP (Other)	1.0479	1.0422	50	0	DEMAND	1
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION								
STANDBY POWER SERVICE CLASSIFICATION								
RESIDENTIAL SERVICE CLASSIFICATION	kwh	Non-RPP (Retailer)	1.0479	1.0422	750		CONSUMPTION	1
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kwh	Non-RPP (Retailer)	1.0479	1.0422	2,000		CONSUMPTION	1
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								

Table 2

RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	Sub-Total						Total	
		A		B		C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	$ 2.88	8.6%	$ 2.33	5.8%	$ 1.97	3.9%	$ 1.58	1.3%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kwh	$ 7.16	10.3%	$ 5.11	6.0%	$ 4.14	3.8%	$ 3.33	1.1%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ 107.49	14.3%	$ 87.22	10.1%	$ 59.84	3.5%	$ 19.90	0.2%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kwh	$ 0.46	1.9%	$ 0.20	0.8%	$ 0.08	0.3%	$ 0.06	0.1%
SENTINEL LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ 1.52	7.4%	$ 1.48	7.1%	$ 1.47	6.8%	$ 1.19	5.5%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ 0.18	9.4%	$ 0.13	5.8%	$ 0.11	4.2%	$ 0.13	1.3%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION -									
STANDBY POWER SERVICE CLASSIFICATION -									
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kwh	$ 2.88	8.6%	$ 2.41	6.1%	$ 2.04	4.1%	$ 1.64	1.5%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - Non-RPP (Retailer)	kwh	$ 7.16	10.3%	$ 5.30	6.3%	$ 4.34	4.0%	$ 3.49	1.3%

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION	
RPP / Non-RPP:	RPP	
Consumption	750	kWh
Demand	-	kW
Current Loss Factor	1.0479	
Proposed/Approved Loss Factor	1.0422	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 33.67	1	$ 33.67	$ 36.15	1	$ 36.15	$ 2.48	7.37%
Distribution Volumetric Rate	$ -	750	$ -	$ -	750	$ -	$ -	
Fixed Rate Riders	$ -	1	$ -	$ 0.40	1	$ 0.40	$ 0.40	
Volumetric Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 33.67**			**$ 36.55**	**$ 2.88**	**8.55%**
Line Losses on Cost of Power	$ 0.1276	36	$ 4.58	$ 0.1276	32	$ 4.04	$ (0.55)	-11.90%
Total Deferral/Variance Account Rate Riders	$ 0.0012	750	$ 0.90	$ 0.0003	750	$ 0.23	$ (0.68)	-75.00%
CBR Class B Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
GA Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Low Voltage Service Charge	$ 0.0005	750	$ 0.38	$ 0.0014	750	$ 1.05	$ 0.68	180.00%
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		750	$ -	$ -	750	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 40.10**			**$ 42.43**	**$ 2.33**	**5.82%**
RTSR - Network	$ 0.0074	786	$ 5.82	$ 0.0072	782	$ 5.63	$ (0.19)	-3.23%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0054	786	$ 4.24	$ 0.0052	782	$ 4.06	$ (0.18)	-4.23%
Sub-Total C - Delivery (including Sub-Total B)			**$ 50.16**			**$ 52.13**	**$ 1.97**	**3.92%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	786	$ 2.67	$ 0.0034	782	$ 2.66	$ (0.01)	-0.54%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	786	$ 0.39	$ 0.0005	782	$ 0.39	$ (0.00)	-0.54%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.1010	488	$ 49.24	$ 0.1010	488	$ 49.24	$ -	0.00%
TOU - Mid Peak	$ 0.1440	128	$ 18.36	$ 0.1440	128	$ 18.36	$ -	0.00%
TOU - On Peak	$ 0.2080	135	$ 28.08	$ 0.2080	135	$ 28.08	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 149.15**			**$ 151.10**	**$ 1.95**	**1.31%**
HST	13%		$ 19.39	13%		$ 19.64	$ 0.25	1.31%
Ontario Electricity Rebate	31.8%		$ (47.43)	31.8%		$ (48.05)	$ (0.62)	
Total Bill on TOU			**$ 121.11**			**$ 122.69**	**$ 1.58**	**1.31%**

In the manager's summary, discuss the reaso

Customer Class:	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	2,000 kWh
Demand	- kW
Current Loss Factor	1.0479
Proposed/Approved Loss Factor	1.0422

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 40.15	1	$ 40.15	$ 43.11	1	$ 43.11	$ 2.96	7.37%
Distribution Volumetric Rate	$ 0.0146	2000	$ 29.20	$ 0.0157	2000	$ 31.40	$ 2.20	7.53%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	2000	$ -	$ 0.0010	2000	$ 2.00	$ 2.00	
Sub-Total A (excluding pass through)			**$ 69.35**			**$ 76.51**	**$ 7.16**	**10.32%**
Line Losses on Cost of Power	$ 0.1276	96	$ 12.22	$ 0.1276	84	$ 10.77	$ (1.45)	-11.90%
Total Deferral/Variance Account Rate Riders	$ 0.0012	2,000	$ 2.40	$ 0.0001	2,000	$ 0.20	$ (2.20)	-91.67%
CBR Class B Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
GA Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
Low Voltage Service Charge	$ 0.0004	2,000	$ 0.80	$ 0.0012	2,000	$ 2.40	$ 1.60	200.00%
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		2,000	$ -	$ -	2,000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 85.34**			**$ 90.45**	**$ 5.11**	**5.98%**
RTSR - Network	$ 0.0067	2,096	$ 14.04	$ 0.0065	2,084	$ 13.55	$ (0.49)	-3.51%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0047	2,096	$ 9.85	$ 0.0045	2,084	$ 9.38	$ (0.47)	-4.78%
Sub-Total C - Delivery (including Sub-Total B)			**$ 109.23**			**$ 113.38**	**$ 4.14**	**3.79%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	2,096	$ 7.13	$ 0.0034	2,084	$ 7.09	$ (0.04)	-0.54%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	2,096	$ 1.05	$ 0.0005	2,084	$ 1.04	$ (0.01)	-0.54%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.1010	1,300	$ 131.30	$ 0.1010	1,300	$ 131.30	$ -	0.00%
TOU - Mid Peak	$ 0.1440	340	$ 48.96	$ 0.1440	340	$ 48.96	$ -	0.00%
TOU - On Peak	$ 0.2080	360	$ 74.88	$ 0.2080	360	$ 74.88	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 372.80**			**$ 376.89**	**$ 4.10**	**1.10%**
HST	13%		$ 48.46	13%		$ 49.00	$ 0.53	1.10%
Ontario Electricity Rebate	31.8%		$ (118.55)	31.8%		$ (119.85)	$ (1.30)	
Total Bill on TOU			**$ 302.71**			**$ 306.04**	**$ 3.33**	**1.10%**

In the manager's summary, discuss the reasoı

Customer Class:	GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	65,000 kWh
Demand	180 kW
Current Loss Factor	1.0479
Proposed/Approved Loss Factor	1.0422

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 109.12	1	$ 109.12	$ 168.64	1	$ 168.64	$ 59.52	54.55%
Distribution Volumetric Rate	$ 3.5671	180	$ 642.08	$ 3.6065	180	$ 649.17	$ 7.09	1.10%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	180	$ -	$ 0.2271	180	$ 40.88	$ 40.88	
Sub-Total A (excluding pass through)			**$ 751.20**			**$ 858.69**	**$ 107.49**	**14.31%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 0.4750	180	$ 85.50	$ 0.0460	180	$ 8.28	$ (77.22)	-90.32%
CBR Class B Rate Riders	$ -	180	$ -	$ -	180	$ -	$ -	
GA Rate Riders	$ -	65,000	$ -	$ -	65,000	$ -	$ -	
Low Voltage Service Charge	$ 0.1612	180	$ 29.02	$ 0.4776	180	$ 85.97	$ 56.95	196.28%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		180	$ -	$ -	180	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 865.71**			**$ 952.94**	**$ 87.22**	**10.08%**
RTSR - Network	$ 2.7628	180	$ 497.30	$ 2.6864	180	$ 483.55	$ (13.75)	-2.77%
RTSR - Connection and/or Line and Transformation Connection	$ 1.9004	180	$ 342.07	$ 1.8247	180	$ 328.45	$ (13.63)	-3.98%
Sub-Total C - Delivery (including Sub-Total B)			**$ 1,705.09**			**$ 1,764.93**	**$ 59.84**	**3.51%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	68,114	$ 231.59	$ 0.0034	67,743	$ 230.33	$ (1.26)	-0.54%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	68,114	$ 34.06	$ 0.0005	67,743	$ 33.87	$ (0.19)	-0.54%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1101	68,114	$ 7,499.30	$ 0.1101	67,743	$ 7,458.50	$ (40.79)	-0.54%
Total Bill on Average IESO Wholesale Market Price			**$ 9,470.28**			**$ 9,487.89**	**$ 17.61**	**0.19%**
HST	13%		$ 1,231.14	13%		$ 1,233.43	$ 2.29	0.19%
Ontario Electricity Rebate	31.8%		$ -	31.8%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 10,701.42**			**$ 10,721.31**	**$ 19.90**	**0.19%**

Customer Class:	**UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION**	
RPP / Non-RPP:	**RPP**	
Consumption	**250**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0479**	
Proposed/Approved Loss Factor	**1.0422**	

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 20.73	1	$ 20.73	$ 21.14	1	$ 21.14	$ 0.41	1.98%
Distribution Volumetric Rate	$ 0.0144	250	$ 3.60	$ 0.0147	250	$ 3.68	$ 0.07	2.08%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	250	$ -	$ (0.0001)	250	$ (0.03)	$ (0.03)	
Sub-Total A (excluding pass through)			**$ 24.33**			**$ 24.79**	**$ 0.46**	**1.89%**
Line Losses on Cost of Power	$ 0.1276	12	$ 1.53	$ 0.1276	11	$ 1.35	$ (0.18)	-11.90%
Total Deferral/Variance Account Rate Riders	$ 0.0012	250	$ 0.30	$ 0.0001	250	$ 0.03	$ (0.28)	-91.67%
CBR Class B Rate Riders	$ -	250	$ -	$ -	250	$ -	$ -	
GA Rate Riders	$ -	250	$ -	$ -	250	$ -	$ -	
Low Voltage Service Charge	$ 0.0004	250	$ 0.10	$ 0.0012	250	$ 0.30	$ 0.20	200.00%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		250	$ -	$ -	250	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 26.26**			**$ 26.46**	**$ 0.20**	**0.77%**
RTSR - Network	$ 0.0067	262	$ 1.76	$ 0.0065	261	$ 1.69	$ (0.06)	-3.51%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0047	262	$ 1.23	$ 0.0045	261	$ 1.17	$ (0.06)	-4.78%
Sub-Total C - Delivery (including Sub-Total B)			**$ 29.24**			**$ 29.33**	**$ 0.08**	**0.28%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	262	$ 0.89	$ 0.0034	261	$ 0.89	$ (0.00)	-0.54%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	262	$ 0.13	$ 0.0005	261	$ 0.13	$ (0.00)	-0.54%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.1010	163	$ 16.41	$ 0.1010	163	$ 16.41	$ -	0.00%
TOU - Mid Peak	$ 0.1440	43	$ 6.12	$ 0.1440	43	$ 6.12	$ -	0.00%
TOU - On Peak	$ 0.2080	45	$ 9.36	$ 0.2080	45	$ 9.36	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 62.41**			**$ 62.49**	**$ 0.08**	**0.12%**
HST	13%		$ 8.11	13%		$ 8.12	$ 0.01	0.12%
Ontario Electricity Rebate	31.8%		$ (19.85)	31.8%		$ (19.87)	$ (0.02)	
Total Bill on TOU			**$ 50.68**			**$ 50.74**	**$ 0.06**	**0.12%**

In the manager's summary, discuss the reasoi

Customer Class:	**SENTINEL LIGHTING SERVICE CLASSIFICATION**	
RPP / Non-RPP:	**Non-RPP (Other)**	
Consumption	**44**	**kWh**
Demand	**0**	**kW**
Current Loss Factor	**1.0479**	
Proposed/Approved Loss Factor	**1.0422**	

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 18.03	1	$ 18.03	$ 19.36	1	$ 19.36	$ 1.33	7.38%
Distribution Volumetric Rate	$ 22.4995	0.12	$ 2.70	$ 24.1590	0.12	$ 2.90	$ 0.20	7.38%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	0.12	$ -	$ (0.0418)	0.12	$ (0.01)	$ (0.01)	
Sub-Total A (excluding pass through)			**$ 20.73**			**$ 22.25**	**$ 1.52**	**7.35%**
Line Losses on Cost of Power	$ 0.1101	2	$ 0.23	$ 0.1101	2	$ 0.20	$ (0.03)	-11.90%
Total Deferral/Variance Account Rate Riders	$ 0.4079	0	$ 0.05	$ 0.0404	0	$ 0.00	$ (0.04)	-90.10%
CBR Class B Rate Riders	$ -	0	$ -	$ -	0	$ -	$ -	
GA Rate Riders	$ -	44	$ -	$ -	44	$ -	$ -	
Low Voltage Service Charge	$ 0.1347	0	$ 0.02	$ 0.3991	0	$ 0.05	$ 0.03	196.29%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		0	$ -	$ -	0	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 21.03**			**$ 22.51**	**$ 1.48**	**7.06%**
RTSR - Network	$ 2.0455	0	$ 0.25	$ 1.9889	0	$ 0.24	$ (0.01)	-2.77%
RTSR - Connection and/or Line and Transformation Connection	$ 1.5881	0	$ 0.19	$ 1.5248	0	$ 0.18	$ (0.01)	-3.99%
Sub-Total C - Delivery (including Sub-Total B)			**$ 21.46**			**$ 22.93**	**$ 1.47**	**6.85%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	46	$ 0.16	$ 0.0034	46	$ 0.16	$ (0.00)	-0.54%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	46	$ 0.02	$ 0.0005	46	$ 0.02	$ (0.00)	-0.54%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1101	44	$ 4.84	$ 0.1101	44	$ 4.84	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 26.74**			**$ 28.21**	**$ 1.47**	**5.49%**
HST	13%		$ 3.48	13%		$ 3.67	$ 0.19	5.49%
Ontario Electricity Rebate	31.8%		$ (8.50)	31.8%		$ (8.97)		
Total Bill on Average IESO Wholesale Market Price			**$ 21.71**			**$ 22.90**	**$ 1.19**	**5.49%**

Customer Class:	STREET LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	50 kWh
Demand	0 kW
Current Loss Factor	1.0479
Proposed/Approved Loss Factor	1.0422

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 1.27	1	$ 1.27	$ 0.74	1	$ 0.74	$ (0.53)	-41.73%
Distribution Volumetric Rate	$ 4.9783	0.13	$ 0.65	$ 2.8827	0.13	$ 0.37	$ (0.27)	-42.09%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	0.13	$ -	$ 7.5593	0.13	$ 0.98	$ 0.98	
Sub-Total A (excluding pass through)			**$ 1.92**			**$ 2.10**	**$ 0.18**	**9.40%**
Line Losses on Cost of Power	$ 0.1101	2	$ 0.26	$ 0.1101	2	$ 0.23	$ (0.03)	-11.90%
Total Deferral/Variance Account Rate Riders	$ 0.4317	0	$ 0.06	$ 0.0427	0	$ 0.01	$ (0.05)	-90.11%
CBR Class B Rate Riders	$ -	0	$ -	$ -	0	$ -	$ -	
GA Rate Riders	$ -	50	$ -	$ -	50	$ -	$ -	
Low Voltage Service Charge	$ 0.1239	0	$ 0.02	$ 0.3669	0	$ 0.05	$ 0.03	196.13%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		0	$ -	$ -	0	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 2.25**			**$ 2.38**	**$ 0.13**	**5.77%**
RTSR - Network	$ 2.0884	0	$ 0.27	$ 2.0306	0	$ 0.26	$ (0.01)	-2.77%
RTSR - Connection and/or Line and Transformation Connection	$ 1.4600	0	$ 0.19	$ 1.4018	0	$ 0.18	$ (0.01)	-3.99%
Sub-Total C - Delivery (including Sub-Total B)			**$ 2.71**			**$ 2.83**	**$ 0.11**	**4.23%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	52	$ 0.18	$ 0.0034	52	$ 0.18	$ (0.00)	-0.54%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	52	$ 0.03	$ 0.0005	52	$ 0.03	$ (0.00)	-0.54%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1101	50	$ 5.51	$ 0.1101	50	$ 5.51	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 8.67**			**$ 8.79**	**$ 0.11**	**1.31%**
HST	13%		$ 1.13	13%		$ 1.14	$ 0.01	1.31%
Ontario Electricity Rebate	31.8%		$ -	31.8%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 9.80**			**$ 9.93**	**$ 0.13**	**1.31%**

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Retailer)
Consumption	750 kWh
Demand	- kW
Current Loss Factor	1.0479
Proposed/Approved Loss Factor	1.0422

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 33.67	1	$ 33.67	$ 36.15	1	$ 36.15	$ 2.48	7.37%
Distribution Volumetric Rate	$ -	750	$ -	$ -	750	$ -	$ -	
Fixed Rate Riders	$ -	1	$ -	$ 0.40	1	$ 0.40	$ 0.40	
Volumetric Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 33.67**			**$ 36.55**	**$ 2.88**	**8.55%**
Line Losses on Cost of Power	$ 0.1101	36	$ 3.96	$ 0.1101	32	$ 3.48	$ (0.47)	-11.90%
Total Deferral/Variance Account Rate Riders	$ 0.0012	750	$ 0.90	$ 0.0003	750	$ 0.23	$ (0.68)	-75.00%
CBR Class B Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
GA Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Low Voltage Service Charge	$ 0.0005	750	$ 0.38	$ 0.0014	750	$ 1.05	$ 0.68	180.00%
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		750	$ -	$ -	750	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 39.47**			**$ 41.88**	**$ 2.41**	**6.10%**
RTSR - Network	$ 0.0074	786	$ 5.82	$ 0.0072	782	$ 5.63	$ (0.19)	-3.23%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0054	786	$ 4.24	$ 0.0052	782	$ 4.06	$ (0.18)	-4.23%
Sub-Total C - Delivery (including Sub-Total B)			**$ 49.53**			**$ 51.57**	**$ 2.04**	**4.12%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	786	$ 2.67	$ 0.0034	782	$ 2.66	$ (0.01)	-0.54%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	786	$ 0.39	$ 0.0005	782	$ 0.39	$ (0.00)	-0.54%
Standard Supply Service Charge								
Non-RPP Retailer Avg. Price	$ 0.1101	750	$ 82.58	$ 0.1101	750	$ 82.58	$ -	0.00%
Total Bill on Non-RPP Avg. Price			**$ 135.17**			**$ 137.20**	**$ 2.03**	**1.50%**
HST	13%		$ 17.57	13%		$ 17.84	$ 0.26	1.50%
Ontario Electricity Rebate	31.8%		$ (42.98)	31.8%		$ (43.63)		
Total Bill on Non-RPP Avg. Price			**$ 109.76**			**$ 111.40**	**$ 1.64**	**1.50%**

In the manager's summary, discuss the reasoi

Customer Class:	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Retailer)
Consumption	2,000 kWh
Demand	- kW
Current Loss Factor	1.0479
Proposed/Approved Loss Factor	1.0422

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 40.15	1	$ 40.15	$ 43.11	1	$ 43.11	$ 2.96	7.37%
Distribution Volumetric Rate	$ 0.0146	2000	$ 29.20	$ 0.0157	2000	$ 31.40	$ 2.20	7.53%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	2000	$ -	$ 0.0010	2000	$ 2.00	$ 2.00	
Sub-Total A (excluding pass through)			**$ 69.35**			**$ 76.51**	**$ 7.16**	**10.32%**
Line Losses on Cost of Power	$ 0.1101	96	$ 10.55	$ 0.1101	84	$ 9.29	$ (1.26)	-11.90%
Total Deferral/Variance Account Rate Riders	$ 0.0012	2,000	$ 2.40	$ 0.0001	2,000	$ 0.20	$ (2.20)	-91.67%
CBR Class B Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
GA Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
Low Voltage Service Charge	$ 0.0004	2,000	$ 0.80	$ 0.0012	2,000	$ 2.40	$ 1.60	200.00%
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		2,000	$ -	$ -	2,000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 83.67**			**$ 88.97**	**$ 5.30**	**6.34%**
RTSR - Network	$ 0.0067	2,096	$ 14.04	$ 0.0065	2,084	$ 13.55	$ (0.49)	-3.51%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0047	2,096	$ 9.85	$ 0.0045	2,084	$ 9.38	$ (0.47)	-4.78%
Sub-Total C - Delivery (including Sub-Total B)			**$ 107.56**			**$ 111.90**	**$ 4.34**	**4.04%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	2,096	$ 7.13	$ 0.0034	2,084	$ 7.09	$ (0.04)	-0.54%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	2,096	$ 1.05	$ 0.0005	2,084	$ 1.04	$ (0.01)	-0.54%
Standard Supply Service Charge								
Non-RPP Retailer Avg. Price	$ 0.1101	2,000	$ 220.20	$ 0.1101	2,000	$ 220.20	$ -	0.00%
Total Bill on Non-RPP Avg. Price			**$ 335.93**			**$ 340.23**	**$ 4.30**	**1.28%**
HST	13%		$ 43.67	13%		$ 44.23	$ 0.56	1.28%
Ontario Electricity Rebate	31.8%		$ (106.83)	31.8%		$ (108.19)		
Total Bill on Non-RPP Avg. Price			**$ 272.78**			**$ 276.27**	**$ 3.49**	**1.28%**

In the manager's summary, discuss the reasoi