EXHIBIT 1:

ADMINISTRATIVE DOCUMENTS

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Application

Exhibit 1: Administrative Documents

2.1.2 Executive Summary

The Applicant is PUC Distribution Inc. referred to in this Application as the "Applicant" or "PUC Distribution". The Applicant is an Ontario corporation with its office in the city of Sault Ste. Marie. The Applicant carries on the business of distributing electricity in its service territory which includes most of Sault Ste. Marie, Batchewana First Nation (Rankin Reserve), Prince Township and parts of Dennis Township. The Applicant distributes electricity to more than 30,000 customers within a service territory that covers 342 square kilometers. Of that service territory, 284 square kilometers are rural and 58 square kilometers are urban. The total population is 73, 368[1].

The Applicant hereby applies to the Ontario Energy Board (the "OEB" or the "Board") pursuant to section 78 of the *Ontario Energy Board Act, 1998* (the "OEB Act") for approval of its proposed distribution rates and other charges, effective May 1, 2018 (the "Application").

The Application has been prepared pursuant to the Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach issued October 18, 2012 (the "RRFE").

Unless specifically stated otherwise in the Application, the Applicant followed Chapter 2 of the OEB's Filing Requirements for Electricity Distribution Rate Applications last revised on July 14, 2017 (the "Filing Requirements") in preparing the Application.

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[1]Statscan Census Profile 2016 Census http://www12.statcan.gc.ca/census-recensement/2016/dp-pd/prof/details/page.cfm?Lang=E&Geo1=CSD&Code1=3557061&Geo2=CD&Code2=3557&Data=Count&SearchText=sault%20ste%20marie&SearchType=Begins&SearchPR=01&B1=All&TABID=1

PUC Distribution has prepared a Consolidated Distribution System Plan ("DSP") in accordance with Chapter 5 of the OEB's Filing Requirements for Electricity Transmission and Distribution Applications.

PUC Distribution has prepared the revenue requirement in accordance with the Board's Cost of Capital Parameter Updates for Rates Effective in 2018 released November 23, 2017.

The Applicant submits the proposed distribution rates contained in this Application are just and reasonable on the following grounds:

(i) the proposed rates for the distribution of electricity have been prepared in accordance with the Filing Requirements;

(ii) the proposed adjusted rates are necessary to meet the Applicant's market based rate of return and PILs (Payments in Lieu of Taxes) requirements;

(iii) Unless otherwise noted in this Application, there are no impacts to any of the customer classes or consumption level subgroups that are so significant as to warrant the deferral of any adjustments being requested by the Applicant;

(iv) the other service charges proposed by the Applicant are the same as those previously approved by the Board, and

(v) Such other and further grounds and material as counsel may advise and this tribunal may permit.

2.1.2.1 Renewed Regulatory Framework for Electricity

The Board's Renewed Regulatory Framework for Electricity ("RRFE") takes a performance-based approach to planning with the four RRFE outcomes of:

- Customer Focus: services are provided in a manner that responds to identified customer preferences;

- Operational Effectiveness: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;

- Public Policy Responsiveness: utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and,

- Financial Performance: financial viability is maintained.

PUC Distribution's Mission, Vision and Core Values align well with the objectives of the RRFE as demonstrated in Table 1-1 below. Customer focus and engagement is a key component of PUC's current and future plans.

Mission: PUC's mission is to provide cost effective, efficient, safe and reliable delivery of high quality energy services and solutions consistent with customer needs and preferences.

Vision: To be recognized as a progressive electric distribution company committed to delivering value, innovation, prosperity and excellence.

Table 1-1 Alignment of PUC Core Values with Board RRFE

PUC Core Value	**RRFE**
Responsive – We believe that to be recognized as the leading service provider we need to not only respond quickly to our customers' needs but also anticipate and be proactive with our service delivery	Customer Focus

Safety: PUC has been and will continue to be a strong advocate for safety within our community. Safety is our top priority and we will never compromise on the safety of our employees or our customers	
Ownership: To promote organizational excellence, everyone is empowered to take individual accountability and inspired to assume personal responsibility within the organization	Operational Effectiveness
Innovative: We believe that in order to succeed in advancing a climate of innovation we must seek out new approaches or technologies, and apply ingenuity and creativity when confronting challenges	Public Policy Responsiveness
Entrepreneurial: We recognize that exploring new business ventures and diversifying our service offerings is the best way to ensure we not only earn a fair return for our shareholder, but grow and add value as a community owned asset.	Financial Performance

In conjunction with the Mission, Vision and Core Values, PUC has set three strategic Focus Areas and Aspirations which are detailed in the table on page 8, in the PUC Distribution's Business Plan attached as Appendix 12.

PUC Distribution has consistently met OEB targets on all service quality metrics and reliability metrics. Moreover, the trend for both metrics is positive with service quality improving over time, and with power outage metrics indicators decreasing over time.

PUC Distribution has been achieving positive trends in service quality and reliability while experiencing a negative performance on its return on equity ("ROE"). The OEB deemed ROE has been 8.98% since 2013, and in 2012 it was 8.57%. PUC Distribution has been more than 300 basis points below the deemed ROE in 2012, 2014, 2015 and 2016. PUC Distribution's actual 2013 OM&A expenditures were $11.2 million compared to the approved amount in rates of $9.95 million. PUC Distribution was required to make these investments in order to meet its regulatory obligations and safely operate and maintain the distribution system.

In 2016, PUC Distribution had an ROE of just 0.98%. Table 1-2 below demonstrates the ROE Performance from 2012 to 2016.

Table 1-2 ROE Performance Deemed vs. Achieved

Year	**2012**	**2013**	**2014**	**2015**	**2016**
% Deemed	8.57	8.98	8.98	8.98	8.98
% Achieved	4.99	7.00	5.47	4.46	0.98
% Difference	3.58	1.98	3.41	4.52	8.00

PUC Distribution is applying for rates because of its poor performance on profitability; this cost of service application will assist PUC Distribution in realigning rates to recover its actual costs.

PUC Distribution is a virtual utility. PUC Distribution has no employees but rather relies on PUC Services to provide the necessary resources at cost to operate the distribution utility. PUC Services Inc. provides billing, operation services, collection, customer service, and administration services to PUC Distribution. Administrative services include payroll, human

resources, accounting, IT services, etc. The management services were provided in accordance with the Management, Operations and Maintenance Agreement, signed January 1, 2001, as amended on November 10, 2011, ("Management Services Agreement") attached as Appendix 1. All fees charged under the Management Services Agreement are determined as "a monthly fee consisting of the direct costs specifically attributable to PUC Distribution plus PUC Distribution's proportionate share (as set forth herein) of the costs incurred by the Manager for the shared services (direct costs and shared costs collectively referred to as the "Costs") incurred by the Manager in the fulfilment of the Manager's obligations."[2]

2.1.3 Administration

2.1.3.1 Certificate of Evidence

Attached as Appendix 13 is a PUC Distribution's Certificate of Evidence.

2.1.3.2 Primary Contact and Representatives

The Applicant:

PUC Distribution Inc.
500 Second Line East, P.O. Box 9000
Sault Ste. Marie, Ontario
P6A 6P2

Primary Application Contact:

Mr. Andrew Belsito, CPA, CMA
Rates and Regulatory Affairs Officer
Telephone: 705-759-3009
Fax: 705-759-6553
Email: andrew.belsito@ssmpuc.com

[2] Management Services Agreement at section 4.1.

The Applicant's Representation:

Borden Ladner Gervais LLP
Bay Adelaide Centre, East Tower
22 Adelaide Street West
Toronto, ON M5H 4E3

Primary Contact:

John A.D. Vellone
Partner
Telephone: 416-367-6730
Fax: 416-367-6749
Email: jvellone@blg.com

Bruce Bacon, Senior Utility Rate Consultant
Telephone: 416-367-6087
Fax: 416-361-7366
Email: bbacon@blg.com

2.1.3.3 Website and Social Media

The Application and related materials will be posted on PUC Distribution's website and will be available for viewing at the following internet address:

http://www.ssmpuc.com/index.cfm?fuseaction=content&menuid=106&pageid=1092

PUC Distribution also has a Facebook and Twitter account to communicate information to customers. These accounts can be found at the following internet addresses:

https://www.facebook.com/SSMPUC

https://twitter.com/ssmpuc

2.1.3.4 Impacted Customers

Residents, businesses and institutions in the City of Sault Ste. Marie (with exception of all or part of six municipal addresses as listed on its distribution license), Township of Prince, Rankin Reserve, Township of Dennis (concessions 3, 4 and 5) who receive electricity distribution services from PUC Distribution will be affected by the Application. This includes customers within the following rate classes:

- Residential
- General Service Less Than 50 kW
- General Service 50 to 4999 kW
- Unmetered Scattered Load
- Sentinel Lighting
- Street Lighting

2.1.3.5 Publication of Notice of Hearing

We recommend that the Application and related materials be published on the following website, http://www.ssmpuc.com/index.cfm?fuseaction=content&menuid=106&pageid=1092 and if the OEB decides that publication in a paper is necessary then we recommend the Sault This Week. The Sault This Week is a weekly newspaper with circulation to 33,425 homes and covers PUC Distribution's entire service territory.

2.1.3.6 Bill Impacts

In Table 1-3 below, in addition to the 750kWh per month PUC Distribution has included the consumption profile of 908kWh per month, representing the average residential customer in Sault Ste. Marie and 308kWh per month, representing the lowest 10% of users in terms of consumption. Sault Ste. Marie's colder winters, and widespread use of electric heaters in homes contributes to the higher average consumption profile. The electric heaters are difficult to replace with forced air systems due to the cost and construction difficulties associated with installing the necessary duct work.

Table 1-3 Bill Impacts

Rate Class	Number of Customers/ Connections	Monthly kWH	Monthly kW	$ Change	% Change
Residential	1	308		$5.58	10.35%
Residential	1	750		$1.94	1.86%
Residential	1	908		$1.27	0.84%
General Service < 50 kW	1	2,000		$1.28	0.45%
General Service ≥ 50 to 4999 kW	1	52,195	130	-$138.89	-1.57%
Street Lights	8,070	363,540	1825	-$19,423.71	-16.01%
Sentinel Lights	1	55	1	$4.92	11.43%
Unmetered Scattered Load	1	3,450		-$1.49	-0.23%

2.1.3.7 Form of Hearing Requested

The bill impacts resulting from this Application are within the Board's requirements, as shown in Section 2.1.3.5 above. Accordingly, PUC Distribution requests that this Application be disposed of by way of a written hearing in order to expedite the proceeding.

2.1.3.8 Requested Effective Date

The requested effective date for the application is May 1, 2018.

In the event that the Board is unable to provide a Decision and Order in this Application for implementation by the Applicant as of May 1, 2018, the Application requests that the Board declare its current rates interim, effective May 1, 2018, pending the implementation of the Board's Rate Order for the 2018 rate year.

In the event that the effective date does not coincide with the Board's decided implementation date for 2018 distribution rates and charges, PUC Distribution requests permission to recover the incremental revenue from the effective date to the implementation date.

2.1.3.9 Statement of Deviations

PUC Distribution has adhered to Board's filing documents listed below in preparing this application:

- Chapter 2 of the Board's "Filing Requirements for Electricity Distribution Rate Applications – 2016 Edition for 2017 Rate Applications – Chapter 2: Cost of Service", issued July 14, 2017;
- The Board's "Filing Requirements for Electricity Transmission and Distribution Applications – Chapter 5: Consolidated Distribution System Plan Filing Requirements", issued March 28, 2013; and
- The Board's Cost of Capital Parameter Updates for Rates Effective in 2018 released November 23, 2017.

2.1.3.10 Statement of Changes to Methodologies

The Accounting Standards Board ("AcSB") deferred mandatory adoption of International Financial Reporting Standards ("IFRS") for qualifying rate regulated entities to January 1, 2015. PUC Distribution confirms that it implemented the regulatory accounting changes for depreciation and overhead capitalization in 2013. PUC Distribution has prepared this Application on the IFRS basis, as required.

In 2014, PUC Distribution revised the methodology used in accounting for the office building usage fees from the methodology used in 2013.

- In the 2013 actual, the total building usage fees were billed to PUC Services and an offsetting expense for PUC Distribution's usage of a portion of the building was billed back to PUC Distribution and included in expenses.

- In the 2013 cost of service application, only the net amount of the expense was included with no offsetting revenue.

- The treatment results in a variance in both revenue and expense with no net difference overall (see Table 1-4 below). The treatment was changed in the 2014 actual and onward to reflect the treatment in the cost of service rate application.

Table 1-4 – Building Usage Fee

	2013	2014
Building Usage Fee from PUC Distribution to PUC Sevices	$2,283,187.80	$1,248,614.41
Building Usage Fee from PUC Services to PUC Distribution	$1,042,725.00	$0.00
Net Building Usage Fee Revenue to PUC Distribution	**$1,240,462.80**	**$1,248,614.41**

PUC Distribution transitioned from CGAAP to IFRS for year-end 2015.

2.1.3.11 Identification of Board Directives from Previous Board Decisions

PUC Distribution has not received any other utility specific directions from the Board since submitting its last Cost of Service Application (EB-2012-0162) for the July 1, 2013 distribution rates.

PUC Distribution established Account 1508, Other Regulatory Assets, sub-account Productivity Initiatives Variance Account. This account has been used to record the notional revenue in the amount of $400,000 collected from PUC Distribution's customers and related expenditures from July 1, 2013 to April 30, 2017.

PUC Distribution has a corporate commitment to seeking new ways of improving its productivity and efficiency. As part of the 2013 Cost of Service Application settlement agreement PUC Distribution agreed to ring-fence an average amount of $100,000 per year, totaling $400,000, of PUC Distribution's OM&A monies and/or revenue requirement on capital expenditures, to be spent in the period from the effective date of the rates arising out of this Application through April 30, 2017 on furthering PUC Distribution's productivity and efficiency. The OM&A expenditures are included in, and not in addition to, the Board-approved OM&A amount.

The amount spent each year, and the projects on which it was spent, was to be at the discretion of PUC Distribution. Expenditures in this regard may include, without limitation, studies and/or projects involving external consultants, although studies and/or projects using PUC Distribution's internal resources are also permitted. The studies and/or projects may relate, again without limitation, to matters such as:

- Cost reductions in billing, possibly through the increased use of online billing and bill payment;
- Reductions in other administrative costs;

- Reducing OM&A per customer;
- Time-of-use data usage for outage management;
- Time-of-use data for maintenance planning;
- Implementation of electronic Daily Service Order system;
- Meter-to-Cash Business Process Review;

New studies and/or projects could be allocated to this $400,000 total expenditure, and previously planned studies and/or projects could be implemented using this proposed $400,000 total expenditure.

The $400,000 ring fenced amount was used for the following projects undertaken to manage costs and improve service to customers:

- Productivity Improvement Project led by the consulting firm Focused Management Resources (FMR)
- Interactive Voice Response (IVR) system
- Upgraded Telephone System
- Automated Vehicle Locator (AVL)
- Mobile Work Orders (MCare)
- Time of Use Data Usage
- Website Refresh
- Ontario One Call implementation
- Customer Connect implementation

- Server virtualization
- Computer auto shutdown
- CIS software upgrade (CARE)

Interactive Voice Response (IVR) system - The IVR system allows recorded notifications to be sent to specified groups of customers. The IVR is used in the collection of accounts in place of sending a field service rep to a service address and has resulted in reduced collection charges to customers that are already experiencing difficulties paying their bills. It is also used to notify specific customers in advance of planned outages.

Upgraded Telephone System – PUC Distribution's telephone system was upgraded to be capable of providing a standard message to customers in the event of an outage. During a widespread outage, the volume of calls made it impossible to respond to customers and provide information on the outage. The new system provides a message to in-calling customers regarding the area of the outage and indicating that PUC Distribution is aware of the outage. The automated system allows staff to focus on restoring power which results in reduced outage time.

Automated Vehicle Locator (AVL) – PUC Distribution implemented an AVL system; a GIS tracking system used primarily to provide the location of company vehicles. The system is used to dispatch the nearest available vehicle in the event of a customer request or emergency. In addition, the AVL system is a valuable piece of PUC Distribution's Lone Worker Program and is used as a tool to determine fuel tax rebates.

Mobile Work Orders (MCare) – The mobile work order system is currently being used by the meter department. Upon receiving a customer request, an electronic service order is initiated by the customer care department. The electronic order is dispatched to a field service representative's (FSR) tablet out in the field. The FSR completes the order and updates the status of the order in real time. Paper orders are no longer used in the meter department increasing accuracy, eliminating duplicate work and data errors and reducing paper use and scanning.

Efficiency is improved for Customer Care staff due to the ability to check the status of an order electronically which allows quicker response to customer enquiries.

Productivity Study - The Productivity Improvement Project commenced in 2014 and was led by the consulting firm Focused Management Resources (FMR). The study's main focus was to improve scheduling and tracking of electrical work.

Areas of development and implementation included, work scheduling, improved transformer tracking, creating protocols for use of the enterprise software in Engineering, procedure changes in Metering, improved material handling, recording and reporting in Stores, and the locate process was simplified in Line Operations. Efficiencies gained include the elimination of the Dispatcher position and other items as discussed in this section.

Office in the Truck – This project was launched in the spring of 2015 and was designed to electronically connect employees in the field to the office. The implementation has improved communication (photos, videos, text, and email). Remote connectivity assists in trouble-shooting in the field using internet, electronic SOPs, etc. This has reduced calls back to supervisors and trips back to the office from the field. The introduction of electronic forms and books has reduced paper handling, the time and cost of printing books (USF standards, electric system feeder books). Field access to the GIS system has proven to be beneficial.

Time of Use Data Usage – Time of use data, through the Metersense program is being utilized to proactively respond to outages. Prior to the use of the smart meter data, notification of outages was initiated by customers. By using the smart meter data, crews can be dispatched quicker and the area of outage can be more readily ascertained. A report has also been created that provides minimum, maximum and average voltage levels by customer. The data has been used to identify beneficial locations to install voltage regulators which have improved a customer's power quality.

Ontario One Call - Over the historical period, locate request volumes have increased greatly due in part to the exposure brought about by legislation and the ease with which locates can now be requested. As a result, PUC Distribution has had to revise its processes to manage this

increased workload, including, purchasing software and hardware and integration of other business systems. The efficiencies gained have resulted in less overtime than would have been the case without the revised processes.

Customer Connect - Enhanced web based self-serve options which lead to reduced customer enquiries arising through walk in traffic or phone calls. Self-serve options include balance and billing history, TOU consumption trending, e-billing options. Planned future enhancements include bill payment options, online chat portal, online service agreements and service requests.

Server virtualization – PUC Distribution has restructured our server configuration by using virtualization to reduce hardware required. Virtualization provides the ability to run multiple applications and operating systems independently on a single server. This is completed by introducing a layer over the physical server. This layer partitions the server into separate areas that the virtual servers then run on. By implementing server virtualization, hardware can be added dynamically, there are reductions in operations costs, over-provisioning is avoided and one can consolidate hardware.

Table 1-5 below shows the expenditures for the productivity initiatives.

Table 1-5 – Productivity Initiatives

Description	Expenditure
Interactive Voice Response System (IVR)	$ 57,700.00
Upgraded Phone System	$42,000.00
Automated Vehicle Locator (AVL)	$57,300.00
Mobile Work Orders (Mcare)	$29,100.00
Productivity Study	$150,500.00
Office in the Truck	$71,900.00
Time of Use Data Usage	2,800.00
Ontario One Call	$11,400.00
Customer Connect	$30,600.00
Server Virtualization	$90,500.00
Total	**$543,800.00**

PUC Distribution confirms that it bills all customers on a monthly basis in accordance with the Board's Distribution System Code Amendment on April 15, 2015.

2.1.3.12 Information on Conditions of Service

PUC Distribution's current conditions of service are found at:
http://www.ssmpuc.com/index.cfm?fuseaction=content&menuid=64&pageid=1057

2.1.3.13 Conditions of Service & Tariff of Rates and Charges

The current version of PUC Distribution's Conditions of Service is available on PUC's website at:

http://www.ssmpuc.com/index.cfm?fuseaction=content&menuid=64&pageid=1057

PUC Distribution confirms that there are no rates or charges listed in the Conditions of Service that are not on the Tariff of Rates and Charges.

2.1.3.14 Corporate and Utility Organizational Structure

PUC Inc. is a holding company that is 100% owned by its shareholder, the Corporation of the City of Sault Ste. Marie. PUC Distribution Inc. is a subsidiary of PUC Inc. and PUC Services Inc. is also 100% owned by the Corporation of the City of Sault Ste. Marie. There are no employees in PUC Distribution Inc. As part of the management service contract with PUC Services Inc., PUC Services Inc. provides the workforce necessary to operate PUC Distribution. Collective agreements with the union employees in PUC Services Inc. are in effect until April 30, 2018.

PUC Services Inc. is an integrated utility service provider. PUC Services Inc. provides services to its affiliated companies at cost. In addition to providing services to PUC Distribution, services are provided to the Public Utilities Commission on the same terms as that of the affiliate.

PUC Services Inc. also provides services to entities outside the affiliated group – water treatment, wastewater treatment, and billing and customer care services under a number of contracts. These services are provided at rates negotiated between the parties, but in all cases are on a for-profit basis.

PUC Distribution Inc. is the local distribution company which provides regulated services in its service territory. The company owns the distributions assets (land and land rights, poles, conduit, conductors, transformers and meters) and operates the distribution system through an affiliated company – PUC Services Inc. Direct services from PUC Services Inc. to PUC Distribution Inc., such as capital additions or maintenance of the distribution system, are charged at cost. Services such as billing, customer care, administration, etc., which are provided by PUC Services Inc. to all the affiliates are charged at a cost using allocation factors based on the type of shared service provided.

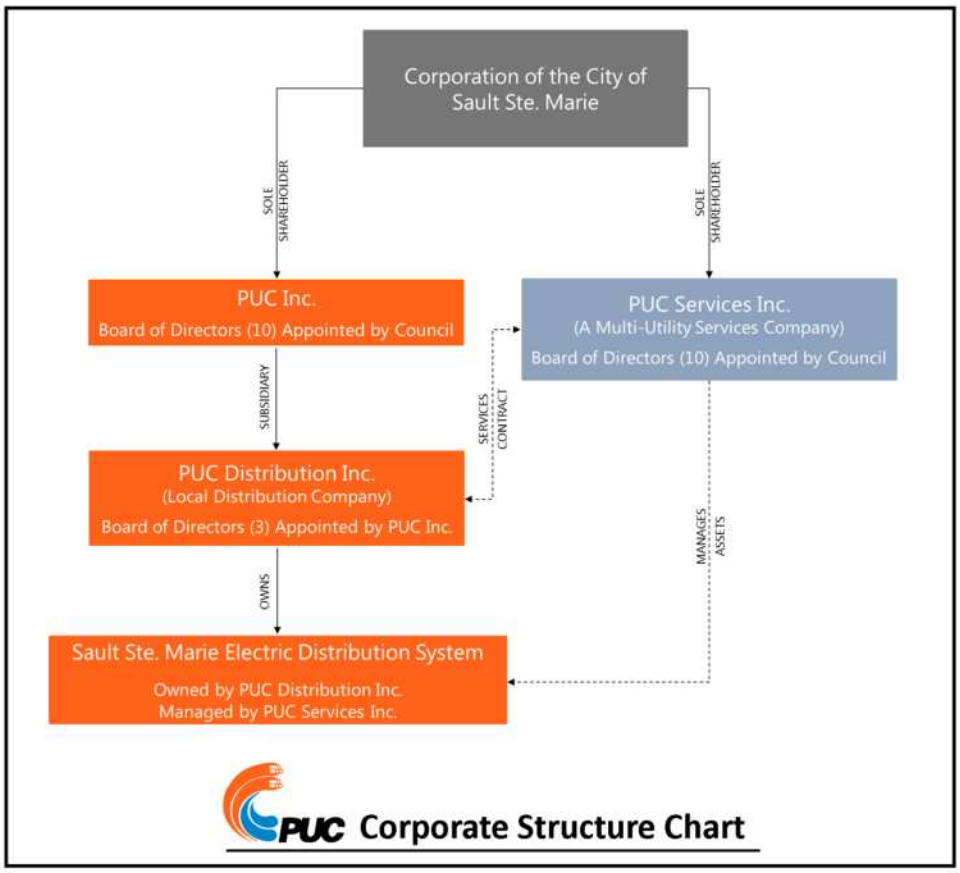
The fees paid by PUC Distribution Inc. to PUC Services Inc. are determined annually, in compliance with the Affiliate Relationships Code. See Management Services Agreement attached as Appendix 1.

The board of directors of both PUC Inc. and PUC Services Inc. are appointed by Sault Ste. Marie's city council. Currently there are 9 board members and one vacancy. PUC Inc. appoints 3 board members to PUC Distribution Inc.'s board of directors, of which 1 is an independent member.

The board of directors has the authority and obligation to protect and enhance the assets (tangible, intangible, human resources) of PUC Distribution in the interest of the stakeholders (Shareholder, customers, employees, suppliers, and community) and is responsible under law for overseeing the actions of management.

The executive team at PUC Distribution is comprised of the President and Chief Executive Officer, Vice President of Customer Engagement and Business Development, Vice President of Finance and Corporate Support and the Vice President of Operations and Engineering. The executives are employed by PUC Services Inc. and allocated to PUC Distribution. There are no planned changes to corporate or operational structure, including no planned changes to legal organization or control. The executive team at PUC Distribution reports to the board of directors of PUC Distribution, which in turn reports to the board of directors of PUC Inc.

Figure 1 PUC Corporate Structure



2.1.3.15 List of Specific Approvals Requested

IN THE MATTER OF the Ontario Energy Board Act, 1998, S.O. 1998, c.15, 3 Schedule B, as amended (the "OEB Act");

AND IN THE MATTER OF an Application by PUC Distribution Inc. ("**PUC Distribution**" or "**the Applicant**") under Section 78 of the OEB Act to the Ontario Energy Board (the "**OEB**" or "**the Board**") for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2018 (the "**Application**").

In this Application PUC Distribution is requesting the following approvals:

- Approval to charge rates effective May 1, 2018 to recover a revenue requirement of $22,081,244 which includes a revenue deficiency of $3,679,687 as set out in Exhibit 6;
- Approval of the proposed loss factor of 1.0481 as set out in Exhibit 8;
- Approval to charge a Retail Transmission Network Service rate as proposed and described in Exhibit 8;
- Approval to continue to charge Wholesale Market Service Charge;
- Approval to continue the Specific Service Charges and Transformer Allowance;
- Approval to dispose of Account 1508, Other Regulatory Assets, sub-account Productivity Initiatives Variance Account;
- Approval of the updated province-wide fixed monthly charge of $5.40 for MicroFIT Generator Service Classification;
- Approval of the rate riders for a one year disposition of the Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA") and Lost Revenue Adjustment Mechanism ("LRAM") for lost revenue for the 2011-2014 program years, with persistence from January 1, 2011 to December 31, 2014. For additional information, please refer to Exhibit 4;
- Approval of the DSP as outlined in Exhibit 2, Appendix 2; and
- Approval of the rate riders for a one year disposition of the Group 1 and Group 2 and Other Deferral and Variance Accounts as detailed in Exhibit 9.

2.1.3.16 Materiality Threshold

Chapter 2 of the Filing Requirements issued by the Board on July 20, 2017 sets out the materiality levels based on the magnitude of the revenue requirement. PUC Distribution's revenue requirement is greater than $10 million and less than $200 million, therefore its materiality level is 0.5% of distribution revenue requirement. PUC Distribution's materiality threshold for the 2018 Test Year is $110,406 as provided in Table 1-6 below. PUC Distribution has used a threshold of $110,406 for assessing materiality for the purposes of this Application.

Table 1-6 – Materiality Threshold for the 2018 Test Year

Description	**2018 Test Year**
Distribution Service Revenue Requirement	$22,081,244
Materiality Threshold	0.5%
Materiality Calculated	$110,406
Materiality Used	$110,406

2.1.4 Distribution System Overview

2.1.4.1 Description of Service Area

PUC Distribution is a local distribution company serving more than 33,000 customers in the City of Sault Ste. Marie (with exception of all or part of six municipal addresses as listed on its distribution license), Township of Prince, Rankin Reserve, and Township of Dennis (concessions 3, 4 and 5) as outlined in Figure 2 below.

Figure 2 - PUC Distribution Service Area

Service Area:	**Description of the Applicant:**
COMMUNITY SERVED:	City of Sault Ste. Marie (with exception of all or part of six municipal addresses as listed on its distribution license), Township of Prince, Rankin Reserve, and Township of Dennis (concessions 3, 4 and 5)
TOTAL SERVICE AREA:	342 square kilometers
RURAL SERVICE AREA	284 square kilometers
URBAN SERVICE AREA	58 square kilometers
DISTRIBUTION TYPE:	Electricity Distribution
MUNICIPAL POPULATION:	73,368

A map of PUC Distribution's service territory is provided in Appendix 9.

PUC Distribution owns, operates and maintains approximately 621 kilometers of overhead primary distribution circuits, and 156 kilometers of underground primary distribution circuits.

PUC Distribution owns and operates two transformer stations which step down power received from the transmitter at 115kV to 34.5kV. The 34.5kV feeders supply a total of 14 distribution stations which step down power to 12.5kV and 4.2kV. PUC Distribution employs approximately 430 km of 3-phase and approximately 270 kms of 1-phase overhead lines operating at 115kV, 34.5kV, 12.5kV, 7.2kV, 4.2kV, 2.4kV and low voltage. The underground distribution network consists of approximately 73 km of 3-phase cable circuits and approximately 83 km of 1-phase cable circuits. There are approximately 12,600 wood poles and 80 other types of poles, 6,622 transformers and 33,417 revenue meters in service.

2.1.4.2 Host/Embedded Distributor

PUC Distribution is neither a host distributor nor an embedded distributor.

2.1.4.3 Transmission or High Voltage Assets

PUC Distribution has transmission assets (>50kV) deemed by the Board as distribution assets. PUC Distribution has included the OEB determination on distribution assets dated October 3, 2000 (ED-1999-0161) in Appendix 2.

PUC Distribution is not asking the OEB to deem any new transmission assets as distribution assets in this Application.

2.1.5 Application Summary

2.1.5.1 Revenue Requirement

PUC Distribution requests a service revenue requirement for 2018 in the amount of $22,081,245. Based on the projected load forecast and customer growth for the 2018 Test Year, PUC Distribution has estimated a revenue deficiency of $3,679,687 based on its current rates. The computation of the revenue deficiency is shown in Exhibit 6. Therefore, PUC Distribution seeks the OEB's approval to revise its electricity distribution rates. The rates proposed to recover its projected revenue requirement and other relief sought are set out in Exhibit 8.

The 2018 service revenue requirement represents an increase of $3,239,896 or 17.20% over the 2013 Board-approved amount of $18,841,349.[3]

[3] Board Decision and Rate Order EB-2012-0162,dated July 4, 2013

The main drivers of the revenue requirement changes from the 2013 Board-approved amount are:

- To provide a reasonable rate of return to the shareholder, the city of Sault Ste. Marie;
- Recovery of PUC Distribution costs to provide distribution services. Cost recovery is necessary to account for:
    - Increased depreciation as a result of capital expenditures since last Cost of Service ("COS") application;
    - Increased rate base, therefore, increased return as a result of capital expenditures since last COS application, and
    - Increased taxable income causing an increase in PILs payable.
- The funds necessary to service PUC Distribution's debt;
- Maintain current capital investment levels in infrastructure to ensure a safe, reliable distribution system;
- Continue with operating expenses necessary to maintain and operate the distribution system, meet customer service expectations and ensure regulatory compliance. These include:
    - Additional MIST metering for general service customers;
    - Increased OEB fees;
    - Increased bad debt expense;
    - Increased TOU billing expenses;
    - Increased regulatory rate filing costs;

- Additional transformer PCB testing.

- Maintain current staffing requirements, including training and preparing for succession planning.

2.1.5.2 Budgeting and Accounting Assumptions

Statement of Accounting Standard Used

PUC Distribution transitioned to IFRS on January 1, 2015 and restated 2014 Financial Statements to IFRS. This Application is being filed using MIFRS Accounting Standards. Historical years are represented under the following Accounting Standards: 2013 using CGAAP and MIFRS 2014 through to 2018.

The budget forecast for the 2018 Test year was prepared and approved by management in November 2017.

PUC Distribution compiles budget information for the three major components of the budgeting process: revenue forecasts, operating and maintenance expense forecast, and capital budget forecast. This budget information is compiled for the Test Year. The below Table 1-7 details the actual number of customers per year along with the inflation rate.

Table 1-7 Inflation and Customer Growth

	2013	2014	2015	2016	2017
Actual Number of	33,377	33,374	33,396	33,421	33,517[4]

[4] Quarterly average for each year from load forecast

Customers					
Inflation	1.6%	1.7%	1.6%	2.1%	1.9%

The inflation rate assumed for labour is 2% and 0% for non-labour for the test year. While PUC Distribution recognizes that the IPI for a rate application in 2018 is 1.2%, PUC Distribution has reduced the non-labour inflation rate to 0% for budgeting purposes, to account for the expected operating efficiencies which will be achieved in 2018.

2.1.5.3 Load Forecast Summary

PUC Distribution's load forecast is weather normalized and considers factors such as historical power purchased load, weather, calendar related factors, number of customers and CDM activity. As outlined in Exhibit 3, PUC Distribution has used the same regression analysis methodology approved by the OEB in its 2013 Cost of Service ("COS") application (EB-2012-0162). The regression analysis was conducted on historical electricity purchases to produce an equation that will predict weather normalized power purchases in 2018. The weather normalized purchased energy forecast is adjusted by a historical loss factor to produce a weather normalized billed energy forecast which is allocated to rate class using historical billing data by rate class.

Based on the load forecast methodology, the total billed 2018 Test Year kWh forecast is 642,873,897 which is an 8.6% decrease over the PUC Distribution's 2013 OEB Approved kWh billed forecast of 703,408,249. The 2013 forecast of 703,408,249 was never achieved from 2013 to 2016. As a result, the 2018 forecast has been developed to be more in line with the results from 2013 and 2016 along with an adjustment for CDM to reflect the expected results from 2017 and 2018 programs in 2018.

The 2018 forecast of customers/connections by rate class was determined using a geometric mean analysis for all rates classes. The expected number of customers/connections for the 2018

Test Year is 42,026 which is an 0.8% decrease compared to the 2013 OEB Approved customers/connections of 42,383.

2.1.5.4 Rate Base and DSP

The capital budget forecast for 2018 is influenced, among other factors, by PUC Distribution's priority to maintain adequate security of supply to meet customer needs, as well as to replace end-of-life assets. Major cost drivers for the DSP in 2018 are:

- Work on an additional substation that is scheduled to commence in 2018;
- System renewal and expansion;
- Customer connections and regulatory requirements; and
- System growth and planning criteria;

The rate base used for the purpose of calculating the revenue requirement used in this application is $99,603,703 and is comprised of the average of the balances at the beginning and the end of the 2018 Test Year, plus a working capital allowance, which is 7.5% of the sum of the cost of power and controllable expenses.

PUC Distribution has provided its rate base calculations for the years 2013 Board Approved to 2018 Test Year below in Table 1-8. PUC Distribution has calculated its 2018 rate base as $99,603,703 (please see Exhibit 2).

The 2013 Board approved rate base for the 2013 Test Year was $90,511,645. The cumulative change in rate base was $9,092,058 which is a 10% increase.

Table 1-8 Actual vs. 2018 Approved Rate Base Variances

Description	2013 OEB Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test Year
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Gross Fixed Assets, Opening Balance		$ 128,112,004	$ 82,778,268	$ 89,439,316	$ 95,587,873	$ 101,126,227	$ 105,808,148
Gross Fixed Assets, Closing Balance		$ 134,056,897	$ 89,439,316	$ 95,587,873	$ 101,126,227	$ 105,808,148	$ 111,166,503
Average Gross Fixed Assets	**$ 132,327,511**	**$ 131,084,451**	**$ 86,108,792**	**$ 92,513,595**	**$ 98,357,050**	**$ 103,467,188**	**$ 108,487,326**
Accumulated Depreciation, Opening Balance		$ 51,244,324	$ -	$ 3,366,973	$ 6,669,872	$ 10,213,863	$ 13,877,445
Accumulated Depreciation, Closing Balance		$ 51,278,631	$ 3,366,973	$ 6,669,872	$ 10,213,863	$ 13,877,445	$ 17,661,400
Average Accumulated Depreciation	**$ 51,060,741**	**$ 51,261,478**	**$ 1,683,487**	**$ 5,018,423**	**$ 8,441,868**	**$ 12,045,654**	**$ 15,769,423**
Average Net Book Value	**$ 81,266,770**	**$ 79,822,973**	**$ 84,425,306**	**$ 87,495,172**	**$ 89,915,183**	**$ 91,421,534**	**$ 92,717,903**
Working Capital	$ 77,040,626	$ 81,010,952	$ 81,231,909	$ 89,178,814	$ 93,220,505	$ 87,825,455	$ 91,810,701
Working Capital Allowance (%)	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	7.50%
Working Capital Allowance	**$ 9,244,875**	**$ 9,721,314**	**$ 9,747,829**	**$ 10,701,458**	**$ 11,186,461**	**$ 10,539,055**	**$ 6,885,803**
Rate Base	**$ 90,511,645**	**$ 89,544,287**	**$ 94,173,135**	**$ 98,196,630**	**$ 101,101,643**	**$ 101,960,588**	**$ 99,603,706**

Table 1-9 below summarizes the planned capital expenditures for the years 2018-2022.

Table 1-9 Planned Capital Expenditures

CATEGORY	Forecast Period (planned)				
	2018	2019	2020	2021	2022
System Access	1,511,028	1,615,276	2,086,480	1,603,804	1,560,434
System Renewal	3,761,033	6,905,898	3,296,444	4,532,889	7,092,642
System Service	-	-	-	-	-
General Plant	86,294	54,629	61,932	59,853	55,100
TOTAL EXPENDITURE	5,358,355	8,575,803	5,444,856	6,196,546	8,708,176

All proposed capital projects are assessed within the framework of its capital budget priority and are outlined in Exhibit 2.

The 2013 Board-approved net capital expenditures were $7,974,605 for the 2013 Test Year. The change in capital expenditures to the 2018 Test Year is a reduction of ($2,616,250.00) or (-32.80%).

PUC Distribution is not requesting any costs for renewable energy connections/expansions, smart grid, and regional planning initiatives. There are no applications in hand and PUC Distribution is not currently aware of any customers wishing to connect renewable generation plant to the grid.

2.1.5.5 Operations, Maintenance and Administration Expense

PUC Distribution is proposing recovery through distribution rates of $11,955,834 in Operating, Maintenance and Administration ("**OM&A**") costs for the 2018 Test Year. The 2013 Board Approved OM&A was $9,952,946 (CGAAP), accordingly the 2018 represents an increase of $2,002,887 or 20.12% increase over the 2013 Board-approved expenditures, or an annual average increase of 4.02%. The inflation rate assumed for labour is 2% and 0% for non-labour. PUC Distribution recognizes that the Input Price Index ("IPI") effective for a rate application in 2018 is 1.2%. However PUC Distribution has reduced the non-labour inflation rate to 0% for budgeting purposes, to account for the expected operating efficiencies which will be achieved in 2018.

The 2013 Board Approved total compensation was $8,095,064, accordingly the 2018 Test Year request of $9,703,257 represents an increase of $1,608,193 or 19.87% (average annual increase of 3.97%).

PUC Distribution's actual 2013 OM&A expenditures were $11.2 million compared to the approved amount in rates of $9.95 million. These costs were necessary for PUC Distribution to safely operate and maintain the distribution system and to meet all incremental regulatory requirements.

The components of the $1.21 million increase are broken out in Table 1-10 below. For comparison purposes the 2012 expenses have been reduced by the regulatory smart meter entry that pertains to prior year costs. Also, for comparison purposes, the 2013 expenses have been reduced by the increased amount ($1,141,376) included in miscellaneous revenue which offsets the new shared corporate headquarter cost.

Table 1-10 – Breakdown of OM&A Increase, 2013 Board Approved to 2013 Actuals.

Area	Amount	
Labour	$444,000	Line and Engineering Dept. labour for capital

		projects was high in 2012 which required the delay in operating and maintenance programs that were resumed in 2013 (Line $298k, Engineering $88k), Meter Dept. labour was temporarily redirected to the smart meter project in 2012 but resumed regular operating and maintenance programs in 2013 ($72k)
Management Labour	$248,000	Engineering P&C Engineer not filled for full year in 2012 but was filled in 2013, higher level of capital effort by management staff in various departments to implement smart meters and TOU billing
Line clearing	$188,000	2012 was a low year for line clearing costs – was highly dependent on area to be cleared and number of contractors bidding – line clearing areas were revised in 2016 to a more consistent annual area and program moved from 3 years to 4 years
Bad Debts	$74,000	Increased cost of energy to customers has increased the amount of customer's bills – number of write-offs (w/o) and amounts per w/o are higher
New Building Operating expenses	$244,000	New building occupied in 2013 – resulted in higher property taxes

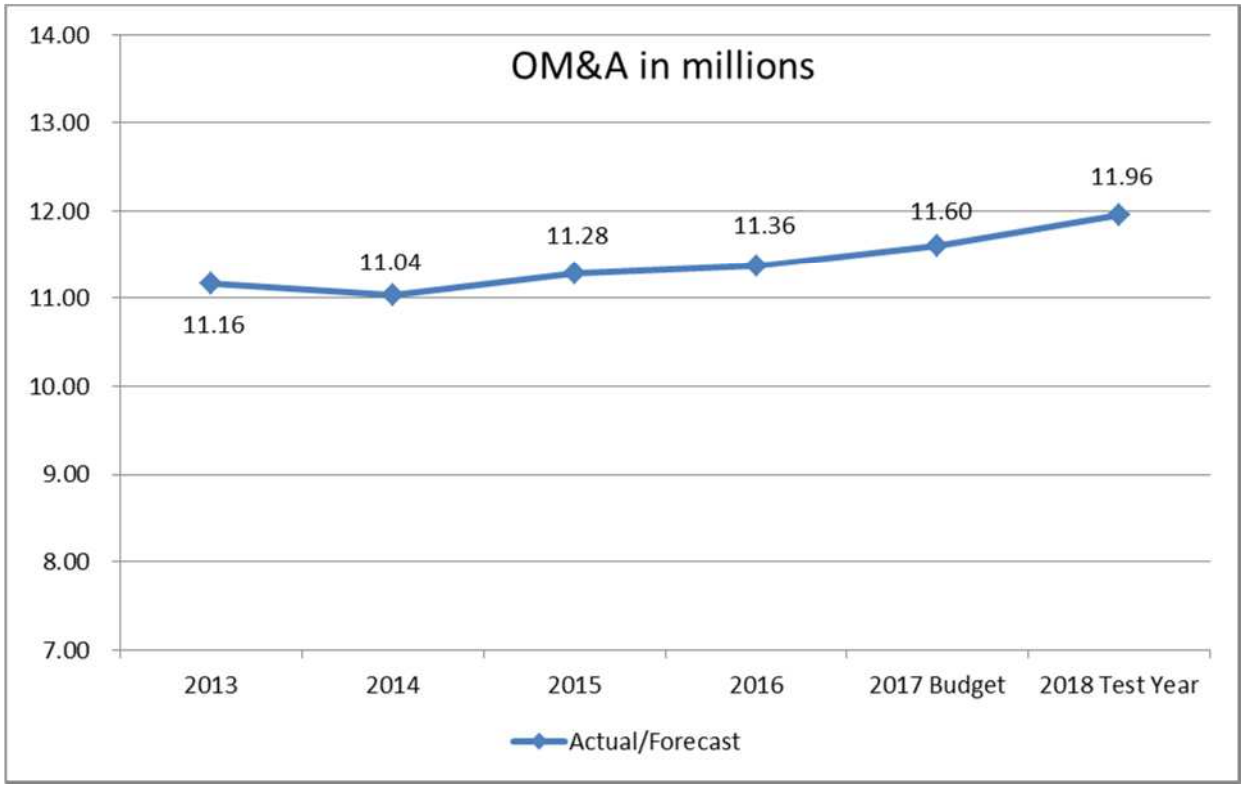
– property taxes		
New Building Operating expenses – other operating expenses	$117,000	New building occupied in 2013 – resulted in higher operating costs – utilities, janitor, etc.
Misc.	($105,000)	Various non-material changes
	$1,210,000	

PUC Distribution is requesting the following items in its Cost of Service rate application which are not currently in expenses being recovered in rates:

- Increased cost for the mandated PCB transformer testing;
- Increased cost for the mandated MIST meter conversion;
- Additional staff resources to address the increased and still increasing regulatory burden, and
- Additional costs for the Distribution/Transmission station maintenance/inspection program.

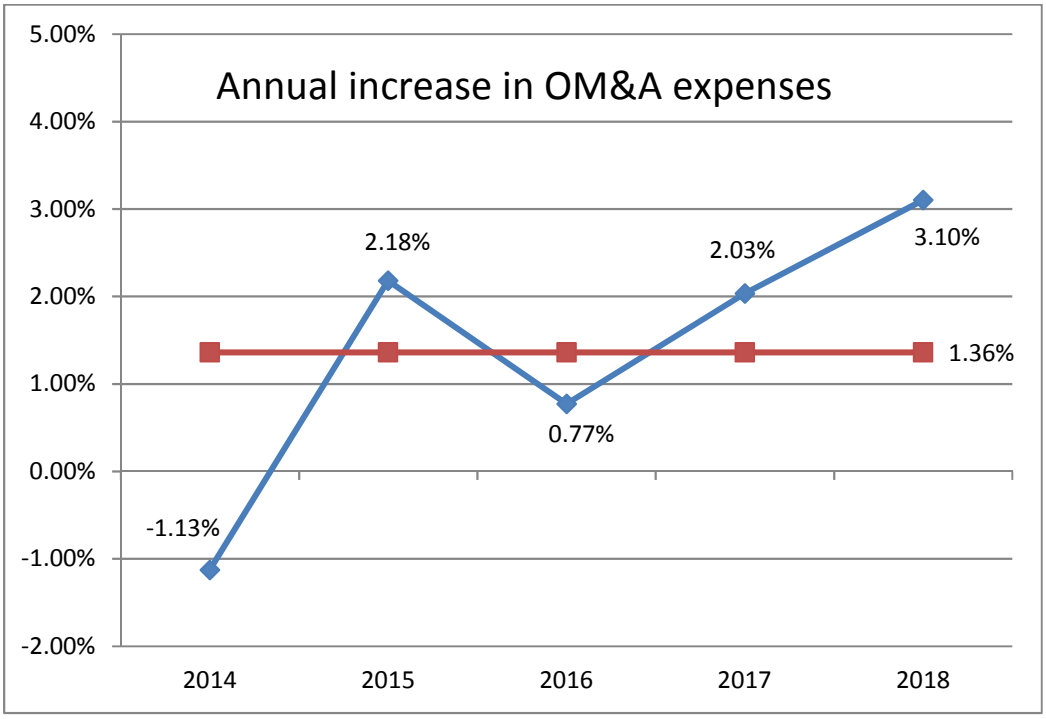
OM&A expenses have increased from $11.02 million in 2013 to $11.96 million in the 2018 test year request for this Application. This equates to an average annual increase of 1.6%. Despite regulatory pressures, the average annual increase over the 2013 to 2018 period has been below the rate of inflation. Figure 3 below illustrates the increase in OM & A over time.

Figure 3 - 2013-2018 OM&A in Millions



The year over year percentage increases are indicated in Figure 4 below.

Figure 4 – Annual Increase in OM&A expenses



2.1.5.6 Cost of Capital

PUC Distribution has used the Board's Cost of Capital Parameter Updates for Rates Effective in 2018 released November 23, 2017 and there are no deviations from the Board's cost of capital methodology in this Application.

2.1.5.7 Cost Allocation and Rate Design

PUC Distribution has not deviated from the Board's cost allocation and rate design methodology.

Cost Allocation

The data used in the updated 2018 cost allocation study is consistent with PUC Distribution's cost data that supports the proposed 2018 revenue requirement outlined in this Application. 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 PUC Distribution from its engineering records, and its customer and financial information systems.

As shown in Table 1-11 below, the resulting 2018 cost allocation study indicates the revenue to cost ratios for Street Lights and Unmetered Scattered Load are outside the Board's range. For 2018, it is proposed the ratio for Street Lights and Unmetered Scattered Load be set at 120% The Residential class will be adjusted upward to maintain revenue neutrality.

Table 1-11 - Revenue to Cost Ratios

Rate Class	2018 Updated Cost Allocation Study	2018 Proposed Ratios	2019 & 2020 Proposed Ratios	Board Targets Min to Max	
Residential	89.8%	92.0%	92.0%	85.0%	115.0%
General Service < 50 kW	117.1%	117.1%	117.1%	80.0%	120.0%
General Service ≥ 50 to 4999 kW	112.5%	112.5%	112.5%	80.0%	120.0%
Street Lights	273.8%	120.0%	120.0%	80.0%	120.0%
Sentinel Lights	95.2%	95.2%	95.2%	80.0%	120.0%
Unmetered Scattered Load	123.8%	120.0%	120.0%	80.0%	120.0%

Rate Design

Except for the Residential class, PUC Distribution proposes to maintain the fixed/variable proportions assumed in the current rates to design the proposed monthly service charges.

On April 2, 2015, the OEB released its Board Policy: A New Distribution Rate Design for Residential Electricity Customers (EB-2012-0410), which stated that electricity distributors will transition to a fully fixed monthly distribution service charge for residential customers. Typically, this transition would be implemented over a period of four years, beginning in 2016. However, in the case of PUC Distribution, the implementation period has been extended to five

years in order to address mitigation expectations outlined in a letter from the OEB published on July 16, 2015. In 2016 PUC Distribution implemented the first year movement of this policy. With a five year implementation, the last year of transition will be 2020.

Table 1-12 below outlines a comparison between the 2017 current and the 2018 proposed distribution rates.

Table 1-12 Distribution Charges

	Monthly Service Charge				Distribution Volumetric Charge incl Transformer Allowance		
Rate Class	2017 Current	2018 Proposed	% Difference	Unit of Measure	2017 Current	2018 Proposed	% Difference
Residential	$16.79	$24.87	48.1%	kWh	$0.0104	$0.0088	(15.7%)
General Service < 50 kW	$17.11	$21.04	23.0%	kWh	$0.0205	$0.0252	23.0%
General Service ≥ 50 to 4999 kW	$114.46	$140.76	23.0%	kW	$5.4372	$6.6563	22.4%
Street Lights	$2.94	$1.42	(51.6%)	kW	$19.1736	$9.2724	(51.6%)
Sentinel Lights	$2.93	$3.60	23.0%	kW	$27.3551	$33.6416	23.0%
Unmetered Scattered Load	$12.69	$15.06	18.7%	kWh	$0.0310	$0.0368	18.7%
Transformer Discount				kW	($0.60)	($0.60)	0.0%

2.1.5.8 Deferral and Variance Accounts

As outlined in Exhibit 9, PUC Distribution is requesting approval for the disposition of Group 1, Group 2 and Other Accounts in the amount of $2,642,670 owed to the customers. This includes Group 1 Accounts excluding account 1589 of $3,175,899 owed to customer and an amount of $118,353 being owed to PUC Distribution by Non RPP customers only for account 1589 -

RSVA - Global Adjustment. It also includes Group 2 accounts of $64,553 owed to customers and other account amounts of $479,430 owed to PUC Distribution by all customers. Other accounts include LRAM Variance Account (1568) and Smart Meter Capital and Recovery Offset Variance - Sub-Account – Recoveries (1555). PUC Distribution proposes a one year disposition period for the Deferral and Variance Accounts. PUC Distribution is not requesting any New Deferral and Variance Accounts.

2.1.5.9 Bill Impacts

PUC Distribution submits that the bill impacts of its proposed electricity distribution rates are reasonable and do not require rate mitigation. The total bill impacts for a PUC Distribution Residential RPP customer at the 10th consumption percentile is 10.35%. This impact which is slightly above the standard acceptable impact of 10% mainly results from a change in the cost allocation model for the Street Lighting class. The current cost allocation model allocates fewer costs to the Street Lighting class than was done in the previous cost allocation study. This results from the issuance of new cost allocation policy for the Street Lighting class by the OEB on June 12, 2015. In order to maintain revenue neutrality the reduced Street Lighting cost are being assigned to the Residential class resulting in the total bill shown below. Since PUC Distribution has extended the implementation to a fully fixed Residential monthly service charge from four to five years it is PUC Distribution position that a further extension would not be reasonable to address an issue that is mainly caused by a revised cost allocation methodology. See section 2.1.3.5 for the Total Bill Impacts table.

Incorporated in the overall monthly bill impact is the effect of the following major components of the electricity bill:

- Distribution rates (monthly service charge and volumetric rates);
- Disposition of deferral and variance accounts:
- Revised Retail Transmission rates;

- Regulatory Charges; and
- Loss Factors.

2.1.6 RRFE Outcomes

2.1.6.1 Customer Engagement – Customer Focus

As of the date of filing this Application, no letters of comment have been received. PUC Distribution will file all responses to matters raised in letters of comment filed with the Board during the course of the proceeding in this Exhibit 1, in accordance with Section 2.4.9 of the Filing Requirement. Appendix 2-AC has been attached to this Exhibit as Appendix 10.

PUC Distribution informed its customers of the proposals being considered for inclusion in the Application through formal and informal customer engagement. The formal customer engagement was accomplished through the use of customer surveys, which gauged customers' understanding of their electricity bill, the electrical distribution system, PUC Distribution operations, and solicited feedback on public perception and customer satisfaction. A customer engagement survey was performed as part of the Application, included at Appendix 11, along with a summary of other customer engagement initiatives ("Customer Engagement Survey").The customer engagement survey was developed to inform customers of the proposed rate increase associated with the Application. It provided a short overview of PUC Distribution's operations, cost drivers, bill breakdown, and a variety of capital projects needed to be completed. It allowed customers to comment, and open two-way communication between PUC Distribution and its customer base, in order to move forward with efficient customer engagement strategies. There were 2,004 participants and 1,321 completed surveys. The survey included informational videos explaining pertinent information related to the Application, such as the cost drivers associated with operations, and planned capital projects.

Another set of surveys was run in 2015 and 2017 by Utility Pulse Division Simul Corporation. These surveys were intended to gauge customer satisfaction, the utility's performance, and the

perception of the utility. Surveys were performed in 2015 and 2017, although all results noted are from the 2017 data ("Utility Pulse Survey").

PUC Distribution engaged customers through a survey for their Strategic Direction Plan in 2016. The survey asked respondents for their opinions on the organization's strategic direction, and what they believed were key challenges for the utility. The survey was initiated by PUC Distribution through Ironside Consulting Services Inc. and there were 194 respondents ("Strategic Direction Plan Survey").

In 2015 and 2016 PUC Distribution participated in a public electrical safety awareness survey to provide a benchmark level concerning the public's electrical safety awareness and identify opportunities where additional education and outreach may be required. The survey gauged the public's awareness level of key electrical safety concepts related to distribution assets ("Public Awareness Safety Survey")

Other formal customer engagement was achieved through a series of information sessions and presentations.

Other Customer Engagement

A free information session was held at the Sault Ste Marie public library in April 2017 in order to respond to customer comments received about bills being too high, and requests to help with lowering utility costs. The workshop was divided into two parts; the first part focused on breaking down an average PUC Distribution bill and explaining how the charges are set. The second part of the workshop provided customers information and ideas to control their energy usage, which included Save on Energy tips and tools. There were about 40 attendees, and both the Communications and Conservations teams from PUC Distribution were on-site to respond to questions from customers ("Public Library Session").

PUC Distribution participated in a series of Community Energy Learning Series Presentations in February 2017. These presentations were intended to address customer concerns regarding the need to lower bills, understand bill charges, and understand the electricity industry overall. The

presentations focussed on understanding the components of the cost of electricity, and methods to use less energy and save money. The presentation series was initiated by the Sault Ste. Marie Innovation Centre in partnership with PUC Distribution, and there were approximately 15 attendees.

PUC Distribution held customers consultations in a series of neighbourhood project meetings in 2017. The consultations took place in neighbourhoods affected by system renewal projects. PUC Distribution's objective was to inform and engage with customers through individual consultations before work began. PUC Distribution spoke to about 20 customers regarding rear-lot pole replacement and underground conversion for pad-mount equipment location placement ("Neighbourhood Project").

Focus groups were conducted by PUC Distribution in partnership with Customer First, a group of LDCs, to promote Home Energy Assessment and Retrofit ("HEAR"), a CDM pilot program. There were two focus groups, the first of which addressed the number of homes in Northern Ontario that utilized electric heat, the second of which helped to improve marketing communications for residential and business customers. There were 16 respondents, ("Focus Groups").

Informal Customer Engagement

Informal customer engagement included industry events, community event partnerships and awareness programs. Some of these events include Bush Plane Days festival, Rotary Fest Summer Festival, Retail Product Consultation Campaigns, and Home and Trade Shows. At these events, PUC Distributions has a presence with informational materials, and also have staff onsite to answer questions from customers. For a full list of events please refer to the Customer Engagement Summary at Appendix 11. PUC Distribution also participates in several charitable initiatives and event sponsorships including the Sault Ste. Marie Downtown Association, Community Tree Lighting and Santa Claus Parade. For a full list of charitable initiatives please refer to the Customer Engagement Summary at Appendix 11. PUC Distribution is focussed on improving its customer engagement through various communication initiatives including having

a full time employee dedicated to communications and community engagement, responding quickly to information requests during power outages, creating a vulnerable person's registry, and communicating through website and social media. PUC Distribution used bill inserts, and media interviews/press releases to provide information to customers about changes that could affect their bill, as well as information about bills, projects, consumption rates, operations, regulation/legislation changes, and current energy industry events. PUC Distribution advertised through print, online, radio and television to promote the community brand, and to build awareness with conservation tips. The bill inserts provided information around legislation, regulations, the Atlas program, service changes, and conservation program initiatives. This method provides a direct line of communication to the customer, and allows for hard copy records of communications to be readily archived. For a full list of communication initiatives, please refer to the Customer Engagement Summary at Appendix 11. PUC Distribution has implemented a Customer Care department with a greater focus on caring for the customer as opposed to just serving the customer. The top 3 customer issues PUC Distribution receives are; high bills, billing inquiries and moving of services. The main themes from the formal and informal customer engagement were the following. For a complete list of programs offered by the Customer Care Department please refer to the Customer Engagement Summary at Appendix 11.

Themes Arising from Formal and Informal Customer Engagement

- Price – 58% of respondents selected; "Keep rates as low as practical while maintaining good quality electrical service" as their number one priority (p.6 Customer Engagement Summary at Appendix 11).

- Reliability – 34% of respondents selected; "Maintaining reliable electrical service (e.g. prevent/reduce power outages)" (p.6, Customer Engagement Summary at Appendix 11). 52% were willing to pay something to improve reliability, and 48% were unwilling to pay any additional amount for an increase in reliability (p.8 Customer Engagement Summary at Appendix 11).

- Customer experience – *Customer Engagement Survey* – Customers' preferred method of contacting PUC Distribution for service issues is by phone (p.6 Customer Engagement Summary at Appendix 11). *Utility Pulse Survey* – Most customers are unaware of aging of distribution system, operational costs, asset renewal (p.13 Customer Engagement Summary at Appendix 11). 72% of all respondents agree PUC Distribution effectively provides information about outages; 75% of all respondents agree PUC Distribution provides information to help customers reduce their costs; 53% of all respondents agree that it was important to review their bill online; 44% of all respondents agree that tools and calculators are important to help manage consumption; 34% of all respondents agree automated alerts to remind one of one's bill date (p.13 Customer Engagement Summary at Appendix 11). *Strategic Direction Survey* – Customers wanted online services for moving of service, more incentive programs to get rid of old appliances, more conservation awareness (p.17 Customer Engagement Summary at Appendix 11).

Effect on Application

As a result of the feedback on price, the DSP was revised several times to ensure that the rate increases were minimized, while considering the Asset Management Plan for necessary system renewal projects in order to maintain reliability. As a result of the feedback on price, PUC Distribution has strictly managed any increases to its OM&A budget in the test year. PUC Distribution has done this by implementing operational efficiency initiatives detailed in section 2.1.6.2 below. In addition, PUC Distribution's OM&A forecast for the test year have embedded operational efficiencies included as further described in Exhibit 4. While PUC Distribution recognizes that the Input Price Index inflation rate is 1.2%, PUC Distribution has reduced the non-labour inflation rate to 0% in 2018. PUC Distribution expects that any inflation gains will be offset by reductions in costs achieved through operating efficiencies.

Despite the fact that a large percentage of PUC Distribution's assets are part of an aging electrical distribution system, PUC Distribution has held off on capital investments for large-scale infrastructure such as the transformer stations, based on customer concern for increasing costs. PUC Distribution has designed its DSP to ensure that asset renewal proceeds at a gradual,

steady pace rather than by sudden or significant increases. The DSP focuses on equipment in poor or very poor condition, or near the end of its service life, in alignment with the Asset Management Plan. The projects included in the DSP are driven in part by safety. For example, one of these projects is the rebuild of a substation (16), in very poor condition, and at the end of its service life. Due to the state of the existing station infrastructure, the switchgear is deemed to be unsafe to operate while energized and must be isolated and de-energized prior to operation. This results in isolation out on the 34.5kV sub-transmission lines, the path for one of two circuits feeding the local hospital.

PUC Distribution has worked to balance the infrastructure and affordability drivers with a proposed rate increase that will affect the total average (using 750kWh) residential electricity bill, by less than $2.00/month.

In response to customers' desire for more information on OM&A cost drivers, PUC Distribution plans to host information sessions, release the survey results, address comments received, and provide clarification about operations.

2.1.6.2 Operational Effectiveness

As stated above and included in PUC Distribution's mission and vision are references to "cost effective", "efficient", "progressive" and "innovation". With that in mind, PUC Distribution continuously works towards improving its performance, reducing costs and being more efficient. The savings achieved since 2013 have contributed to maintaining annual expense increases below inflation. Table 1-13 below quantifies the efficiencies, followed by descriptions of the initiatives which align with the RRFE.

Table 1-13 Quantification of Efficiencies

Efficiency	Estimated Annual Savings
Interactive Voice Response (IVR) System	$ 101,300
Automated Vehicle Locator (AVL)	$ 38,200
Mobile Work Orders (MCare)	$ 44,800
Office in the Truck	$ 54,300
Time of Use Data Usage	$ 24,100
Ontario One Call	$ 35,200
Customer Connect	$ 3,800
Server Virtualization	$ 285,600
Benefit Savings	$ 63,500
Shared Services (labour savings only)	$ 510,000
Vegetation Control Program	$ 75,000
Staffing Changes	$ 415,200
Train the Trainer Programs	$ 7,200
Shared Training	$ 8,000
Busines Improvement Committee	$ 20,000
North Eastern Distributors Buying Consortium	$ 47,400
Total	**$ 1,733,600**

1. Interactive Voice Response (IVR) system

The IVR system allows recorded notifications to be sent to specified groups of customers. The IVR is used in the collection of accounts in place of sending a field service rep to a service address and has resulted in reduced collection charges to customers that are already experiencing difficulties paying their bills. It is also used to notify specific customers in advance of planned outages. Upgraded Telephone System – PUC Distribution's telephone system was upgraded to be capable of providing a standard message to customers in the event of an outage. During a widespread outage, the volume of calls made it impossible to respond to customers and provide information on the outage. The new system provides a message to in-calling customers regarding the area of the outage and indicating that PUC Distribution is aware of the outage. The automated system allows staff to focus on restoring power which results in reduced outage time.

2. Automated Vehicle Locator (AVL)

PUC Distribution implemented an AVL system; a GIS tracking system used primarily to provide the location of company vehicles. The system is used to dispatch the nearest available vehicle in the event of a customer request or emergency. In addition, the AVL system is a valuable piece of PUC Distribution's Lone Worker Program and is used as a tool to determine fuel tax rebates.

3. Mobile Work Orders (MCare)

The mobile work order system is currently being used by the meter department. Upon receiving a customer request, an electronic service order is initiated by the customer care department. The electronic order is dispatched to a field service representative's (FSR) tablet out in the field. The FSR completes the order and updates the status of the order in real time. Paper orders are no longer used in the meter department increasing accuracy, eliminating duplicate work and data errors and reducing paper use and scanning. Efficiency is improved for Customer Care staff due to the ability to check the status of an order electronically which allows quicker response to customer enquiries.

4. Productivity Study

The Productivity Improvement Project commenced in 2014 and was led by the consulting firm Focused Management Resources (FMR). The study's main focus was to improve scheduling and tracking of electrical work.

Areas of development and implementation included, work scheduling, improved transformer tracking, creating protocols for use of the enterprise software in Engineering, procedure changes in Metering, improved material handling, recording and reporting in Stores, and the locate process was simplified in Line Operations. Efficiencies gained include the elimination of the Dispatcher position and other efficiencies discussed in this section.

5. Office in the Truck

This project was launched in the spring of 2015 and was designed to electronically connect employees in the field to the office. The implementation has improved communication (photos,

videos, text, and email). Remote connectivity assists in trouble-shooting in the field using internet, electronic SOPs, etc. This has reduced calls back to supervisors and trips back to the office from the field. The introduction of electronic forms and books has reduced paper handling, the time and cost of printing books (USF standards, electric system feeder books). Field access to the GIS system has proven to be beneficial.

6. Time of Use Data Usage

Time of use data, through the Metersense program is being utilized to proactively respond to outages. Prior to the use of the smart meter data, notification of outages was initiated by customers. By using the smart meter data, crews can be dispatched quicker and the area of outage can be more readily ascertained. A report has also been created that provides minimum, maximum and average voltage levels by customer. The data has been used to identify beneficial locations to install voltage regulators which have improved a customer's power quality.

7. Ontario One Call

Over the historical period, locate request volumes have increased greatly due in part to the exposure brought about by legislation and the ease with which locates can now be requested. As a result, PUC Distribution has had to revise its processes to manage this increased workload, including, purchasing software and hardware and integration of other business systems. The efficiencies gained have resulted in less overtime than would have been the case without the revised processes.

8. Customer Connect

Enhanced web based self-serve options which lead to reduced customer enquiries arising through walk in traffic or phone calls. Self-serve options include balance and billing history, TOU consumption trending, e-billing options. Planned future enhancements include bill payment options, online chat portal, online service agreements and service requests.

9. Server virtualization

PUC Distribution has restructured our server configuration by using virtualization to reduce hardware required. Virtualization provides the ability to run multiple applications and operating systems independently on a single server. This is completed by introducing a layer over the physical server. This layer partitions the server into separate areas that the virtual servers then run on. By implementing server virtualization, hardware can be added dynamically, there are reductions in operations costs, over-provisioning is avoided and one can consolidate hardware.

10. Benefit savings

Periodically PUC Distribution markets the provision of its employee benefit package and on an annual basis negotiates with the current provider to obtain the lowest rates possible. Over the last two years, PUC Distribution has been able to reduce its benefit costs through the negotiation process while maintaining the employee benefits as outlined in its collective agreements.

11. Shared services

PUC Services Inc. provides billing, collection, customer service, and administration services to the affiliated group (including PUC Distribution) and the Public Utilities Commission. Administrative services include payroll, human resources, accounting, IT services, etc. These services are allocated at cost to the various companies based on cost drivers as described in Exhibit 4. The savings from the synergies of the shared services model are passed on to customers. The synergies are in the areas of: shared billing software, shared accounting software, shared hardware configuration, shared Safety program, shared customer service staff, shared communication staff, shared accounting staff (i.e. one payroll clerk, one accounts payable clerk, etc.), shared executive team, etc.

PUC Services also provides billing and customer care services to Espanola Regional Hydro Distribution Corporation. PUC Services has been able to reduce costs to PUC Distribution as a result of leveraging existing staff and billing and customer care software to perform services for both PUC Distribution and Espanola.

12. Vegetation Control Program

PUC Distribution's service territory was divided into 3 sections in order to delineate the areas for the purpose of maintaining safe clearance of trees and branches from distribution system lines and equipment. Vegetation growth around distribution system lines was managed according to our Utility Vegetation Management program on a 3-year cycle by attending to each section in succession on a yearly basis.

The sections addressed in each of the 3 years were unbalanced and led to fluctuations in the vegetation control costs per year. A review of the program was untaken in 2016 and commencing in 2017 the sections to be addressed annually were realigned into 4 sections of similar sizes. The realignment has resulted in reduced annual costs (cycle spread over 4 years) and more consistent costs from year to year (other than potential tending variations).

13. Staffing changes

As noted above, PUC Distribution has pursued and continues to investigate areas where efficiency gains can be realized and passed on to customers. These gains include improving processes in order to optimize staffing levels and ensuring appropriate resources are in the right areas given the changing focus in the electric distribution industry.

Since its last cost of service rate application the following reductions have been made to staffing levels. The changes have been accomplished through streamlining and reassignment of duties.

Dispatcher -.5

Billing Supervisor -.5

Safety Director -.5

P&M labourer -.5

Power Line Technicians -2

Director of Safety and Maintenance -.5

Funding for Interns – communication/HR

These reductions have been partially offset by retirement transition costs and increased program needs in the regulatory (+1 FTE) and station electrician (+1 FTE)

14. Train the trainer program

Three Power line technicians (PLT) completed the "Train the Trainer" program for Utility Work Protection Code training. The three then trained the remainder of the PLTs saving the outside costs for the three training sessions that would otherwise have been required. In a similar manner, two PLTs were trained to deliver confined space training to other staff that required the training.

15. Shared training

Over the years PUC Distribution has engaged other organizations to share the costs of training for common needs. The amount of shared trainings and savings varies from year to year depending on needs. Examples of Shared Training include Fleet Maintenance training three times a year with the Sault Ste. Marie City Board of Work and Fire Services for upgrading diagnostics skills and Leadership and Accountability training which was shared with the City of Sault Ste. Marie.

16. North Eastern Distributors Buying Consortium (NEDBC)

For fourteen years, PUC Distribution has been a member of the Northern Ontario purchasing consortium. In addition to PUC Distribution, the group of seven LDCs includes North Bay Hydro, Greater Sudbury Hydro, Chapeau Public Utilities Corporation, Northern Ontario Wires, Espanola Regional Hydro Distribution Corporation and Algoma Power. Benefits of the group include bulk purchasing discounts as a result of the consortium representing a customer base in the top ten in the province. Saved time due to the shared preparation of major tenders for electrical equipment is also a benefit. Shared purchases include transformers, poles, wire, hardware, switches, insulators, PCB piping and rubber goods.

17. Business Improvement Committee

PUC Distribution is committed to improving business efficiencies and practices. A Business Improvement Committee was established in late 2016 to assist with identifying and analyzing opportunities for improvement. The Committee will work collaboratively to review and consider suggestions for improvement that go beyond any one department's jurisdiction in order to develop recommendations for consideration that are intended to improve the performance of PUC Distribution. The Committee consists of 8 members from across the organization, four of which are from management and four from the union.

The purpose of the Committee as outlined in its terms of reference is to establish a systematic and collaborative approach to identify opportunities for continuous improvement that will result in enhanced operations, more efficient workflow and overall business efficiency. The areas of focus will be operational efficiencies, improved customer service, cost savings or improved productivity, and new business opportunities.

Although the Committee is fairly early in its evolvement, it considered 15 employee suggestions in 2016 and 21 in 2017. Suggestions implemented to date have resulted in approximate annual savings of $20,000 to the LDC. In addition, the Committee continues to model the desired culture of union and management staff working in collaboration and provides a conduit for staff engagement in the identification and analyzing of opportunities for business improvement.

2.1.6.3 Public Policy Responsiveness

In addition to the three Public Policy Responsiveness metrics in the Scorecard, PUC Distribution has successfully and on a timely basis complied with the following changes in law, regulation, policies or guidelines that have affected its business. The changes listed below have added a level of complexity and cost to the operation of PUC Distribution.

1. Smart meter deployment

The Ministry of Energy mandated that smart meters be installed for all customers in the province of Ontario. PUC Distribution met the mandated installation date by installing 29,385 residential and 3,239 general service < 50 kW smart meters by October 31, 2011 which represents the entire population of mandated smart meters.

2. Time of Use (TOU) Pricing

In mid-2009, the Ontario Government articulated an expectation that 1 million RPP consumers would be billed using TOU pricing by the summer of 2010, rising to 3.6 million RPP consumers by June 2011. On June 24, 2010, the Ontario Energy Board issued a proposed determination regarding time-of-use pricing for regulated price plan customers (Board File No. EB-2010-0218), suggesting that distributor-specific TOU dates would be the most appropriate approach, as it allows for the deadline to logically follow MDM/R enrolment activities.

On August 4, 2010 the Ontario Energy Board issued a determination confirming a mandatory TOU date of October 2011 for PUC Distribution. The mandatory TOU date was the earliest month in which TOU billing must commence. PUC Distribution commenced the transition to TOU pricing as of October 2011 and completed the transition to all customers in December 31, 2011. An extension was granted for a small group of customers that were completed in the spring of 2012.

3. Adoption of International Financial Reporting Standards (IFRS)

The Canadian Accounting Standards Board required publicly accountable enterprises to transition from CGAAP to IFRS. PUC Distribution adopted IFRS for financial reporting as of January 1, 2015. IFRS has been adopted for financial reporting and MIFRS for regulatory reporting.

4. Change from GST to HST

The Ontario Government combined the Goods and Services Tax (GST) with the Provincial Sales Tax (PST) on July 1, 2010. PUC Distribution met the implementation date for the bill print and other necessary system changes.

5. Implementation of the Low-income Energy Assistance Program (LEAP)

The Board determined that the funds to be distributed by distributors to LEAP should be the greater of $2,000 or .12% of a distributor's Board-approved distribution revenue requirement. PUC Distribution has funded the LEAP each year in the approximate amount of $20,000.

6. Implementation of the Ontario Clean Energy Benefit (OCEB)

Effective January 1, 2011, a credit of 10% was applied to the base invoice amount of each residential and general services less than 50 kWh bill. PUC Distribution implemented the changes necessary to calculate and include the credit on customers' invoices until it was discontinued as of December 31, 2015.

7. Implementation of Ontario Energy Support Program (OESP)

The OESP program commenced in 2016 to provide "on bill" credits and bill print messaging to low income consumers. Testing was performed in 2016 with the central service provider to integrate into the billing system. Files are transferred through the CoreFTP, a script picks up the files daily and processes it through the billing system, a call is automatically logged on the account in the billing system and a response file is generated and sent back to the Central Service Provider (CSP) to validate the account. If the account is validated the CSP sends a file with a tariff code that is set up in the billing system to specify the time period and dollar amount of the "on bill credit". Tariff levels and credits have changed over the last 2 years which has involved additional testing and integration. The enhanced Ontario Electricity Support Program came into effect May 1, 2017. The enhanced program included a wider range of eligible consumers and tariff codes, increased OESP credits by 50%, and eliminated the OESP kWh charge. Investigation of discrepancies and customer inquiries of the program including bill inserts are additional requirements of the LDC. As a continuing requirement of the OESP program, customer care runs a monthly listing of all customer's that have a OESP credit expiring within 90 days and sends a written letter to the customer reminding them of the credit expiration and the steps required to re-apply.

8. Information on Invoices to Low-Volume Consumers of Electricity

In 2013 line loss presentment on bills prescribed by regulation was to be included in the delivery line of the bill for non-retailer customers. Similar changes to retailer bills was required for July 1, 2015. These changes involved bill print set-up and testing

9. Global Adjustment Bill Print Modifications

In 2015 regulations were issued for the global adjustment bill print to include the usage and rate on the bill. This required billing system testing and bill print programming modifications.

10. Industrial Conservation Initiative (Class A Global Adj)

The Industrial Conservation Initiative (ICI) is a form of demand response that allows participating customers to manage their global adjustment (GA) costs by reducing demand during peak periods. Customers who participate in the ICI, referred to as Class A, pay GA based on their percentage contribution to the top five peak Ontario demand hours (i.e. peak demand factor) over a 12-month base period. A number of eligibility changes have occurred since the initiatives introduction. Changes to eligibility have been made to include consumers in manufacturing and industrial sectors with NAICS codes commencing with the digits “31, “32”, “33” or “1114” and having an average monthly peak demand of greater than 500kW and less than or equal to 1MW. These customers may opt-in to the ICI. Previously, PUC Distribution had no eligible consumers, but with the changes has made system changes to notify customers of their eligibility and accommodate the new customers who have opted-in.

11. Distribution System Code Amendments

A number of changes have been made to rules impacting bill issuance, payment procedures, disconnections for non-payment, arears payment agreements, deposit requirements, rules for low income customers, etc. Several of these changes have necessitated changes billing and collection processes and increased reporting requirements.

12. Revised Electricity Reporting and Record Keeping Requirements

The Board has amended the Electricity RRR to implement an electricity distributor scorecard. PUC Distribution has implemented the scorecard and is in compliance with any changes since the March 2014 notice introducing the scorecard.

13. Accessibility for Ontarians with Disabilities Act, 2005

Effective January 2012, the rules associated with the Act came into effect for all Ontario businesses. PUC Distribution has ensured that material presented on its website is entirely accessible.

14. Employment Standards Act Changes

Effective January 1, 2018, employees who have been employed for longer than one week, are eligible for Personal Emergency Leave (PEL). PUC Distribution has reviewed its leave policies and has made adjustments to comply with the legislation.

15. Ontario One Call

All owners and operators of underground infrastructure are required to be members of ON1Call and to respond to locate requests. PUC Distribution is a member of ON1Call.

16. Customer Engagement

LDCs are expected to consult with consumers in the development of their rate applications. PUC Distribution has listed in this application their customer engagement activities, which include two required customer satisfaction surveys (2015 and 2017) and a customer engagement survey specific to this rate application. The customer satisfaction survey and the customer engagement survey for the rate application are new for PUC Distribution since the previous cost of service rate application.

17. Distribution System Plan (DSP) Requirements

Chapter 5 of the Filing Requirements for Electricity Transmission and Distribution Applications details the requirements of the Distribution System Plan that is to be filed with a Cost of Service Rate application. This is a new requirement for PUC Distribution since its previous cost of service rate application.

18. Public Safety Awareness Survey

In 2014 the Board request that the Electrical Safety Authority (ESA) to recommend an electrical safety measure for the LDC scorecard. ESA recommended and the OEB accepted a standard survey methodology for use as one of three components of a Public Safety scorecard measure for distributors to ensure consistency in practice throughout the industry. LDCs are required to perform a biannual Public Awareness of Electrical Safety Survey. PUC Distribution completed its first survey in 2016 and is due to complete its second in 2018.

19. Ontario Fair Hydro Plan (OFHP) Dynamic Messaging

A specific dynamic calculation of savings associated with the Fair Hydro Plan is to be on each customer's bill by March 31, 2018. The calculation will be based on:

- The difference between RPP prices determined by the OEB in the normal course without taking into the forecast impact of the OFHP, including TOU prices and the global adjustment modifier.
- Delivery line losses associated with the savings with lower electricity prices.
- First Nations Delivery Credit.
- Savings associated with reduction of the OESP charge.
- Savings associated with the reduction of the Rural Rate Protection Charge.
- 8% Rebate savings that was implemented Jan 1, 2017.
- HST savings related to the reduction.

Computing of the OFHP is a complex and challenging calculation for LDC's primarily due to the fact rates before OFHP adjustments are not stored in billing systems. The messaging at the

bottom of the bill will be "Ontario's Fair Hydro Plan saved you $$ on your bill. This includes the 8% Provincial Rebate". This messaging requires lengthy testing and set-ups. In addition, the new rates and set-up will need to be updated at each rate change to properly reflect the savings.

20. Ontario Fair Hydro Plan (OFHP) Bill Messaging

Effective July 1st 2017 messaging on the bill was to change to "Ontario's Fair Hydro Plans substantially lowers electricity bills for a typical residential customer. This includes the eight per cent rebate introduced in January 2017 and builds on previous initiatives to deliver broad-based relief on all electricity bills." Testing and implementation was required.

21. First Nations Delivery Credit

Effective July 1st 2017 residential on-reserve customers receive a 100% delivery charge credit. This includes line losses, delivery, and transmission charges. Testing and programming in the billing system was performed with the use of flat rates and bill print modifications. Additional reporting requirements and account set-ups were required. Customer Care monitors and set-ups the delivery credit for eligible consumers.

13. Retailer Bill Presentment Changes

Effective July 1, 2017 the Retail Settlement Code was amended to mandate bill presentment for retailer enrolled customers to include the website of the retailer on the bill. The change required Customer Information System modifications and programing that required testing and implementation.

14. Written Notice of Switch to Retailer

The Retail Settlement Code was amended to include an OEB approved notice of switch letter to be sent by electricity distributors to remind consumers they have entered into a contract and that their supply arrangements are changing. The letter is to be sent within 5 business days of completion of processing a Service Transaction Request (STR). The requirements to send the notice of switch letter took effect July 1, 2017. PUC Distribution has processes in place to

monitor the STR's and send an order to the Customer Care department to issue a notice of switch letter to the customer.

15. Ontario Rebate to Electricity Customers

Effective January 1, 2017 the Ontario Rebate for Electricity Consumers came in effect that established a framework under which consumers with eligible accounts are entitled to receive an 8% rebate. Additional billing system rate set-ups including the use of flat rates were tested and implemented. Bill print changes and messaging were also required. A separate line item must appear on the bills labelled "8% provincial rebate". The following messaging at the bottom of the bill was required and tested: "The Ontario government is proving a rebate on your electricity costs equal to the provincial portion of HST". Envelopes were re-ordered with the Ontario starburst logo and the wording "Ontario is helping to reduce electricity costs for families, businesses and farms." Additional record keeping and reporting requirement were regulated for the 8% rebate. Quarterly bill inserts were also required and mailed by the LDC.

16. Smart Meter Entity (SME) Additional Reporting and Synchronization

Effective January 1, 2017 the OEB required the SME to collect the following information associated with each meter:

- The postal code
- The distributor rate class
- The commodity rate class
- Occupant change data

Modifications and programming changes were implemented to the Customer Information System including testing, and technical specifications. Testing was performed on data synchronization with the MDM/R to ensure all data required was successfully synced.

17. Debt Retirement Exemption and Bill Presentation

In 2016 residential consumers were exempted from the debt retirement charge. Regulations prescribed the debt retirement line remain on the bill with zero dollar value and a separate line be placed at the bottom of the bill stating "debt retirement charge exemption saved you $". The change required additional set-ups in the billing system, testing and bill print modifications.

18. Metering Inside the Settlement Timeframe (MIST) Meter Requirement

PUC Distribution is required to change out approximately 360 existing non interval meters for customers that are ≥50 to 4999 kW and <500 kW. This new class of interval Mist meter is required to be installed by August 21, 2020. The meter will be another in the line of Smart Meters provided by our existing supplier. These meter replacements will require additional investments as each meter will be approximately a seven hundred dollar expense along with the installation and ongoing operating and administrative costs. The trickledown effect from the introduction of the interval Mist meter and the new class of accounts that will be created will create increased workloads for our Billing and Settlement, Metering, Information Technology, Customer Service and Regulatory departments.

19. Overhead Transformer PCB Testing

Environment and Climate Change Canada has issued PCB Regulations (SOR/2008-273) which came into force on September 5, 2008. Regulation strictly states deadlines as to when specific assets containing PCB's exceeding specific concentration limits must be removed and properly disposed of. Pole-top electrical transformers containing PCB's in a concentration of 50 mg/kg or more are to be removed from service before December 31, 2025. PUC Distribution plans to have the approximate 1,800 transformers tested by the 2022 in order to have replacements completed by 2025.

20. New Independent Electricity System Operator (IESO) Requirements for Under-Frequency Load Shedding Scheme

The Ontario Reliability Compliance Program (ORCP) is used by the IESO to monitor, assess and enforce compliance with reliability standards and criteria in Ontario. As of January 2016,

utilizing the IESO's Reliability Standards Mapping Tool, PUC Distribution has determined that they must be compliant with a total of eleven requirements from three different reliability standards:

PRC-005-2(i)

PRC-006-1

PRC-008-0

The stations maintenance/inspection program is based on a six year cycle for PUC Distribution's 15 distribution stations and a four year cycle for the two transmission stations. In order to accommodate this change in standards, PUC Distribution plans to fill two substation electrician positions.

2.1.7 Performance Management

Performance Evaluation

In this Application, PUC Distribution has presented its performance for each of the Board's performance outcomes over the last five years, its current performance, and its projections for continuous improvements over the term of the Application. The Application discusses how PUC Distribution's self-assessment has informed its Business Plan and the Application.

Renewed Regulatory Framework for Electricity Distributors (RRFE)

The Board introduced a new approach to rate setting at the end of 2012 with the Renewed Regulatory Framework. The Renewed Regulatory Framework is a performance based approach to regulation that focuses on the achievement of outcomes such as efficiency, reliability, sustainability, and financial viability. The Performance Measurement for Electricity Distributors: A Scorecard Approach, Board File EB-2010-0379 was published on March 5, 2014. The report details the scorecard measures approach which the Board expects to use in order to monitor and

assess a distributor's effectiveness and improvements in achieving the four performance outcomes of:

- **Customer Focus**: services are provided in a manner that responds to identified customer preferences;
- **Operational Effectiveness**: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;
- **Public Policy Responsiveness**: utilities deliver on obligations mandated by government (e.g. in legislation and in regulatory requirements imposed further to Ministerial directives to the Board), and
- **Financial Performance**: financial viability is maintained; and savings from operational effectiveness are sustainable.

Scorecard

The Scorecard Approach, issued on March 5, 2014 details the scorecard measures approach which the Board expects to use in order to monitor and assess a distributor's effectiveness and improvement in achieving the four performance outcomes mentioned above, and to facilitate distributor benchmarking. During the implementation period of the scorecard, the Board recognized that new measures may not have uniform definitions and therefore the Board has not yet determined industry targets for these measures. The Board intends for all measures on the scorecard to be uniform and have industry targets by 2018 for comparability and benchmarking purposes.

PUC Distribution has published its most recent scorecard for public viewing on its website at http://www.ssmpuc.com/index.cfm?fuseaction=content&menuid=104&pageid=1090.

PUC Distribution's scorecard for 2016 is presented below and in Appendix 4 in full.

2.1.7.1 RRFE Performance Outcomes

This Section details the steps PUC Distribution has taken in respect of each of the Board's four RRFE outcomes in accordance with benchmarking of electricity distributor cost performance.

A. Customer Focus

i. Service Quality

Table 1-14: Scorecard Performance Category: Service Quality

Measure	2012	2013	2014	2015	2016
New Residential/Small Business Services Connected On Time	95.80%	96.50%	93.00%	97.20%	98.90%
Scheduled Appointments Met On Time	98.40%	97.10%	95.40%	97.40%	98.30%
Telephone Calls Answered On Time	74.60%	80.90%	81.90%	82.30%	81.30%

New Residential/Small Business Connected on Time

As shown in Table 1-14 above, over the last 5 years, PUC Distribution has consistently exceeded the OEB mandated target of at least 90% in connecting new residential or small business customers on time. In the last 3 years (2014-2016), PUC Distribution has connected 213, 144 and 349 eligible low-voltage residential and small business customers respectively with an increasing percentage of on time connections. The improved performance over the last 3 years can be partly attributed to a reduction in capital works projects which allowed additional resources to focus on low volume connections. PUC Distribution has also demonstrated a commitment to continuous improvement through staff education to ensure customer satisfaction is a top priority.

PUC Distribution's target for this metric in 2018 is 90%.

Scheduled Appointments Met On Time

As a result of our emphasis on customer satisfaction, over the last 5 years PUC Distribution has consistently exceeded the OEB mandated target of at least 90% in scheduled appointments met on time. PUC Distribution has scheduled 1,466, 1,240 and 1,468 appointments in 2014, 2015

and 2016 respectively in relation to meter installs and removals, service disconnects and reconnects and meter locates etc. and has yielded an average on time completion percentage within a 4 hour window of 97.32% over the last 5 years.

PUC Distribution's target for this metric in 2018 is 90%.

Telephone Calls Answered on Time

Between 2012 and 2016, PUC Distribution has experienced an average of 39,781 calls from customers per year, which equals approximately 159 calls per working day. In spite of this large call volume, PUC Distribution's Customer Care Department has answered these calls within 30 seconds or less 80.20% of the time. This result significantly exceeds the OEB mandated 65% target for timely call response. However, in 2012, as a result of an increased call volume with a smaller FTE count in the Customer Care Department due to temporary absences, PUC Distribution did not attain the corporate target of 75%. PUC Distribution previously introduced Customer Connect, an on line method for customers to access consumption data and plans in the future to introduce more on line tools such as on line customer sign-up to move more routine requests away from the phones. In addition a process has commenced to review the structure of the customer service and collection functions to provide a more efficient "one-stop" experience for customers. PUC Distribution's target for this metric in 2018 is 75%.

ii. Customer Satisfaction

Table 1-15: Scorecard Performance Category: Customer Satisfaction

Measure	2012	2013	2014	2015	2016
First Contact Resolution			99.89%	99.92%	99.58%
Billing Accuracy			99.83%	99.36%	99.97%
Customer Satisfaction Survey Results			In Progress	79.00%	80.00%

First Contact Resolution ("FCR")

PUC Distribution's First Contact Resolution was measured by tracking the number of electric related calls which were escalated to a Senior Customer Care Representative or

Supervisor/Manager. This was accomplished by creating two specific call types in our Customer Information System (CIS) which would then be queried to provide the number of customer concerns which were escalated. To establish the number of calls which were handled without escalation, the total number of calls which were escalated to a higher level of management was subtracted from the total number of calls received. However, it should be noted that First Contact Resolution can be measured in a variety of ways and further regulatory guidance is necessary in order to achieve meaningful comparable information across electricity distributors. As shown in Table 1-15 above thus far, PUC Distribution has maintained a FCR percentage above the distributor target of 99%, averaging 99.80% since 2014.

PUC Distribution's target for this metric in 2018 is 99%.

Billing Accuracy

PUC Distribution issues approximately 400,000 bills annually and has achieved an average accuracy percentage of 99.72% over the 3 year period of 2014 to 2016. This score compares favourably to the prescribed OEB target of 98%. PUC Distribution continues to monitor its billing accuracy results and processes to identify opportunities for improvement.

PUC Distribution's target for this metric in 2018 is 98%.

Customer Satisfaction Survey

PUC Distribution engaged the UtilityPulse Division of Simul Corporation to conduct our 2015 and 2016 customer satisfaction survey. The survey is attached as Appendix 5. The UtilityPulse Electric Utility Survey is in its 19th year of annual surveys and is used by a significant number of Ontario distributors. For 2015, the final report on our customer satisfaction survey was received in June 2016, and PUC Distribution received a B+ customer satisfaction score of 79% (post survey result). In 2016, the final report on our customer satisfaction survey was received in March 2017, and PUC Distribution received a B+ customer satisfaction score of 80% (post survey result) which is above the Ontario benchmark survey that had a grade of "B". The raw score had a slight increase from our last survey of 79%. The survey asked customers questions

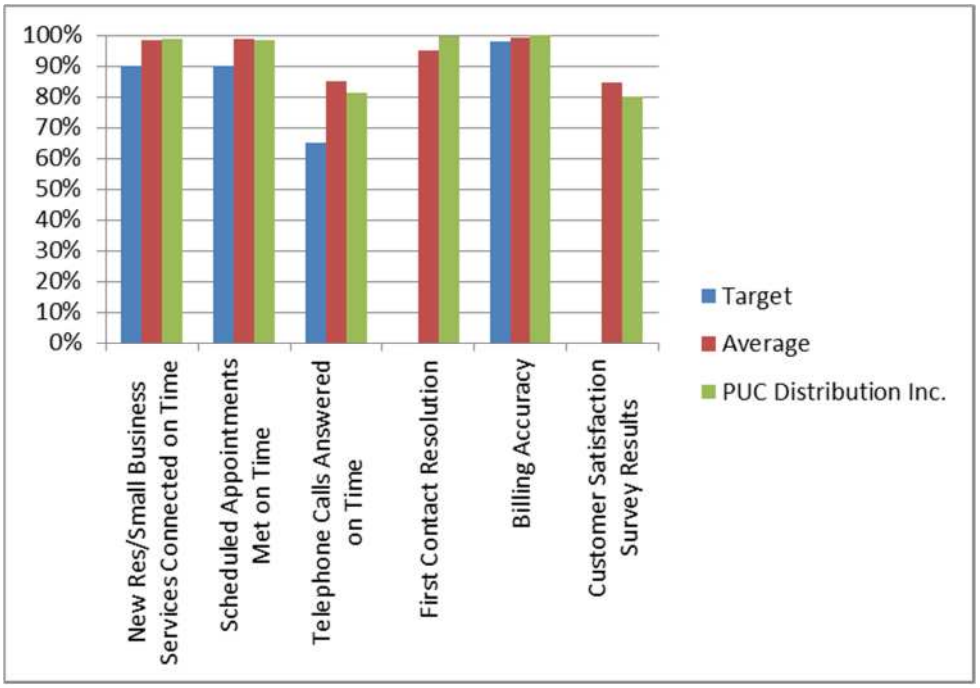
on a broad range of topics, including overall satisfaction with reliability, customer service, outages, billing and corporate image. These customer satisfaction surveys are an important element in our overall customer engagement strategy providing further insight towards planning and supporting customer service improvement at all levels within PUC Distribution.

PUC Distribution's target for this metric in 2019 is "A-" or 85%.

Figure 5 below compares PUC Distribution's 2016 Service Quality and Customer Satisfaction results to the provincial target and the average for all LDCs in the province. Currently there are no provincial targets for First Contact Resolution and Customer Satisfaction Survey.

As indicated, PUC Distribution met all provincial targets in 2016. For the telephone call answered metric, although PUC Distribution exceeds the provincial target, it is slightly below the provincial averages. As noted above PUC Distribution is exploring options to reduce telephone traffic to improve the calls answered metric and provide a more efficient method for customers to interactive with the LDC. Similarly, for the Customer Satisfaction Survey, PUC Distribution is below the provincial average (80% vs the provincial average of 84.8%). Due to the nature of the reporting (ex. numeric score vs letter rating) a provincial average was estimated. PUC Distribution has provided a list of customer engagement initiatives in the Customer Engagement Summary at Appendix 11. Such initiatives will continue in the future, aimed at improving customer satisfaction.

Figure 5 - Provincial Comparison - Customer Focus – Service Quality and Customer Satisfaction



B. Operational Effectiveness

i. Safety

Table 1-16: Scorecard Performance Category - Safety

Measure	2012	2013	2014	2015	2016
Public Safety Awareness				86.00%	86.00%
Regulatory Compliance Ontario *Reg 22/04*	NI	C	C	C	C
Serious Incident Index - # of General Public Incidents	3	1	3	1	0
Serious Incident Index - Rate per 10, 100, 1000 km of line	0.407	0.135	0.405	0.134	0

The public safety measure was introduced by the OEB in 2015 and focuses on Component A - the safety of the distribution system from a customer's point of view. The Electrical Safety Authority ("ESA") provides an assessment as it pertains to Component B – Compliance with Ontario Regulation 22/04 Electrical Distribution Safety ("O.Reg 22/4" or "the Regulation") and Component C – Serious Electrical Incident Index (see Table 1-16 above).

Component A - Public Safety Awareness

A representative sample of PUC Distribution's service territory population was surveyed in late 2015 to gauge the public's awareness level of key electrical safety concepts related to distribution assets. The purpose of the survey was to provide a benchmark level concerning the public's electrical safety awareness, and identify opportunities where additional education and outreach may be required. The results of the survey were analyzed in 2016, a number of opportunities to improve our existing outreach programs were identified and an action plan was developed.

One item of note from the survey results indicated that more emphasis was required to ensure public awareness of Ontario One Call. In an effort to improve this metric, PUC Distribution approved a budget in 2016 (for 2017) to purchase promotional Dig Safe decals for the entire operations fleet, and through participation with the Association of Electrical Utility Professionals ("AEUSP"), has contributed to the production of a series of Electricity Safety videos for television broadcast in our service area. PUC Distribution continues to look for every opportunity to communicate and engage with the public to promote electrical safety awareness in our service area. Below are examples of PUC Distribution's public safety communication initiatives:

- Elementary School Electrical Safety Program for Grade 3 – 5 within our geographic service territory. Participation averages 24 schools annually covering approximately 70 classes, and 1,900 students

- Advanced Research & Technology Innovation Expo ("ARTIE") (approximately 360 students and their teachers participated)

- Sault Ste. Marie Science Festival (approximately 500 adults and children attended)

- Sault Ste. Marie PUC Distribution website – Safety tab with particular activities aimed at educating young people on electrical safety

- Advertisements in the geographic service territory consists of newspaper and radio ads

PUC Distribution's target for this metric is to improve each year the survey is undertaken.

Component B - Regulatory Compliance with Ontario Reg. 22/04

O.Reg 22/04 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, and specifications and the inspection of construction to ensure there are no undue hazards before they are put in service.

Component B is comprised of an External Audit, a Declaration of Compliance, Due Diligence Inspections, Public Safety Concerns, and Compliance Investigations. ESA evaluates all these elements as a whole to determine the status of compliance. In each of the past four years, PUC Distribution was found to be compliant with O.Reg 22/04. PUC Distribution attributes this continued success to our strong commitment to safety, and adherence to company policies and procedures.

PUC Distribution's target for this metric in 2018 is to have zero (0) safety compliance issues.

Component C – Serious Electrical Incident Index

Section 12 of O.Reg 22/04 specifies the requirement to report to ESA any serious electrical incident of which they become aware within 48 hours after the occurrence. In the last 5 years, PUC Distribution has made a large improvement in reducing serious electrical incidents involving the public. In 2012 and 2014, PUC Distribution reported 3 incidents involving the general public.

The incidents referred to in 2012 include:

1. A customer cut a tree onto a power line;
2. A local contractor's delivery truck boom made contact with a power line; and
3. A local contractor's mobile crane made contact with a power line.

The incidents referred to in 2014 include:

1. A customer cut a tree onto a power line;
2. A burnt conductor on the road; and
3. An underground line was contacted by a contractor installing fence posts.

In addition to the public awareness items listed above, in these circumstances described in 2012 and 2014, PUC Distribution representatives met with the person involved to discuss safety issues, obtaining locates, etc. In the specific case of the downed line, PUC Distribution provided a training session with the Sault Ste. Marie Public Board of Works and Police Department.

In the 2016 reporting period, PUC Distribution did not experience any serious electrical incidents.

To increase public safety awareness, PUC Distribution offers electrical safety awareness outreach via; newspapers, radio, public events, presentations to elementary school students, and detailed hazard awareness presentations to contractors.

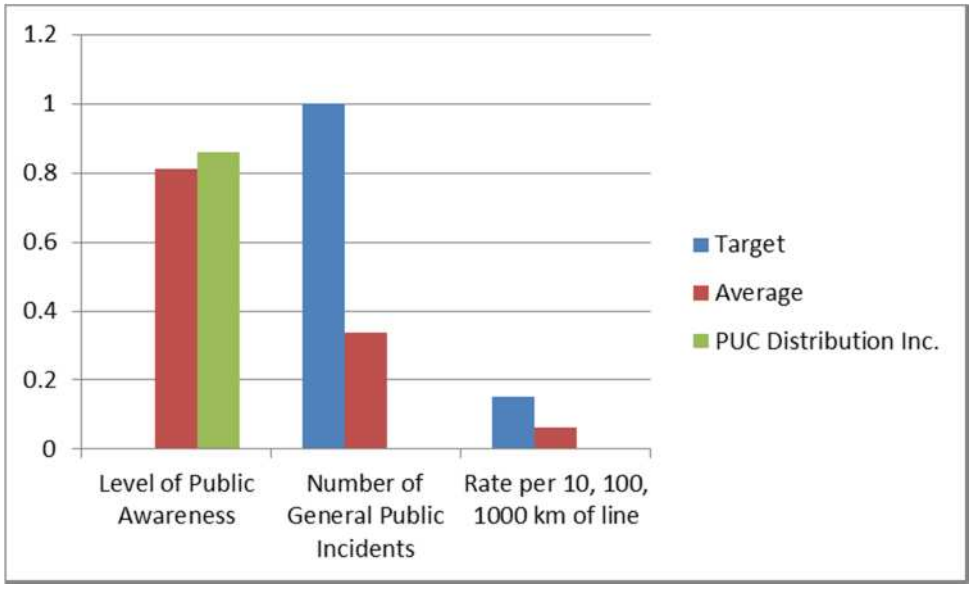
PUC Distribution's target for this metric in 2018 is to have zero (0) serious electrical incidents reported. This is more aggressive than the OEB scorecard target of 1. In PUC Distribution's view, 1 serious electrical incident is 1 too many. Management has its internal target accordingly.

Figure 6 below compares PUC Distribution's 2016 Operational Effectiveness in the safety area to the provincial target and the average for all LDCs in the province. Currently there is no provincial target for Level of Public Awareness. PUC Distribution had no general public incidents in 2016 and therefore the rate per kilometer per line is zero.

As indicated, PUC Distribution exceeded the average level of public awareness and in fact, at 86%, had the highest rating of all provincial LDCs.

PUC Distribution's 2016 Reg. 22/04 audit found that PUC Distribution remains compliant with the regulations.

Figure 6 - PUC Operational Effectiveness in Safety & Provincial Target



ii. System Reliability

Table 1-17: Scorecard Performance Category – System Reliability

Measure	2012	2013	2014	2015	2016
Average Number of Hours that Power to a Customer is Interrupted - SAIDI	1.65	1.42	1.19	1.37	1.49
Average Number of Times that Power to a Customer is Interrupted - SAIFI	2.17	1.78	1.21	1.03	1.41

Table 1-17 above displays the system reliability data from 2012 to 2016. A key change for 2016, as required by the OEB, is the revised reporting of reliability data with respect to Major Events. Specifically the change serves to adjust the reliability data to remove the impact of Major Events. Additionally, distributors are required to report criteria to monitor the distributor's performance related to the Major Event. The 2016 Scorecard system reliability data, excludes both Loss of Supply and Major Events. The adjusted reliability measures capture interruptions caused by circumstances within the distributor's control and are published in the 2016 scorecard. A "Major Event" is defined as an event that is beyond the control of the distributor and is; unforeseeable, unpredictable, unpreventable, or unavoidable. Such events disrupt normal business operations

and occur so infrequently that it would be uneconomical to take them into account when designing and operating the distribution system. Such events cause exceptional and/or extensive damage to assets, take significantly longer than usual to repair, and affect a substantial number of customers. PUC Distribution calculates major event day scope using the IEEE Standard 1366-2003, "IEEE Guide for Electric Power Distribution Reliability Indices".

SAIDI and SAIFI

The average duration of outages is often due to the severity of weather events – System Average Interruption Duration Index ("SAIDI") and the number of times power to a customer is interrupted is often due to accidents, storms, lightning, high wind and defective equipment – System Average Interruption Frequency Index ("SAIFI").

Approximately forty percent of all of PUC Distribution's outages can be attributed to defective equipment. PUC Distribution also experienced large amount of outages caused by adverse weather which typically included high winds (resulting in tree contact), snow storms and rain storms.

PUC Distribution programs in place to address reliability include:

- Use of high quality engineering design standards
- Proactive upgrading of equipment (switches, restricted wire)
- Smart meter data to quickly identify outages
- Preventative maintenance such as infrared scanning and pole testing
- Diligent tree-trimming program

System Average Number of Hours that Power to a Customer is Interrupted (SAIDI)

The System Average Interruption Duration Index ("SAIDI") of 1.49 in 2016 was below the distributor target of 1.86. There are ongoing efforts to improve reliability including replacing aging infrastructure and improving vegetation management.

PUC Distribution's target for SAIDI in 2018 is lower than the OEB distributor target (fixed five year average (2012-2016) of 1.42.

System Average Interruption Frequency Index (SAIFI)

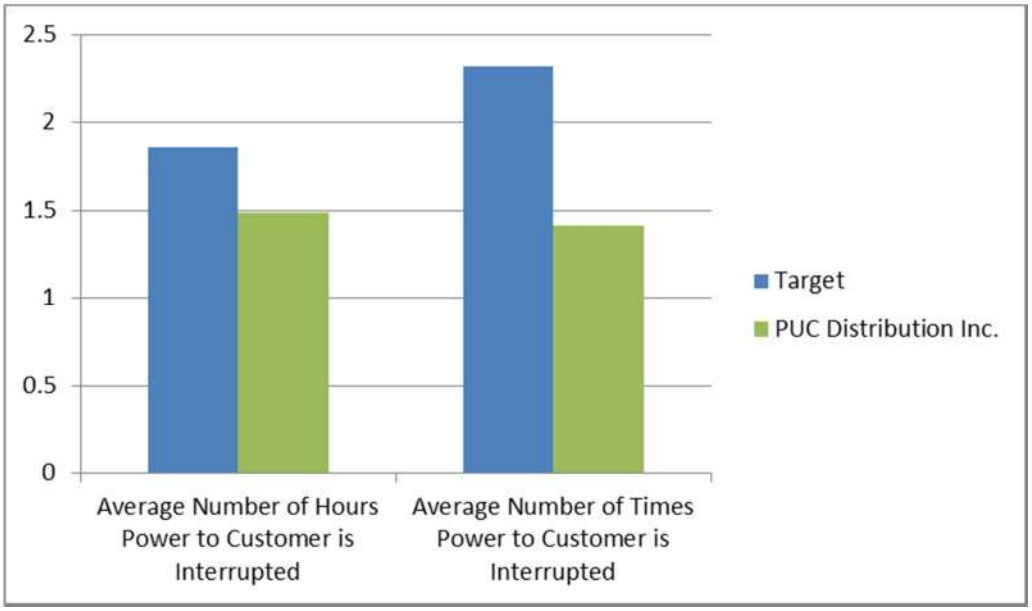
The System Average Interruption Frequency Index ("SAIFI") of 1.41 in 2016 was substantially below the target of 2.32. Consistent with SAIDI, there are ongoing efforts to improve reliability including replacing aging infrastructure and improving vegetation management.

PUC Distribution's target for SAIFI in 2018 is lower than the OEB Distributor target (fixed five year average (2012-2016) of 1.52.

Figure 6 below compares PUC Distribution's 2016 Operational Effectiveness in the system reliability area to its scorecard target.

As indicated, PUC Distribution exceeded its reliability targets in 2016, however were under the provincial averages. Equipment failures have been the predominant cause of outages in the last several years. To improve reliability, all of the investments in the "System Renewal" category of fixed assets are aimed at replacing assets in very poor or poor condition with priority given to renewal of those assets in highest risk of failure with most serious consequences.

Figure 6 - System Reliability & Scorecard Target



iii. Asset Management

Table 1-18: Scorecard Performance Category – Asset Management

Measure	2012	2013	2014	2015	2016
Distribution System Plan Implementation Progress			In Progress	In Progress	In Progress

Table 1-18 above displays the Asset Management progress from 2012 to 2016.

Distribution System Plan (DSP) Implementation Progress

Although PUC Distribution has employed distribution system planning for several years, the OEB instituted a mandatory requirement for this activity to be practised provincially, along with associated performance measures, beginning in 2013. We expect that implementation of this standardised approach will allow us to strengthen our commitment to responsible long term planning and sustainable asset management and to align our objectives with those of the OEB, ultimately maximising benefit to our ratepayers. All distributors are required to file a DSP when

filing a cost of service application for the rebasing of their rates. PUC Distribution has migrated and expanded upon its previous distribution system planning to create a formal DSP that meets all OEB requirements. The new DSP will be accompanied by performance measures and is included with this cost of service rate application.

iv. Cost Control

Table 1-19 : Scorecard Performance Category – Cost Control

Measure	2012	2013	2014	2015	2016
Efficiency Assessment	3	4	4	4	4
Total Cost per Customer	$615	$687	$664	$699	$695
Total Cost per Km of Line	$27,523	$30,950	$29,886	$31,377	$31,314

Table 1-19 above displays the Cost Control data from 2012 to 2016.

Efficiency Assessment

The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC ("PEG") on behalf of the OEB to produce a single efficiency ranking. The PEG econometrics model attempts to standardize costs to facilitate more accurate cost comparisons among distributors by accounting for differences such as number of customers, treatment of high and low voltage costs, kWh deliveries, capacity, customer growth, length of lines, etc. All Ontario electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual costs versus the PEG model predicted costs. Table 1-20 below summarizes the distribution of all distributors across the 5 groupings for 2016:

Table 1-20 - Distribution of Distributors

Group	Demarcation Points for Relative Cost	Group Ranking	# of Ontario LDCs in

	Performance		Group
1	Actual costs are 25% or more below predicted costs	Most Efficient	6
2	Actual costs are 10% to 25% below predicted costs	More Efficient	14
3	Actual costs are within +/-10% of predicted costs	Average Efficiency	32
4	Actual costs are 10% to 25% above predicted costs	Less Efficient	13
5	Actual costs are 25% or more above predicted costs	Least Efficient	3

In 2016, for the fourth year in a row, PUC Distribution was placed in Group 4. PUC Distribution's efficiency performance based on the PEG model was over the predicted costs by 13.4%, 22.7%, 14.6%, 16.2% and 14% between the years 2012 to 2016 respectively.

Included in PUC Distribution's operating, maintenance and administrative expenses is a charge from PUC Services that is based on depreciating and financing of the vehicles, tools, computer equipment, office equipment etc. that is utilized to provide services to PUC Distribution. For

utilities that own the vehicles and equipment to service their customers, these expenses are included in depreciation and financing costs. As the total costs would be the same, removing the depreciation and financing costs from PUC Distribution's operating costs would better align costs comparisons in the PEG model with other utilities. In addition, PUC Distribution has been including property taxes in account 5675 – Maintenance of General Plant. Commencing in 2017, PUC Distribution will be recording these expenses in account 6105 - Taxes Other Than Income Taxes which is not included in the PEG calculation. Projections for 2017 indicate that PUC Distribution would be in Group 3 after removing the non-operating type costs noted above from the PEG calculation. PUC Distribution's projected efficiency ranking remains at Group 3 in 2018 through to the end of the projection period in 2021 with the removal of the non-operating costs from the calculation.

PUC Distribution's target for 2018 is to improve efficiency performance in order to be rated as a Group 3 utility after the removal of the non-operating costs from the PEG calculation.

Total Cost per Customer

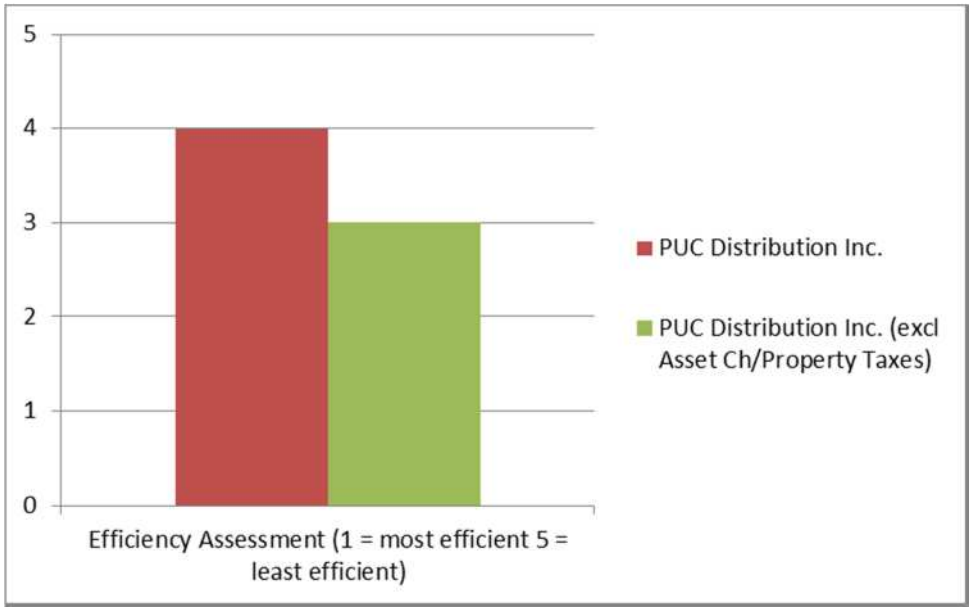
Total cost per customer is calculated as the sum of PUC Distribution's capital and operating costs, including certain adjustments to make the costs more comparable between distributors (i.e. under the PEG econometrics model), and dividing this cost figure by the total number of customers that PUC Distribution serves. PUC Distribution's cost performance results, from 2012 to 2016, have increased from $615 to $695 per customer. Overall, the company's total cost per customer has increased on average by 3.26% per annum over the period 2012 through 2016. For the period of 2013 to 2016, the total cost per customer has increased by approximately 0.45% per year. PUC Distribution will continue to replace aging distribution assets proactively in a manner that balances system risks and customer rate impacts. The company continues to implement productivity and improvement initiatives to help offset some of the costs associated with future system improvement and enhancements. Customer engagement initiatives that commenced in 2016 will continue in order to ensure customers have an opportunity to share their viewpoint on PUC Distribution's capital spending plans.

PUC Distribution's target for this metric in 2018 is $660 excluding the non-operating costs discussed above.

Figure 7 and Figure 8 below measure PUC Distribution's 2016 Operational Effectiveness in the cost control area.

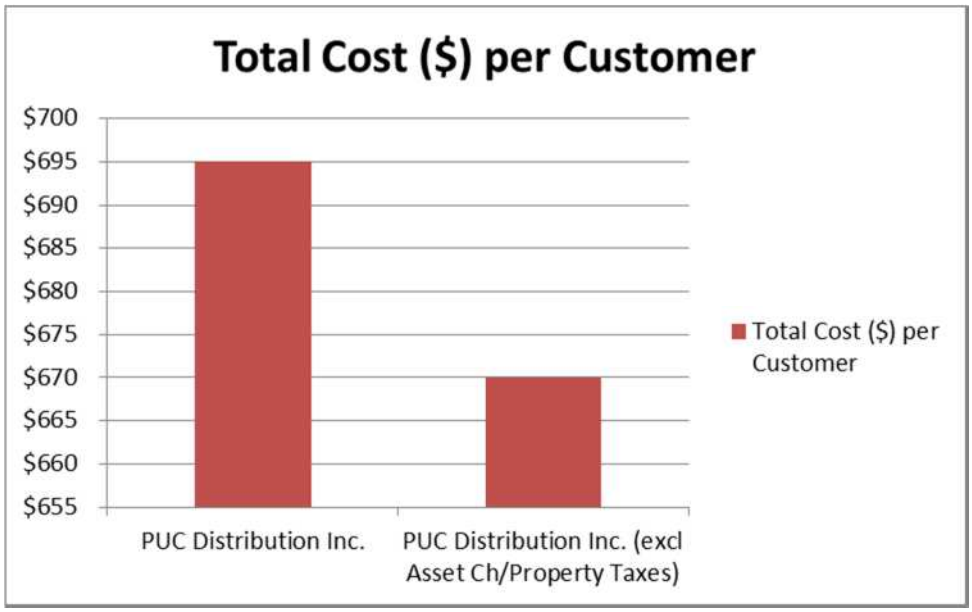
As indicated, PUC Distribution's efficiency rating in 2016 placed it in Group 4, compared to the provincial average of 3. However with the removal of the non-operating costs as detailed above, PUC Distribution has a cost per customer within 10% of predicted cost and would be placed in Group 3.

Figure 7 - PUC Distribution Efficiency Assessment



As indicated below, PUC Distribution's cost per customer in 2016 was $695 per customer which is above the provincial average of $669. However with the removal of the non-operating costs as detailed above, PUC Distribution has a cost per customer of $670, which is relatively equal to the provincial average. As noted above PUC Distribution is striving to reduce the cost per customer and is projecting its efficiency rating to improve compared to expected costs but remain in Group 3.

Figure 8 - PUC Distribution Total Cost per Customer



Operating, Maintenance & Administrative Cost per Customer from the 2016 Yearbook of Electricity Distributors

LDC costs can differ significantly based on service territory size, physical attributes of the service territory, rural vs. urban customer mix, local weather conditions, etc. PUC Distribution is one member of the group of provincial LDCs that has less than 50 customers per kilometer of line. PUC Distribution has used data from the 2016 Yearbook of Electricity Distributors to compare OM&A costs against LDCs with less than 50 customers per kilometer of line. Hydro One and Algoma Power have not been included in this comparison.

As discussed above, included in PUC Distribution's OM&A expenses is a charge from PUC Services that is based on depreciating and financing of the vehicles, tools, computer equipment, office equipment etc. that is utilized to provide services to PUC Distribution. For utilities that own the vehicles and equipment to service their customers, these expenses are included in depreciation and financing costs. As the total costs would be the same, removing the

depreciation and financing costs from PUC Distribution's costs would better align cost comparisons. The following comparison utilizes the data from the '2016 Yearbook of Electricity Distributors. PUC Distribution's OM&A cost per customer is calculated by taking the total OM&A expense and subtracting the depreciation and financing costs and dividing this cost by the total number of customers. To better align with similar utilities, PUC Distribution compared to utilities that have less than 50 customers per kilometer of line. As outlined in Table 1-21 below, when analysing the OM&A cost per customer for the 2016 year, PUC Distribution's cost per customer is $322.51. The average for all utilities in the province with less than 50 customers per kilometer of line is $324.74 per customer.

Table 1-21– 2016 OM&A Cost per Customer Comparison (<50 Customers per Km of Line)

For the year ended December 31, 2016	Number of Customer	Km of Line	Service Territor	Rural Service Territo	Urban Service Territo	% Rural Service Territor	Cust/Km line	Cust/Km	OM&A/ Custome
Average	**65,602**	**1,873**	**266**	**150**	**116**	**40.51%**	**38**	**266**	**$324.74**
PUC Distribution Inc.	**33,487**	**743**	**342**	**284**	**58**	**83.0%**	**45**	**98**	**$322.51**
Kitchener-Wilmot Hydro Inc.	94,058	1,948	409	284	125	69.4%	48	230	$186.10
Hydro One Brampton Networks Inc.	158,630	3,367	269	-	269	0.0%	47	590	$197.76
Newmarket-Tay Power Distribution Ltd.	35,465	855	74	3	71	4.1%	41	479	$218.43
Wasaga Distribution Inc.	13,346	289	61	8	53	13.1%	46	219	$228.90
Veridian Connections Inc.	119,533	2,571	639	386	253	60.4%	46	187	$229.61
Waterloo North Hydro Inc.	56,230	1,619	672	607	65	90.3%	35	84	$236.41
North Bay Hydro Distribution Limited	24,070	573	330	279	51	84.5%	42	73	$241.69
Westario Power Inc.	23,168	530	64	-	64	0.0%	44	362	$249.61
PowerStream Inc.	364,505	7,744	807	304	503	37.6%	47	452	$251.71
Entegrus Powerlines Inc.	40,833	953	96	-	96	0.0%	43	425	$257.89
Oakville Hydro Electricity Distribution Inc.	68,810	1,883	143	34	109	23.8%	37	481	$261.30
Milton Hydro Distribution Inc.	36,818	1,051	371	315	56	84.9%	35	99	$262.20
Guelph Hydro Electric Systems Inc.	54,414	1,132	93	-	93	0.0%	48	585	$265.81
Energy+ Inc.	64,123	1,727	562	458	104	81.5%	37	114	$270.80
Burlington Hydro Inc.	66,824	1,506	188	90	98	47.9%	44	355	$272.59
Halton Hills Hydro Inc.	22,112	1,613	281	255	26	90.9%	14	79	$277.18
Niagara-on-the-Lake Hydro Inc.	9,234	333	133	119	14	89.5%	28	69	$277.67
Whitby Hydro Electric Corporation	42,178	1,095	148	64	84	43.2%	39	285	$281.21
COLLUS PowerStream Corp.	16,864	350	45	-	45	0.0%	48	375	$291.78
Welland Hydro-Electric System Corp.	22,853	480	81	-	81	0.0%	48	282	$295.05
Thunder Bay Hydro Electricity Distribution Inc.	50,769	1,188	387	208	179	53.7%	43	131	$305.11
Greater Sudbury Hydro Inc.	47,362	1,001	410	120	290	29.3%	47	116	$306.24
Enersource Hydro Mississauga Inc.	204,728	5,220	292	-	292	0.0%	39	701	$307.15
Grimsby Power Incorporated	11,169	246	69	50	19	72.5%	45	162	$316.98
Centre Wellington Hydro Ltd.	6,798	153	11	-	11	0.0%	44	631	$319.39
Niagara Peninsula Energy Inc.	53,617	2,004	827	759	68	91.8%	27	65	$319.80
Toronto Hydro-Electric System Limited	761,920	28,605	630	-	630	0.0%	27	1,209	$323.66
Canadian Niagara Power Inc.	28,808	1,025	357	284	73	79.6%	28	81	$333.54
Innpower Corporation	16,443	843	292	217	75	74.3%	20	56	$354.17
Lakeland Power Distribution Ltd.	13,406	357	163	144	19	88.3%	38	82	$365.17
Bluewater Power Distribution Corporation	36,355	773	205	109	96	53.2%	47	177	$378.55
Hearst Power Distribution Company Limited	2,704	68	93	-	93	0.0%	40	29	$387.53
Northern Ontario Wires Inc.	6,007	370	28	-	28	0.0%	16	215	$417.52
Espanola Regional Hydro Distribution Corporation	3,283	140	102	76	26	74.5%	23	32	$422.35
Fort Frances Power Corporation	3,746	80	32	-	32	0.0%	47	116	$467.12
Wellington North Power Inc.	3,739	79	14	-	14	0.0%	47	267	$470.06
Sioux Lookout Hydro Inc.	2,790	275	536	530	6	98.9%	10	5	$549.11
Chapleau Public Utilities Corporation	1,247	27	2	-	2	0.0%	46	624	$602.27
Atikokan Hydro Inc.	1,639	92	380	-	380	0.0%	18	4	$667.53

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 the company operates to serve its customers. PUC Distribution's cost performance results, from 2012 to 2016, have increased from $27,523 to $31,314 per km of line.

PUC Distribution continues to experience a low level of growth in its total kilometers of lines due to a low annual customer growth rate. Such a low growth rate has reduced the ability to fund capital renewal and increasing operating costs through customer growth. As a result, total cost per km of line has increased an average of 3.45% since 2012 with the increase in capital and operating costs. For the period of 2013 to 2016, the total cost per km of line has increased by approximately 0.45% per year.

PUC Distribution's target for this metric in 2018 is $29,904 excluding the non-operating costs discussed above.

C. Public Policy Responsiveness

i. Conservation and Demand Management

Table 1-22: Scorecard Performance Category – Conservation & Demand Management

Measure	2012	2013	2014	2015	2016
Net Cummulative Energy Savings (Percent of Targe Achieved)				17.18%	52.97%

Table 1-22 above shows the net cumulative energy savings for years 2015 and 2016.

In the Board's Scorecard Report, Board staff recommended four measures to assess a distributor's public policy responsiveness: two CDM measures and two measures for connection of renewable generation.

Net Cumulative Energy Savings (Percent of Target Achieved)

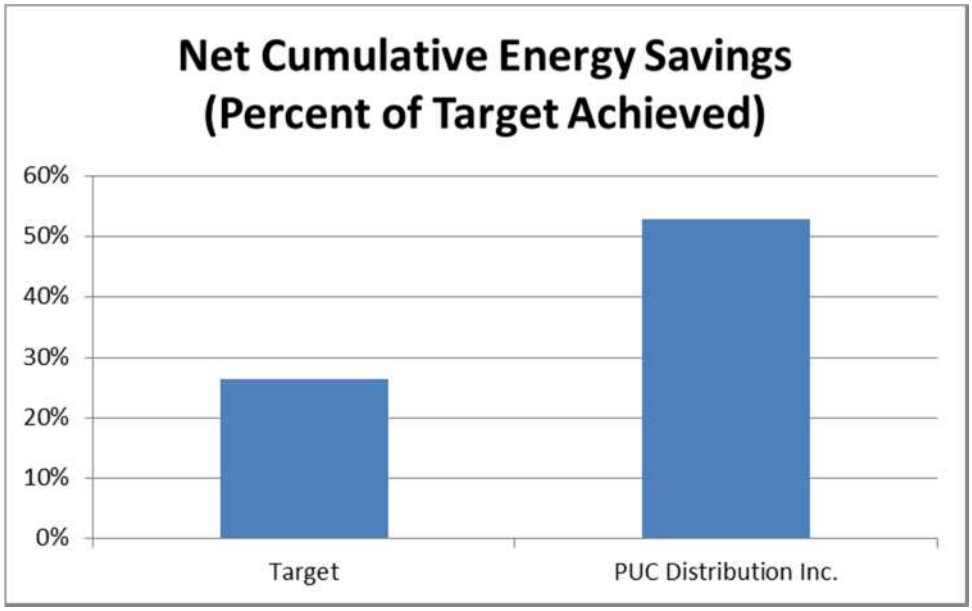
PUC Distribution is committed to helping its customers understand their energy usage by offering programs that enable them to become more energy efficient. PUC Distribution has a conservation target of 26.4 gigawatt hours by the end of 2020. Results for 2016 show progress of 52.97% towards that target. This achievement was made possible by the strong participation by local commercial/industrial customers in retrofit and auditing programs. Residential customers also participated in saveONenergy coupon events opting to replace lights in their homes with

more energy efficient ones, as well as purchasing other energy efficient equipment. The combined efforts of participants from both the residential and business sectors made the achievement of substantial energy savings possible. Notable projects were city wide street lighting conversion to LED, not only in Sault Ste. Marie but Prince Township and Batchewana First Nations. Municipal parking lots followed suit with upgrading their parking lot lighting to LED, while small businesses began changing their florescent lamps and incandescent bulbs to efficient LED tubes and lamps. PUC Distribution remains committed to providing its customers with cost effective conservation programs to help them save electricity and lower their electricity bills. PUC Distribution will continue to innovate new ways to promote and support customers in reducing their consumption today and for the future. As a member of CustomerFirst, PUC Distribution is part of a joint CDM Plan that has been approved by the Independent Electricity System Operator ("IESO"). The joint plan will achieve 141,877 MWh of savings which is equal to the combined targets that were allocated to each CustomerFirst member under the new framework. Through the CustomerFirst joint CDM Plan, PUC Distribution will continue to work collaboratively with the other CustomerFirst utilities to find efficiencies and reduce costs. The group will be sharing resources and working together in all areas of CDM including sales, marketing, customer and project support to provide value to ratepayers.

PUC Distribution's target for this metric in 2018 is 4,651.8 MWhs which is approximately 73% of the Net Cumulative Energy Savings target.

As indicated in Figure 9 below, PUC Distribution has achieved 52.97% of its conservation target which exceeds the provincial average of 40.38%. PUC Distribution is on track to meet its mandated target.

Figure 9 - Net Cumulative Energy Savings



ii. Connection of Renewable Generation

Table 1-23: Scorecard Performance Category – Renewable Generation

Measure	2012	2013	2014	2015	2016
Renewable Generation Connection Impact Assessments Completed on Time				0.00%	100.00%
New Micro-Embedded Generation Facilities Connected on Time		100%	100%	100.00%	

Table 1-23 above shows the percentage of renewable generation connection impact assessments completed on time and the new micro-embedded generation facilities connected on time from 2012 to 2016.

Renewable Generation Connection Impact Assessments Completed on Time

Electricity distributors are required to conduct Connection Impact Assessments ("**CIAs**") within 60 days of receiving authorization for their project from the ESA. As of December 31, 2017, PUC Distribution has connected 1 microFit offer to connect for 3.19 kW of generation, 0 FIT

and 0 large generation customers with a connected capacity of 0 MW. For the year 2016 four CIA requests were received for a total of 820kW of FIT generation, and all applications were processed within the prescribed timelines.

In 2015, the cause for not completing the CIA(s) within the application timeline prescribed by Ontario Regulation 326/09 was due to a vacancy in the Engineering Department. An Engineer In Training ("EIT") was recruited to fill the vacancy later in 2015 and has re-established an active CIA management process.

PUC Distribution's target for this metric in 2018 is to complete all assessments within the prescribed timelines.

New Micro Embedded Generation Facilities Connected on Time

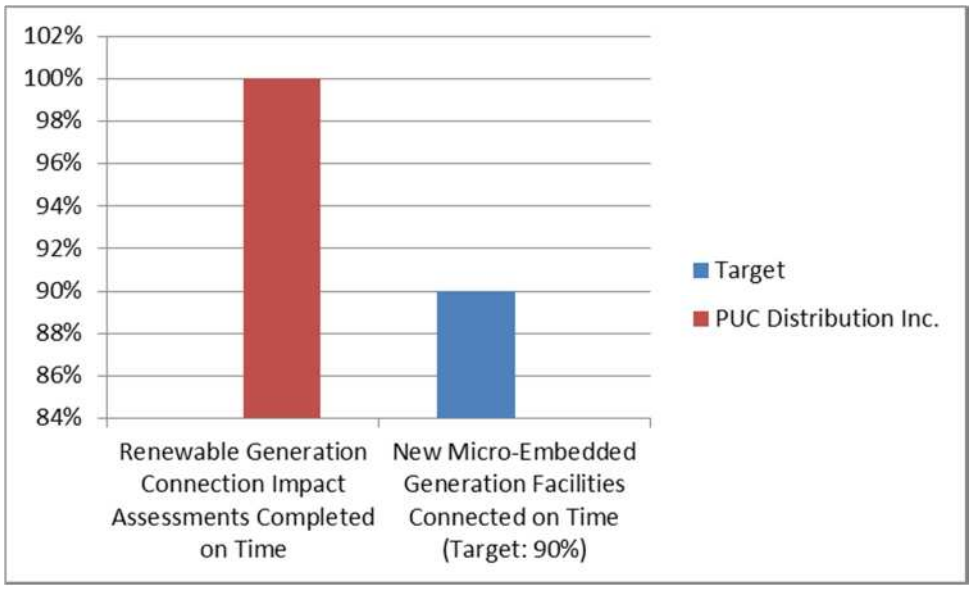
In 2014, PUC Distribution connected 7 new micro-embedded generation facilities 100% of the time within the prescribed time frame of 5 business days. In 2015, PUC Distribution connected 6 new micro-embedded generation facilities of which all were connected within the prescribed timeframe. In 2016, interest in the microFIT program was much lower than in previous years. PUC Distribution received only one application and provided an offer to connect, but no follow-up request for connection was received. This resulted in no microFIT connections during the 2016 year, effectively leaving a blank space on the scorecard. Outside of the micoFIT program, one application for a net metering load displacement installation was made. PUC Distribution's process to connect these projects is very streamlined and transparent for its customers. PUC Distribution works closely with customers and contractors to address any connection issues and ensure projects are connected in a timely manner.

PUC Distribution's target for this metric in 2018 is to connect micro-embedded generation facilities within 5 business days of all service connection requirements being met.

Figure 10 below compares PUC Distribution's 2016 Connection of Renewable Generation to the provincial target. In 2016 PUC Distribution completed 100% of requested Renewal Generation

Connection Impact Assessments on Time. PUC Distribution had no requests to connect new micro-generation facilities in 2016.

Figure 10 - Renewable Generation Connections



D. Financial Performance

i. Financial Ratios

Table 1-24: Scorecard Performance Category – Financial Ratios

Measure		2012	2013	2014	2015	2016
Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.19	1.06	1.68	0.90	1.52
Leverage: Total Debt (includes short term and long term debt) to Equity Ratio		2.01	1.99	2.42	2.31	2.34
Profitability: Regulated Return on Equity	Deemed	8.57%	8.98%	8.98%	8.98%	8.98%
	Achieved	4.99%	7.00%	5.47%	4.46%	0.98%

Table 1-24 above details the financial ratios from 2012 to 2016.

In the Board's Scorecard Report, Board staff recommended three measures to assess a distributor's financial viability: current ratio, total debt to equity ratio, and achieved regulated return on equity.

Liquidity: Current Ratio (Current Assests/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. Since 2012, PUC Distribution has only seen a current ratio less than 1 in 2015. This drop, from 1.68 the year prior, was due to a construction loan of $15 million in current liabilities. The short term loan was converted to a long term loan in 2016 as planned. The result of this was a reduction of current liabilities of $15 million which increased the current ratio to a 1.52 in 2016. By increasing over 1, PUC Distribution is in a good position to cover the company's short-term debts and financial obligations.

PUC Distribution's target for this metric in 2018 is to maintain the current ratio above 1.

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. PUC Distribution has a debt to equity structure of 70% to 30% that approximates the deemed 60% to 40% capital mix as set out by the OEB – this translates to a 2016 debt to equity ratio of 2.34. PUC Distribution's long range plan is to push the debt to equity towards the 60/40 level.

PUC Distribution's target for this metric in 2018 is to reduce the debt to equity to 67%/33%.

Profitability: Regulatory Return on Equity – Deemed (included in rates)

PUC Distribution's current distribution rates were approved by the OEB and include an expected (deemed) regulatory return on equity ("ROE") of 8.98%. The OEB allows a distributor to earn within +/- 3 percentage points 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

PUC Distribution's return on equity in 2016 at 0.98% was more than 3 percentage points lower than the expected return of 8.98%. The variance in return on equity is the result of PUC Distribution's OM&A expenses in 2016 being approximately $1.4 million higher than included in the approved 2013 cost of service rate application. In addition, PUC Distribution did not increase its rates in one year of the current IRM rate period and postponed its Cost of Service rate application due to the local economic circumstances. PUC Distribution plans to address the deficiency in ROE through this cost of service rate application and restructuring of its debt.

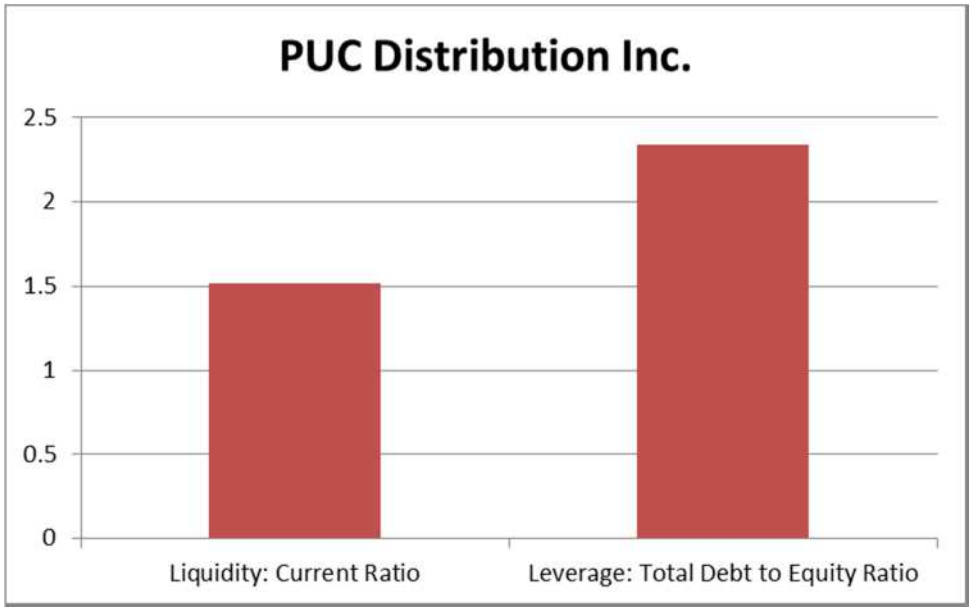
PUC Distribution's target for this metric is a regulatory rate of return equal to the deemed ROE.

Figure 11 - below compares PUC Distribution's current ratio for liquidity to the total debt to equity ratio.

PUC Distribution's current ratio in 2016 was 1.52 which is slightly above the provincial average of 1.48.

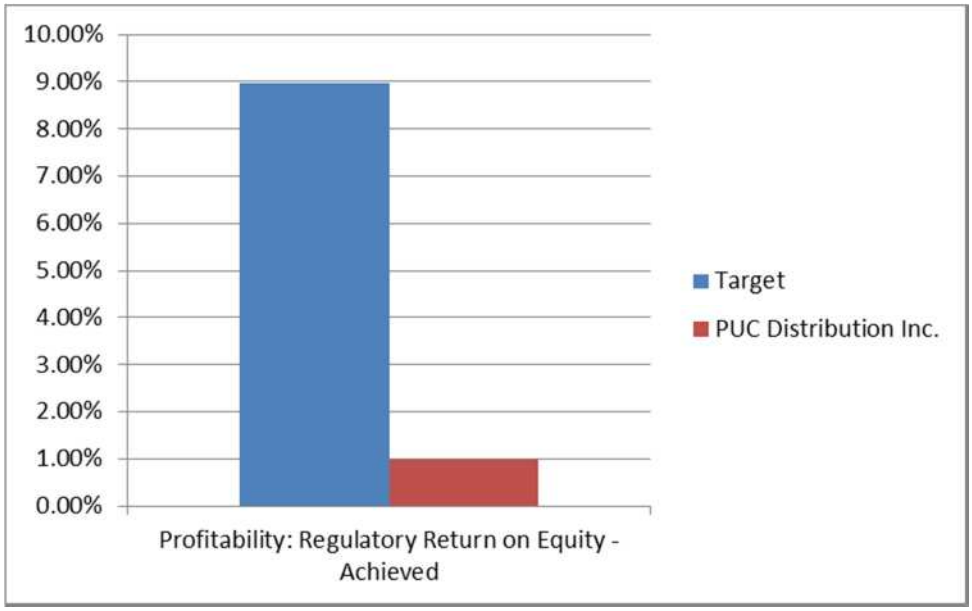
PUC Distribution's debt to equity ratio is well above the provincial average. As noted above and in PUC Distribution's business plan, PUC Distribution intends to reduce the debt to equity ratio. Steps will be taken toward reducing the current debt with the shareholder to take advantage of current low interest rates, reduce the current debt to equity structure and strengthen the company's balance sheet.

Figure 11 - Liquidity and Leverage



As shown in Figure 12 below PUC Distribution's return on equity at 0.98% in 2016 is well below the provincial average and deemed rate of return. As stated previously in this Exhibit, actual expenses considered necessary by PUC Distribution to service customers have been in excess of those included in rates since the last cost of service rate application. In addition, an IRM increase was not taken in 2016 and the cost of service rate application was postponed for one year. PUC Distribution plans to address the deficiency in return on equity through this cost of service rate application and restructuring of its debt.

Figure 12 - Return on Equity Achieved



2.1.8 Financial Information

2.1.8.1 Non-Consolidated Audited Financial Statements

Copies of PUC Distribution's 2013, 2014, 2015 and 2016 Audited Financial Statements are provided in Appendix 6.

(a) Reconciliation between Audited Financial Statements and Regulatory Accounting

Reconciliations of PUC Distribution's Audited Financial Statements to the annual Regulatory Reporting Requirement ("RRR") Trial Balance for 2013, 2014, 2015 and 2016 are provided in Appendix 7.

(b) Annual Report and MD&A for Parent Company

PUC Distribution Inc. does not have any annual reports. The most recent annual report from PUC Inc. is 2013. It has been provided in Appendix 8.

(c) Rating Agency Reports

PUC Distribution does not hold public debt, therefore, does not require a rating agency report.

(d) Prospectus, Information Circulars for Recent and Planned Issuances

PUC Distribution has no past or planned prospectuses, information circulars, or other similar documents.

(e) Changes in Tax Status

PUC Distribution has not had a change in Tax Status since its last Cost of Service Application.

(f) Accounting Orders

PUC Distribution confirms that it implemented the regulatory accounting changes for depreciation and overhead capitalization in 2013. PUC Distribution has prepared this Application on the MIFRS basis, as required.

In accordance with EB-2012-0162, PUC Distribution established Account 1508, Other Regulatory Assets, sub-account Productivity Initiatives Variance Account. This account has been used to record the notional revenue in the amount of $400,000 collected from PUC Distribution Inc.'s customers and related expenditures from July 1, 2013 to April 30, 2017. Refer to Section 2.1.3.10 above.

(g) Uniform System of Accounts

PUC Distribution confirms there are no departures from the Uniform System of Accounts.

(h) Accounting Standards

The Accounting Standard Board ("AcSB") deferred mandatory adoption of IFRS for qualifying rate-regulated entities to January 1, 2015. However, per the Board's letter of July 17, 2012, electricity distributors electing to remain on Canadian Generally Accepted Accounting Principles

("CGAAP") were required to implement regulatory accounting changes for depreciation expenses and capitalization policies by January 1, 2013.

PUC Distribution confirms that it implemented the regulatory accounting changes for depreciation and overhead capitalization in 2013. PUC Distribution transitioned to IFRS on January 1, 2015 and restated 2014 Financial Statement comparators to IFRS. This Application is being filed using MIFRS Accounting Standards. Historical years are represented under the following Accounting Standards: 2013 using CGAAP and MIFRS 2014 through to 2018.

(i) Accounting Treatment of Non-Utility Businesses

PUC Distribution does not have any non-utility business activities.

2.1.9 Distributor Consolidation

PUC Distribution confirms that is has not amalgamated with another distributor since it was last rebased.

APPENDIX 1

Management Services Agreement between PUC Services Inc and PUC Distribution Inc.

MANAGEMENT, OPERATIONS AND MAINTENANCE AGREEMENT

THIS AGREEMENT made as of January 1st, 2001.

BETWEEN:

PUC SERVICES INC., a corporation incorporated under the laws of the Province of Ontario (hereinafter called the **"Manager"**),

OF THE FIRST PART;

-and-

PUC DISTRIBUTION INC., a corporation continued under the laws of the Province of Ontario (hereinafter called **"Distribution"**),

OF THE SECOND PART.

RECITALS

1. Distribution and the Manager have agreed to enter into this Agreement pursuant to which the Manager will assume responsibility for all aspects of the management operation and maintenance of Distribution's Business other than marketing and sales and subject to overall responsibility for management of Distribution by its senior officers and board of directors.

NOW THEREFORE THIS AGREEMENT WITNESSES THAT, in consideration of the covenants and agreements herein contained, the parties hereto agree as follows:

ARTICLE ONE

DEFINITIONS AND SCHEDULES

1.1 Definitions

In this Agreement, unless something in the subject matter is inconsistent therewith, all capitalized terms shall have the meanings set forth below:

"Affiliate Relationships Code" means the Affiliate Relationships Code of the Ontario Energy Board as the same may be amended from time to time.

"Agreement" means this Agreement and all amendments made hereto in accordance with the provisions hereof.

"Business" means owning a distribution system in order to distribute electricity to customers, as well as business activities incidental thereto.

"Business Day" means a day other than Saturday, Sunday or a legal holiday in the City of Sault Ste. Marie, Ontario.

"Emergency Management Powers" means the powers of the Manager described in Section 2.2 (1)(d).

"Event of Default" means any of the events described in Section 6.1.

"Force Majeure" means a cause which is unavoidable or beyond the reasonable control of a party hereto and which by the exercise of due diligence such party is unable to prevent or overcome, including, without limitation, acts of God, acts of a public enemy, war, hostilities, invasion, insurrection, riot, the order of any competent civil or military government, explosion, fire, strikes, lockouts, labour disputes, malicious acts, vandalism, failure of equipment beyond the reasonable control of a party hereto, accident to any facilities, storms, or other adverse weather conditions, or other causes of a similar nature which wholly or partially prevent the parties or either of them from carrying out the terms of this Agreement (other than for the payment of monies due hereunder); provided that either party shall have the right to determine and settle any strike, lockout and labour dispute in which that party may be involved in its sole discretion and provided further that Force Majeure shall exclude lack of funds or economic hardship.

"Insolvent" means, in relation to any Person, being insolvent, bankrupt, making a proposal under the *Bankruptcy and Insolvency Act* (Canada) or having a trustee or receiver or manager appointed in respect of its assets.

"Prudent Industry Practice" means any of the practices, methods and acts which, in the exercise of reasonable judgment in the light of the facts known to the Manager, at the time that a decision was made, could reasonably have been expected to accomplish the desired result at a reasonable cost, consistent with applicable laws, licensing and regulatory considerations, environmental considerations, reliability, safety and expedition. Prudent Industry Practice is not intended to be limited to the optimum practice, method or act, to the exclusion of all others, but rather to be a spectrum of possible practices, methods or acts employed by owners and operators of facilities similar in size, type and operational characteristics to Distribution's facilities, and having due regard for applicable electrical, safety and maintenance codes and standards, manufacturers' warranties, and applicable laws and shall, in any event, evidence the degree of care, diligence and skill that a reasonably prudent advisor and manager having responsibility for the management of a similar business would exercise in comparable circumstances.

"**Term**" shall mean the period from the date hereof to the tenth anniversary hereof or such earlier date as this Agreement may be terminated in accordance with its terms.

1.2 Headings

The division of this Agreement into Articles, Sections, paragraphs and subparagraphs and the insertion of headings are for convenience of reference only and shall not affect the construction or interpretation of this Agreement. The terms "hereof", "hereunder" and similar expressions refer to this Agreement and not to any particular Article, Section or other portion hereof and include any agreement supplemental 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.

1.3 Interpretation

Words importing the singular number only shall include the plural and vice versa, words importing gender shall include all genders. Where the word "including" or "includes" is used in this Agreement it means "including without limitation" or "includes without limitation", respectively. Any reference to any Document shall include a reference to any schedule, amendment or supplement thereto or any agreement in replacement thereof, all as permitted under the Documents.

1.4 Accounting Principles

Wherever in this Agreement reference is made to generally accepted accounting principles, such reference shall be deemed to be to 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. Where the character or amount of any asset or liability or item of revenue or expense is required to be determined, or any consolidation or other accounting computation is required to be made for the purpose of this Agreement or any document, such determination or calculation shall, to the extent applicable and except as otherwise specified herein or as otherwise agreed in writing by the parties, be made in accordance with generally accepted accounting principles applied on a consistent basis.

1.5 Funds

All dollar amounts referred to in this agreement are in lawful money of Canada.

ARTICLE TWO

THE MANAGER'S FUNCTIONS AND POWERS

2.1 Appointment of the Manager

Distribution hereby appoints the Manager and the Manager hereby accepts its responsibility for all aspects of the operation, maintenance, management and management of the Business in accordance with Prudent Industry Practice and the terms of this Agreement throughout the Term including without limitation providing all necessary staff to operate the Business but excluding marketing and sales services.

2.2 General Management Services

(1) The Manager shall have authority during the Term to manage, control, administer and operate the Business in accordance with Prudent Industry Practice, subject to the overall responsibility for management of Distribution by its senior officers ("Distribution Management") and the Distribution Board of Directors (the "Distribution Directors") and subject to and limited by the provisions of this Agreement.

Without limiting the generality of the foregoing, the Manager shall be vested with the following powers which it shall exercise on behalf of Distribution:

(a) to report to Distribution Management and the Distribution Directors with respect to the business and affairs of Distribution and the Business as may be requested from time to time by Distribution Management and the Distribution Directors;

(b) to provide all administrative services for the Business and Distribution including accounting and bookkeeping services;

(c) to negotiate, execute, amend, administer, perform and carry out the terms of all agreements and commitments, the performance of which by or on behalf of Distribution in respect of the Business and the Business is necessary or advisable; and

(d) to exercise emergency management powers in respect of any aspect of the operation and management of Distribution's facilities ("Emergency Management Powers") in order to take such action as a prudent owner of such facilities would normally take in the circumstances provided that (i) the Manager reasonably believes that immediate action is necessary to safeguard life or property or to prevent or minimize an interruption in the delivery of electricity, (ii) such action does not involve expenditures exceeding $1 million per occurrence in respect of any emergency unless the Manager has first received the approval of Distribution, and (iii) upon the exercise of Emergency Management Powers, the Manager shall forthwith notify Distribution Management and Distribution Directors in writing

of the nature of the Emergency Management Powers exercised by it, the reasons for exercising Emergency Management Powers and the costs incurred or to be incurred by it in the exercise of the Emergency Management Powers.

2.3 Operations and Maintenance Services

Without limiting the generality of Section 2.2, the Manager shall provide or arrange for all of the operations and maintenance services necessary to prudently and efficiently operate and maintain Distribution's facilities, including but not limited to:

(a) co-ordinate the purchase and sale of electricity under applicable contracts and pay on behalf of Distribution and collect all amounts payable and receivable thereunder;

(b) operate and maintain the Business in accordance with Prudent Industry Practice, applicable laws and all Distribution agreements, to minimize unscheduled outages and to provide maintenance for Distribution's facilities in the most cost-effective manner to prevent deterioration beyond normal wear and tear; provided that such efforts shall be necessarily limited by the operating life, capacity and maintenance requirements of Distribution's facilities and by the requirements of all applicable laws;

(c) use all reasonable care necessary to keep Distribution's facilities clean, orderly and free from debris, rubbish or waste to the extent consistent with the operation of the Business;

(d) use all reasonable care not to generate, store, transport, accumulate, dispose, discharge or release any hazardous substance on, in or from any property in connection with Distribution's facilities, except in compliance with all applicable environmental laws and regulations;

(e) assist Distribution in obtaining and maintaining all necessary regulatory approvals including those required from the Ontario Energy Board for the Business and renewals therefor including preparing and submitting all associated applications and filings;

(f) use its reasonable efforts to secure and maintain from vendors, suppliers and subcontractors the best indemnities, warranties and guarantees as may be commercially available in accordance with Prudent Industry Practice regarding supplies, equipment and services purchased for the Business and assist Distribution in preserving and enforcing such indemnities, warranties or guarantees;

(g) provide administrative services for the Business and for Distribution in respect of the Business including:

(i) arrange insurance for the Business and Distribution consistent with Prudent Industry Practice;

(ii) maintain and preserve equipment maintenance, accounting, banking and other necessary records, reports, documents, data and the like for the Business and Distribution;

(iii) perform cash management services for the Business and Distribution;

(iv) on a timely basis prepare monthly and annual financial statements and deliver them to the Distribution Directors;

(v) assist in the administration of all agreements to which Distribution is a party or by which it is bound, including negotiations and communications with third parties in connection therewith; and

(vi) make all banking and financing arrangements;

(h) employ, and ensure adequate training and testing of all qualified personnel (duly licensed where required) required for the operation and maintenance of Distribution's facilities consistent with Prudent Industry Practice;

(i) implement an inventory control system to identity, catalogue and disburse spare parts for the maintenance of Distribution's facilities and procure, as agent for Distribution, initial and replacement spare parts and refurbish, where practical or economical, spare parts to allow their reuse;

(j) perform for Distribution such other services as may from time to time be reasonably requested or are reasonably necessary or appropriate in connection with the operation and maintenance of Distribution's facilities;

(k) promptly provide Distribution with such other information relative to the Business as Distribution may reasonably request;

provided that in the conduct of its duties hereunder, the Manager shall not, without first obtaining the written approval of the Distribution Directors undertake any activity which by the terms of the Shareholders' Agreement between Distribution and PUC Inc. requires the approval of PUC Inc.

2.4 Covenants of the Manager

The Manager covenants and agrees that in the performance of its services under this Agreement it shall:

(a) perform all services at all times in accordance with Prudent Industry Practice and in compliance with applicable laws and the Affiliate Relationships Code;

(b) comply with all instructions of Distribution Management of the Distribution Directors in relation to the performance of its services under this Agreement;

(c) observe and perform or cause to be observed and performed on behalf of Distribution in every material respect the provisions of (i) the agreements from time to time entered into in connection with the Business, and (ii) all applicable laws including the Affiliate Relationships Code;

2.5 No Liability of Manager

The Manager shall have no liability as a result of this Agreement to make or arrange for payments on account of operating expenses of Distribution or any other expenses relating to this Agreement out of its own funds.

ARTICLE THREE

TERM

3.1 Term of Agreement

This Agreement shall become effective as of the date hereof and shall continue in full force and effect until January 1st, 2011 unless sooner terminated in accordance with the provisions of this Agreement. This Agreement shall be automatically renewed for successive periods of five years unless either party provides the other with written notice to the contrary at least one hundred and eighty (180) days prior to the end of the then incumbent term.

ARTICLE FOUR

MANAGEMENT FEES

4.1 Management Fees

The parties shall negotiate, acting reasonably, the fees to be paid by Distribution to the Manager for the services hereunder. Such fees shall be determined annually and in compliance with the Affiliate Relationships Code. Any change in fees shall not be effective unless ratified by the Distribution Directors.

ARTICLE FIVE

FINANCIAL STATEMENTS, BUDGETS AND RECORDS

5.1 Books and Records

The Manager shall keep proper books, records and accounts in which full, true and correct entries in conformity with generally accepted accounting principles and all requirements of applicable laws will be made of all dealings and transactions in relation to the Business and the performance of the Manager's services under this Agreement at the Manager's head office.

5.2 Examination of Records

The Manager shall make available to Distribution and its authorized representatives at any time during normal business hours on a Business Day all records, documents or information related to the Business, wherever maintained. The Manager shall permit Distribution and its authorized representatives at any time during normal business hours on a Business Day to examine the books, records, drawings, computer-stored data, correspondence, accounting procedures and practices, cost analyses and any other supporting financial data, including invoices, payments or claims and receipts pertaining to the Business maintained by the Manager at its head office. Distribution's examination of records at the Business or at the Manager's head office shall be conducted in a manner which will not unduly interfere with the conduct of the Business or of the Manager's business in the ordinary course. The Manager shall furnish to Distribution such financial and operating data and other information with respect to the Business as Distribution shall from time to time reasonably request.

5.3 Confidentiality

The manager shall ensure that, unless required in connection with applicable laws, the books, records and accounts of Distribution (i) shall not be made available to any other person for whom the Manager provides services, and (ii) are not used by the Manager itself for any improper purpose, in compliance with the Affiliate Relationships Code.

ARTICLE SIX

DEFAULT AND TERMINATION

6.1 Event of Default

The Manager shall be in default under this Agreement upon the happening or occurrence of any of the following events, each of which shall be deemed to be an Event of Default for the purposes of this Agreement:

(a) the Manager breaches or fails to observe or perform any of the Manager's material obligations, covenants, or responsibilities under this Agreement, and,

within thirty (30) days after notice from Distribution specifying the nature of such breach or failure, to the satisfaction of Distribution Management and the Distribution Directors, the Manager fails to cure such breach or failure or to take steps to remedy such breach or failure and give reasonable assurances to Distribution that such default shall be cured within a period of time satisfactory to Distribution Management and the Distribution Directors;

(b) the Manager:

(i) becomes Insolvent;

(ii) is subject to any proceeding, voluntary or involuntary, under the provisions of the *Bankruptcy and Insolvency Act* (Canada), the *Companies Creditors Arrangement Act* (Canada), or any other Act for the benefit of creditors;

(iii) goes into liquidation;

(iv) winds up either voluntarily or under an order of a Court of competent jurisdiction;

(v) makes a general assignment for the benefit of its creditors; or

(vi) otherwise takes any corporate action that acknowledges its Insolvency; or

(c) gross negligence, wilful default or fraud by the Manager in the performance of any of its obligations, covenants, or responsibilities under this Agreement.

6.2 Termination by Distribution

Upon the occurrence of an Event of Default of the Manager but subject to section 6.3, Distribution may without recourse to legal process but without limiting any other rights or remedies which it may have at law or otherwise, terminate this Agreement by delivery of written notice of termination to the Manager.

6.3 Restriction on Termination during Force Majeure

During the occurrence of an event of Force Majeure, the obligations of the party affected by such event of Force Majeure, to the extent that such obligations cannot be performed as a result of such event of Force Majeure, shall be suspended, and such party shall not be considered to be in default hereunder, for the period of such occurrence except that the occurrence of an event of Force Majeure affecting Distribution (but not affecting the performance of the Manager's obligations hereunder) shall not relieve it of its obligation to make payments to the Manager hereunder. The non-performing party shall give the other party prompt written notice of the particulars of the event of Force Majeure and its expected duration, shall continue to furnish regular reports with respect thereto on a timely basis during the continuance of the event of Force Majeure and shall use its best efforts to remedy its inability to perform. The suspension of performance is to be of no greater scope and of no longer duration than is required by the Force Majeure condition. No obligations of either party that arose before the

Force Majeure causing the suspension of performance are excused as a result of the Force Majeure.

6.4 Post-Termination Arrangements

In the event of termination of this Agreement:

(a) the Manager shall deliver to Distribution all books, records, accounts, systems and manuals which it has developed and maintained relating to Distribution, Distribution's facilities and the Business pursuant to this Agreement;

(b) the parties shall take all steps as may be reasonably required to complete any final accounting between them and to provide, if applicable, for the orderly transfer of insurance and completion of any other matter contemplated by this Agreement; and

(c) title to all materials, equipment, supplies, consumables, spare parts and other items purchased or obtained by the Manager for the Business shall pass to and vest in Distribution upon the passage of title from the vendor or supplier thereof and payment or reimbursement of costs by Distribution.

ARTICLE SEVEN

GENERAL MATTERS

7.1 Governing Law

This Agreement shall be conclusively deemed to be a contract made under, and shall for all purposes be construed and interpreted in accordance with the laws of the Province of Ontario, and the laws of Canada applicable in such Province.

7.2 Benefit of the Agreement

This Agreement shall enure to the benefit of and be binding upon the parties hereto and their respective successors and permitted assigns.

7.3 Severability

Any provision of this Agreement which is prohibited or unenforceable in any jurisdiction shall not invalidate the remaining provisions hereof and any such prohibition or unenforceability in any jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction. In respect of any provision so determined to be unenforceable or invalid, the parties agree to negotiate in good faith to replace the unenforceable or invalid provision with a new provision that is enforceable and valid in order to give effect to the business intent of the original provision to the extent permitted by law and in accordance with the intent of this Agreement.

7.4 Amendments and Waivers

No modification of or amendment to this Agreement shall be valid or binding unless set forth in writing and duly executed by both of the parties hereto and no waiver of any breach of any term or 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, shall be limited to the specific breach waived.

7.5 Further Assurances

Each of Distribution and the Manager shall from time to time execute and deliver all such further documents and instruments and do all acts and things as the other party may reasonably require to effectively carry out or better evidence or perfect the full intent and meaning of this Agreement.

7.6 Time of the Essence

Time shall be of the essence of this Agreement.

7.7 No Partnership

It is understood and agreed that nothing contained in this Agreement nor any acts of the parties shall be deemed to constitute the Manager and Distribution as partners of each other.

IN WITNESS WHEREOF this Agreement has been executed by the parties hereto as of the day of February, 2001.

PUC SERVICES INC.

Per: _____

Per: _____

PUC DISTRIBUTION INC.

Per: _____

Per: _____

MANAGEMENT, OPERATIONS AND MAINTENANCE AGREEMENT

AMENDING AGREEMENT

THIS AGREEMENT made the 10th day of November, 2011.

BETWEEN:

PUC SERVICES INC.

(hereinafter called the "Manager")

OF THE FIRST PART

- and –

PUC DISTRIBUTION INC.

(hereinafter called "Distribution")

OF THE SECOND PART

NOW THEREFORE for good and valuable consideration the receipt and sufficiency of which are hereby acknowledged, the Manager and Distribution agree as set forth herein.

1.0 BACKGROUND

1.1 Manager and Distribution are parties to a Management, Operations and Maintenance Agreement dated January 1st, 2001, a copy of which is annexed hereto (the "Original Agreement").

1.2 In order to more efficiently carry out the obligations of the Manager as set forth in the Original Agreement the Manager has entered into a Lease for certain facilities being constructed on property at 500 Second Line East, Sault Ste. Marie, Ontario (the "Facilities"). The commencement date of the Lease is December 1st, 2012 (the "Effective Date")

2.0 AMENDMENTS

2.1 As of the Effective Date the determination of the Manager's fees in paragraph 4.1 shall be cancelled and commencing as of the Effective Date the following provision shall apply:

4.1 Management Fees

In consideration of the Manager undertaking the management, operation, and maintenance of Distribution's Business and the provision of the services set forth in paragraphs 2.2 and 2.3 hereof, Distribution agrees to pay to the Manager a monthly fee consisting of the direct costs specifically attributable to Distribution plus Distribution's proportionate share (as set forth herein) of the costs incurred by the Manager for the shared services (direct costs and shared costs collectively referred to as the "Costs") incurred by the Manager in the fulfilment of the Manager's obligations pursuant to all service contracts administered by the Manager. The Costs shall be determined by the Manager and payment shall be made by Distribution monthly within fifteen (15) days of the Manager submitting an invoice for payment to Distribution. For the purpose of this paragraph Distribution's proportionate share shall be 46% subject to periodic adjustment by the Manager. If Distribution disagrees with the Manager's determination of the Costs or any adjustment to Distribution's proportionate share, the dispute shall be submitted to a single qualified, experienced arbitrator pursuant to the *Arbitration Act, 1991* (Ontario) and the decision of the arbitrator shall be binding on the parties. The cost of arbitration shall be borne equally between the parties.

For greater clarity, the calculation of any rent included in the Costs for workshop and garage facilities and administrative offices presently owned or leased by the manager or to be owned or leased by the Manager (collectively the "Facilities") during the term of this agreement and used in the operation of Distribution's Business shall be based on the following formula:

> Rent = Capital cost of the Facilities divided by the estimated useful life (in years) of the Facilities plus the cost of capital. For the purposes of this formula "costs of capital" is the capital cost of the Facilities x the cost of capital as established by the Ontario Energy Board from time to time.

2.2 Manager and Distribution agree that until the Effective date the provisions contained in the Original Agreement with respect to the determination of management fees shall continue in full force and effect.

2.3 Manager and Distribution agree that the term of the Original Agreement is hereby extended to November 30th, 2012. The provisions regarding automatic renewal set forth in paragraph 3.1 of the Original Agreement shall continue to apply.

3.0 GENERAL

3.1 This Agreement shall be read together with the Original Agreement and the parties confirm that except as modified herein all covenants and conditions in the Original Agreement remain unchanged, unmodified and in full force and effect.

3.2 Any capitalized word or term not otherwise defined herein shall have the meaning given thereto in the Original Agreement.

3.3 The parties agree to do or cause to be done from time to time all such things and shall execute and deliver all such documents, agreements and instruments reasonably requested by the other party as may be necessary or desirable to carry out the provisions and intentions of this Agreement.

3.4 This Agreement shall ensure to the benefit of and be binding upon the parties hereto and their respective successors and assigns.

IN WITNESS WHEREOF the parties hereto have executed this Agreement.

PUC SERVICES INC.

Per: _____

Per: _____

We have authority to bind the Corporation

PUC DISTRIBUTION INC.

Per: _____

Per: _____

We have authority to bind the Corporation

APPENDIX 2

OEB Decision ED-1999-0161 Decision on Distribution Assets

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
26th Floor
Toronto ON M4P 1E4
Telephone: (416) 481-1967
Facsimile: (416) 440-7656

Commission de l'Énergie de l'Ontario
C.P. 2319
2300, rue Yonge
26e étage
Toronto ON M4P 1E4
Téléphone: (416) 481-1967
Télécopieur: (416) 440-7656

Ontario

Licensing and Applications Branch

October 3, 2000

Mr. Ken Wallenius
General Manager & Secretary
Public Utilities Commission of the City of Sault Ste. Marie
765 Queen Street East
P.O. Box 9000
Sault Ste. Marie, Ontario
P6A 6P2

Dear Mr. Wallenius:

Re: Determination of Distribution Assets
ED-1999-0161

According to the information provided on the Information Request Form for the Public Utilities Commission of the City of Sault Ste. Marie (City of Sault Ste. Marie), Transitional Distribution Licence ED-1999-0161, City of Sault Ste. Marie has equipment that operates at voltages greater than 50 kV but that is used solely for the purposes of the distribution utility.

According to the *Ontario Energy Board Act* (the *Act*) such equipment, being over the 50 kV threshold, is defined as part of a transmission system; therefore, requiring the owner or operator to be licensed as a transmitter. However, under the s. 84 (a) of the Act, the Director of Licensing has the authority to determine that a part of a transmission system is a distribution system.

The Director, in accordance with s. 84 (a) of the *Act*, has determined that those assets above 50 kV held by City of Sault Ste. Marie form part of its distribution system. The City of Sault Ste. Marie Transitional Distribution Licence ED-1999-0161 is deemed to be an application for the end-state licence as specified under ss. 129 (5).

If there has been a change to the information provided regarding equipment at transmission-level voltage, please notify the Director.

If you have any questions concerning this matter, please contact Brian Hewson, Manager of Energy Licensing at 416 440-7628.

Sincerely,

Anne Powell
Director of Licensing

APPENDIX 3

Bill Impacts

Ontario Energy Board

Tariff Schedule and Bill Impacts Model (2018 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. **The OEB has established that, when assessing the combined effects of the shift to fixed rates and other bill impacts associated with changes in the cost of distribution service, a utility shall evaluate the total bill impact for a low volume residential customer consuming at the distributor's 10th consumption percentile19, to a minimum of 50 kWh per month. Refer to page 62 of Chapter 2 Filing Requirements For Electricity Distribution Rate Applications issued July 14, 2016.**

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 2016 of $0.113/kWh (IESO's Monthly Market Report for May 2016, 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 chart for the specific class.
2. Due to the change to energy consumption used in the calculation of GA rate riders for the 2017 rate year, the separate "GA Rate Riders" line is only applicable to the "Proposed" section of the bill impact tables.
3. 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	1.0489	1.0489	750		N/A	
GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION	kWh	RPP	1.0489	1.0489	2,000		N/A	
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0489	1.0489	52,195	130	DEMAND	
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	Non-RPP (Other)	1.0489	1.0489	3,450		N/A	1
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0489	1.0489	55	1	DEMAND	1
STREET LIGHTING SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0489	1.0489	363,540	1,825	DEMAND	8,070
RESIDENTIAL SERVICE CLASSIFICATION	kWh	Non-RPP (Retailer)	1.0489	1.0481	910		N/A	
GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION	kWh	Non-RPP (Retailer)	1.0489	1.0481	2,000		N/A	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	RPP	1.0489	1.0481	308		N/A	
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 A $	Sub-Total A %	Sub-Total B $	Sub-Total B %	Sub-Total C $	Sub-Total C %	Total A + B + C $
1	RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 6.98	28.4%	$ 3.08	10.9%	$ 3.32	10.0%	$ 1.99
2	GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION - RPP	kWh	$ 14.93	24.0%	$ 4.51	6.4%	$ 5.14	6.2%	$ 1.43
3	GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 192.25	23.1%	$ (34.46)	-4.1%	$ (19.61)	-1.7%	$ (133.51)
4	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - Non-RPP (Other)	kWh	$ 22.04	19.0%	$ 4.44	3.3%	$ 5.53	3.6%	$ (1.12)
5	SENTINEL LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 6.18	21.1%	$ 4.37	14.8%	$ 4.46	14.3%	$ 4.92
6	STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ (13,341.00)	-23.2%	$ (16,626.73)	-28.9%	$ (16,469.60)	-27.2%	$ (19,386.25)
7	RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kWh	$ 6.77	25.8%	$ 2.64	8.3%	$ 2.93	7.8%	$ 1.27
8	GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION - Non-RPP (Retail	kWh	$ 14.93	24.0%	$ 5.73	7.8%	$ 6.35	7.5%	$ 2.70
9	RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 7.55	37.7%	$ 5.80	26.3%	$ 5.90	24.6%	$ 5.58
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Customer Class:	**RESIDENTIAL SERVICE CLASSIFICATION**	
RPP / Non-RPP:	**RPP**	
Consumption	**750**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0489**	
Proposed/Approved Loss Factor	**1.0489**	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 16.79	1	$ 16.79	$ 24.87	1	$ 24.87	$ 8.08	48.12%
Distribution Volumetric Rate	$ 0.0104	750	$ 7.80	$ 0.0088	750	$ 6.60	$ (1.20)	-15.38%
Fixed Rate Riders	$ 0.05	1	$ 0.05	$ (0.08)	1	$ (0.08)	$ (0.13)	-260.00%
Volumetric Rate Riders	-$ 0.0001	750	$ (0.08)	$ 0.0002	750	$ 0.15	$ 0.23	-300.00%
Sub-Total A (excluding pass through)			$ 24.57			$ 31.54	**$ 6.98**	**28.39%**
Line Losses on Cost of Power	$ 0.0822	37	$ 3.01	$ 0.0822	37	$ 3.01	$ -	0.00%
Total Deferral/Variance Account Rate Riders	$ -	750	$ -	-$ 0.0049	750	$ (3.68)	$ (3.68)	
GA Rate Riders	0	750	$ -	$ -	750	$ -	$ -	
Low Voltage Service Charge	$ -	750	$ -		750	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.7900	1	$ 0.79	$ 0.5700	1	$ 0.57	$ (0.22)	-27.85%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 28.37**			**$ 31.45**	**$ 3.08**	**10.86%**
RTSR - Network	$ 0.0059	787	$ 4.64	$ 0.0062	787	$ 4.88	$ 0.24	5.08%
RTSR - Connection and/or Line and Transformation Connection	$ -	787	$ -	$ -	787	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 33.01**			**$ 36.33**	**$ 3.32**	**10.05%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	787	$ 2.83	$ 0.0036	787	$ 2.83	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0021	787	$ 1.65	$ 0.0003	787	$ 0.24	$ (1.42)	-85.71%
Standard Supply Service Charge	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)								
TOU - Off Peak	$ 0.0650	488	$ 31.69	$ 0.0650	488	$ 31.69	$ -	0.00%
TOU - Mid Peak	$ 0.0950	128	$ 12.11	$ 0.0950	128	$ 12.11	$ -	0.00%
TOU - On Peak	$ 0.1320	135	$ 17.82	$ 0.1320	135	$ 17.82	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 99.36**			**$ 101.26**	**$ 1.90**	**1.91%**
HST	13%		$ 12.92	13%		$ 13.16	$ 0.25	1.91%
8% Rebate	8%		$ (7.95)	8%		$ (8.10)	$ (0.15)	
Total Bill on TOU			**$ 104.33**			**$ 106.33**	**$ 1.99**	**1.91%**

Customer Class:	**GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION**	
RPP / Non-RPP:	**RPP**	
Consumption	**2,000**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0489**	
Proposed/Approved Loss Factor	**1.0489**	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 17.11	1	$ 17.11	$ 21.04	1	$ 21.04	$ 3.93	22.97%
Distribution Volumetric Rate	$ 0.0205	2000	$ 41.00	$ 0.0252	2000	$ 50.40	$ 9.40	22.93%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ 0.0020	2000	$ 4.00	$ 0.0028	2000	$ 5.60	$ 1.60	40.00%
Sub-Total A (excluding pass through)			$ 62.11			$ 77.04	**$ 14.93**	**24.04%**
Line Losses on Cost of Power	$ 0.0822	98	$ 8.04	$ 0.0822	98	$ 8.04	$ -	0.00%
Total Deferral/Variance Account Rate Riders	$ -	2,000	$ -	-$ 0.0051	2,000	$ (10.20)	$ (10.20)	
GA Rate Riders	0	2,000	$ -	$ -	2,000	$ -	$ -	
Low Voltage Service Charge	$ -	2,000	$ -		2,000	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.7900	1	$ 0.79	$ 0.5700	1	$ 0.57	$ (0.22)	-27.85%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 70.94**			**$ 75.45**	**$ 4.51**	**6.36%**
RTSR - Network	$ 0.0055	2,098	$ 11.54	$ 0.0058	2,098	$ 12.17	$ 0.63	5.45%
RTSR - Connection and/or Line and Transformation Connection	$ -	2,098	$ -	$ -	2,098	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 82.47**			**$ 87.61**	**$ 5.14**	**6.23%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	2,098	$ 7.55	$ 0.0036	2,098	$ 7.55	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0021	2,098	$ 4.41	$ 0.0003	2,098	$ 0.63	$ (3.78)	-85.71%
Standard Supply Service Charge	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	$ 0.0070	2,000	$ 14.00	$ 0.0070	2,000	$ 14.00	$ -	0.00%
TOU - Off Peak	$ 0.0650	1,300	$ 84.50	$ 0.0650	1,300	$ 84.50	$ -	0.00%
TOU - Mid Peak	$ 0.0950	340	$ 32.30	$ 0.0950	340	$ 32.30	$ -	0.00%
TOU - On Peak	$ 0.1320	360	$ 47.52	$ 0.1320	360	$ 47.52	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 273.00**			**$ 274.36**	**$ 1.36**	**0.50%**
HST	13%		$ 35.49	13%		$ 35.67	$ 0.18	0.50%
8% Rebate	8%		$ (21.84)	8%		$ (21.95)	$ (0.11)	
Total Bill on TOU			**$ 286.65**			**$ 288.08**	**$ 1.43**	**0.50%**

Customer Class:	**GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION**	
RPP / Non-RPP:	**Non-RPP (Other)**	
Consumption	**52,195**	**kWh**
Demand	**130**	**kW**
Current Loss Factor	**1.0489**	
Proposed/Approved Loss Factor	**1.0489**	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 114.46	1	$ 114.46	$ 140.76	1	$ 140.76	$ 26.30	22.98%
Distribution Volumetric Rate	$ 5.4372	130	$ 706.84	$ 6.6563	130	$ 865.32	$ 158.48	22.42%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ 0.0781	130	$ 10.15	$ 0.1355	130	$ 17.62	$ 7.46	73.50%
Sub-Total A (excluding pass through)			$ 831.45			$ 1,023.69	**$ 192.25**	**23.12%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ -	130	$ -	-$ 2.0249	130	$ (263.24)	$ (263.24)	
GA Rate Riders	0	52,195	$ -	$ 0.0007	52,195	$ 36.54	$ 36.54	
Low Voltage Service Charge	$ -	130	$ -		130	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 831.45**			**$ 796.99**	**$ (34.46)**	**-4.14%**
RTSR - Network	$ 2.2455	130	$ 291.92	$ 2.3597	130	$ 306.76	$ 14.85	5.09%
RTSR - Connection and/or Line and Transformation Connection	$ -	130	$ -	$ -	130	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 1,123.36**			**$ 1,103.75**	**$ (19.61)**	**-1.75%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	54,747	$ 197.09	$ 0.0036	54,747	$ 197.09	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0021	54,747	$ 114.97	$ 0.0003	54,747	$ 16.42	$ (98.55)	-85.71%
Standard Supply Service Charge								
Debt Retirement Charge (DRC)	$ 0.0070	52,195	$ 365.37	$ 0.0070	52,195	$ 365.37	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1101	54,747	$ 6,027.68	$ 0.1101	54,747	$ 6,027.68	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 7,828.47**			**$ 7,710.32**	**$ (118.15)**	**-1.51%**
HST	13%		$ 1,017.70	13%		$ 1,002.34	$ (15.36)	-1.51%
Total Bill on Average IESO Wholesale Market Price			**$ 8,846.17**			**$ 8,712.66**	**$ (133.51)**	**-1.51%**

Customer Class:	**UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION**	
RPP / Non-RPP:	**Non-RPP (Other)**	
Consumption	**3,450**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0489**	
Proposed/Approved Loss Factor	**1.0489**	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 12.69	1	$ 12.69	$ 15.06	1	$ 15.06	$ 2.37	18.68%
Distribution Volumetric Rate	$ 0.0310	3450	$ 106.95	$ 0.0368	3450	$ 126.96	$ 20.01	18.71%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	-$ 0.0011	3450	$ (3.80)	-$ 0.0012	3450	$ (4.14)	$ (0.35)	9.09%
Sub-Total A (excluding pass through)			$ 115.85			$ 137.88	**$ 22.04**	**19.02%**
Line Losses on Cost of Power	$ 0.1101	169	$ 18.57	$ 0.1101	169	$ 18.57	$ -	0.00%
Total Deferral/Variance Account Rate Riders	$ -	3,450	$ -	-$ 0.0051	3,450	$ (17.60)	$ (17.60)	
GA Rate Riders	0	3,450	$ -	$ -	3,450	$ -	$ -	
Low Voltage Service Charge	$ -	3,450	$ -		3,450	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 134.42**			**$ 138.86**	**$ 4.44**	**3.30%**
RTSR - Network	$ 0.0055	3,619	$ 19.90	$ 0.0058	3,619	$ 20.99	$ 1.09	5.45%
RTSR - Connection and/or Line and Transformation Connection	$ -	3,619	$ -	$ -	3,619	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 154.32**			**$ 159.85**	**$ 5.53**	**3.58%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	3,619	$ 13.03	$ 0.0036	3,619	$ 13.03	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0021	3,619	$ 7.60	$ 0.0003	3,619	$ 1.09	$ (6.51)	-85.71%
Standard Supply Service Charge								
Debt Retirement Charge (DRC)	$ 0.0070	3,450	$ 24.15	$ 0.0070	3,450	$ 24.15	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1101	3,450	$ 379.85	$ 0.1101	3,450	$ 379.85	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 578.94**			**$ 577.96**	**$ (0.99)**	**-0.17%**
HST	13%		$ 75.26	13%		$ 75.13	$ (0.13)	-0.17%
Total Bill on Average IESO Wholesale Market Price			**$ 654.21**			**$ 653.09**	**$ (1.12)**	**-0.17%**

Customer Class:	**SENTINEL LIGHTING SERVICE CLASSIFICATION**	
RPP / Non-RPP:	**Non-RPP (Other)**	
Consumption	**55**	**kWh**
Demand	**1**	**kW**
Current Loss Factor	**1.0489**	
Proposed/Approved Loss Factor	**1.0489**	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 2.93	1	$ 2.93	$ 3.60	1	$ 3.60	$ 0.67	22.87%
Distribution Volumetric Rate	$ 27.3551	1	$ 27.36	$ 33.6416	1	$ 33.64	$ 6.29	22.98%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	-$ 0.9956	1	$ (1.00)	-$ 1.7711	1	$ (1.77)	$ (0.78)	77.89%
Sub-Total A (excluding pass through)			$ 29.29			$ 35.47	**$ 6.18**	**21.10%**
Line Losses on Cost of Power	$ 0.1101	3	$ 0.30	$ 0.1101	3	$ 0.30	$ -	0.00%
Total Deferral/Variance Account Rate Riders	$ -	1	$ -	-$ 1.8088	1	$ (1.81)	$ (1.81)	
GA Rate Riders	0	55	$ -	$ -	55	$ -	$ -	
Low Voltage Service Charge	$ -	1	$ -		1	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 29.59**			**$ 33.96**	**$ 4.37**	**14.78%**
RTSR - Network	$ 1.7021	1	$ 1.70	$ 1.7887	1	$ 1.79	$ 0.09	5.09%
RTSR - Connection and/or Line and Transformation Connection	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 31.29**			**$ 35.75**	**$ 4.46**	**14.25%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	58	$ 0.21	$ 0.0036	58	$ 0.21	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0021	58	$ 0.12	$ 0.0003	58	$ 0.02	$ (0.10)	-85.71%
Standard Supply Service Charge								
Debt Retirement Charge (DRC)	$ 0.0070	55	$ 0.39	$ 0.0070	55	$ 0.39	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1101	55	$ 6.06	$ 0.1101	55	$ 6.06	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 38.06**			**$ 42.41**	**$ 4.35**	**11.44%**
HST	13%		$ 4.95	13%		$ 5.51	$ 0.57	11.44%
Total Bill on Average IESO Wholesale Market Price			**$ 43.00**			**$ 47.93**	**$ 4.92**	**11.44%**

Customer Class:	**STREET LIGHTING SERVICE CLASSIFICATION**	
RPP / Non-RPP:	**Non-RPP (Other)**	
Consumption	**363,540**	**kWh**
Demand	**1,825**	**kW**
Current Loss Factor	**1.0489**	
Proposed/Approved Loss Factor	**1.0489**	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 2.94	8070	$ 23,725.80	$ 1.42	8070	$ 11,459.40	$ (12,266.40)	-51.70%
Distribution Volumetric Rate	$ 19.1736	1825	$ 34,991.82	$ 9.2724	1825	$ 16,922.13	$ (18,069.69)	-51.64%
Fixed Rate Riders	$ -	8070	$ -	$ -	8070	$ -	$ -	
Volumetric Rate Riders	-$ 0.6353	1825	$ (1,159.42)	$ 8.6771	1825	$ 15,835.67	$ 16,995.09	-1465.82%
Sub-Total A (excluding pass through)			$ 57,558.20			$ 44,217.20	**$ (13,341.00)**	**-23.18%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ -	1,825	$ -	-$ 1.8004	1,825	$ (3,285.73)	$ (3,285.73)	
GA Rate Riders	0	363,540	$ -	$ -	363,540	$ -	$ -	
Low Voltage Service Charge	$ -	1,825	$ -		1,825	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 57,558.20**			**$ 40,931.47**	**$ (16,626.73)**	**-28.89%**
RTSR - Network	$ 1.6935	1,825	$ 3,090.64	$ 1.7796	1,825	$ 3,247.77	$ 157.13	5.08%
RTSR - Connection and/or Line and Transformation Connection	$ -	1,825	$ -	$ -	1,825	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 60,648.84**			**$ 44,179.24**	**$ (16,469.60)**	**-27.16%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	381,317	$ 1,372.74	$ 0.0036	381,317	$ 1,372.74	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0021	381,317	$ 800.77	$ 0.0003	381,317	$ 114.40	$ (686.37)	-85.71%
Standard Supply Service Charge								
Debt Retirement Charge (DRC)	$ 0.0070	363,540	$ 2,544.78	$ 0.0070	363,540	$ 2,544.78	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1101	381,317	$ 41,983.01	$ 0.1101	381,317	$ 41,983.01	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 107,350.14**			**$ 90,194.17**	**$ (17,155.97)**	**-15.98%**
HST	13%		$ 13,955.52	13%		$ 11,725.24	$ (2,230.28)	-15.98%
Total Bill on Average IESO Wholesale Market Price			**$ 121,305.65**			**$ 101,919.41**	**$ (19,386.25)**	**-15.98%**

Customer Class:	**RESIDENTIAL SERVICE CLASSIFICATION**	
RPP / Non-RPP:	**Non-RPP (Retailer)**	
Consumption	**910**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0489**	
Proposed/Approved Loss Factor	**1.0481**	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 16.79	1	$ 16.79	$ 24.87	1	$ 24.87	$ 8.08	48.12%
Distribution Volumetric Rate	$ 0.0104	910	$ 9.46	$ 0.0088	910	$ 8.01	$ (1.46)	-15.38%
Fixed Rate Riders	$ 0.05	1	$ 0.05	$ (0.08)	1	$ (0.08)	$ (0.13)	-260.00%
Volumetric Rate Riders	-$ 0.0001	910	$ (0.09)	$ 0.0002	910	$ 0.18	$ 0.27	-300.00%
Sub-Total A (excluding pass through)			$ 26.21			$ 32.98	**$ 6.77**	**25.82%**
Line Losses on Cost of Power	$ 0.1101	44	$ 4.90	$ 0.1101	44	$ 4.82	$ (0.08)	-1.64%
Total Deferral/Variance Account Rate Riders	$ -	910	$ -	-$ 0.0049	910	$ (4.46)	$ (4.46)	
GA Rate Riders	0	910	$ -	$ 0.0007	910	$ 0.64	$ 0.64	
Low Voltage Service Charge	$ -	910	$ -		910	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.7900	1	$ 0.79	$ 0.5700	1	$ 0.57	$ (0.22)	-27.85%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 31.90**			**$ 34.55**	**$ 2.64**	**8.29%**
RTSR - Network	$ 0.0059	954	$ 5.63	$ 0.0062	954	$ 5.91	$ 0.28	5.00%
RTSR - Connection and/or Line and Transformation Connection	$ -	954	$ -	$ -	954	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 37.53**			**$ 40.46**	**$ 2.93**	**7.80%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	954	$ 3.44	$ 0.0036	954	$ 3.43	$ (0.00)	-0.08%
Rural and Remote Rate Protection (RRRP)	$ 0.0021	954	$ 2.00	$ 0.0003	954	$ 0.29	$ (1.72)	-85.73%
Standard Supply Service Charge								
Debt Retirement Charge (DRC)								
Non-RPP Retailer Avg. Price	$ 0.1101	910	$ 100.19	$ 0.1101	910	$ 100.19	$ -	0.00%
Total Bill on Non-RPP Avg. Price			**$ 143.17**			**$ 144.37**	**$ 1.21**	**0.84%**
HST	13%		$ 18.61	13%		$ 18.77	$ 0.16	0.84%
8% Rebate	8%		$ (11.45)	8%		$ (11.55)		
Total Bill on Non-RPP Avg. Price			**$ 150.32**			**$ 151.59**	**$ 1.27**	**0.84%**

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	**1.0489**	
Proposed/Approved Loss Factor	**1.0481**	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 17.11	1	$ 17.11	$ 21.04	1	$ 21.04	$ 3.93	22.97%
Distribution Volumetric Rate	$ 0.0205	2000	$ 41.00	$ 0.0252	2000	$ 50.40	$ 9.40	22.93%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ 0.0020	2000	$ 4.00	$ 0.0028	2000	$ 5.60	$ 1.60	40.00%
Sub-Total A (excluding pass through)			$ 62.11			$ 77.04	**$ 14.93**	**24.04%**
Line Losses on Cost of Power	$ 0.1101	98	$ 10.77	$ 0.1101	96	$ 10.59	$ (0.18)	-1.64%
Total Deferral/Variance Account Rate Riders	$ -	2,000	$ -	-$ 0.0051	2,000	$ (10.20)	$ (10.20)	
GA Rate Riders	0	2,000	$ -	$ 0.0007	2,000	$ 1.40	$ 1.40	
Low Voltage Service Charge	$ -	2,000	$ -		2,000	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.7900	1	$ 0.79	$ 0.5700	1	$ 0.57	$ (0.22)	-27.85%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 73.67**			**$ 79.40**	**$ 5.73**	**7.78%**
RTSR - Network	$ 0.0055	2,098	$ 11.54	$ 0.0058	2,096	$ 12.16	$ 0.62	5.37%
RTSR - Connection and/or Line and Transformation Connection	$ -	2,098	$ -	$ -	2,096	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 85.21**			**$ 91.56**	**$ 6.35**	**7.46%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	2,098	$ 7.55	$ 0.0036	2,096	$ 7.55	$ (0.01)	-0.08%
Rural and Remote Rate Protection (RRRP)	$ 0.0021	2,098	$ 4.41	$ 0.0003	2,096	$ 0.63	$ (3.78)	-85.73%
Standard Supply Service Charge								
Debt Retirement Charge (DRC)	$ 0.0070	2,000	$ 14.00	$ 0.0070	2,000	$ 14.00	$ -	0.00%
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			**$ 331.36**			**$ 333.93**	**$ 2.57**	**0.78%**
HST	13%		$ 43.08	13%		$ 43.41	$ 0.33	0.78%
8% Rebate	8%		$ (26.51)	8%		$ (26.71)		
Total Bill on Non-RPP Avg. Price			**$ 347.93**			**$ 350.63**	**$ 2.70**	**0.78%**

Customer Class:	**RESIDENTIAL SERVICE CLASSIFICATION**	
RPP / Non-RPP:	**RPP**	
Consumption	**308**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0489**	
Proposed/Approved Loss Factor	**1.0481**	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 16.79	1	$ 16.79	$ 24.87	1	$ 24.87	$ 8.08	48.12%
Distribution Volumetric Rate	$ 0.0104	308	$ 3.20	$ 0.0088	308	$ 2.71	$ (0.49)	-15.38%
Fixed Rate Riders	$ 0.05	1	$ 0.05	$ (0.08)	1	$ (0.08)	$ (0.13)	-260.00%
Volumetric Rate Riders	-$ 0.0001	308	$ (0.03)	$ 0.0002	308	$ 0.06	$ 0.09	-300.00%
Sub-Total A (excluding pass through)			$ 20.01			$ 27.56	**$ 7.55**	**37.72%**
Line Losses on Cost of Power	$ 0.0822	15	$ 1.24	$ 0.0822	15	$ 1.22	$ (0.02)	-1.64%
Total Deferral/Variance Account Rate Riders	$ -	308	$ -	-$ 0.0049	308	$ (1.51)	$ (1.51)	
GA Rate Riders	0	308	$ -	$ -	308	$ -	$ -	
Low Voltage Service Charge	$ -	308	$ -		308	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.7900	1	$ 0.79	$ 0.5700	1	$ 0.57	$ (0.22)	-27.85%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 22.04**			**$ 27.84**	**$ 5.80**	**26.32%**
RTSR - Network	$ 0.0059	323	$ 1.91	$ 0.0062	323	$ 2.00	$ 0.10	5.00%
RTSR - Connection and/or Line and Transformation Connection	$ -	323	$ -	$ -	323	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 23.95**			**$ 29.84**	**$ 5.90**	**24.62%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	323	$ 1.16	$ 0.0036	323	$ 1.16	$ (0.00)	-0.08%
Rural and Remote Rate Protection (RRRP)	$ 0.0021	323	$ 0.68	$ 0.0003	323	$ 0.10	$ (0.58)	-85.73%
Standard Supply Service Charge	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)								
TOU - Off Peak	$ 0.0650	200	$ 13.01	$ 0.0650	200	$ 13.01	$ -	0.00%
TOU - Mid Peak	$ 0.0950	52	$ 4.97	$ 0.0950	52	$ 4.97	$ -	0.00%
TOU - On Peak	$ 0.1320	55	$ 7.32	$ 0.1320	55	$ 7.32	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 51.34**			**$ 56.66**	**$ 5.31**	**10.35%**
HST	13%		$ 6.67	13%		$ 7.37	$ 0.69	10.35%
8% Rebate	8%		$ (4.11)	8%		$ (4.53)	$ (0.43)	
Total Bill on TOU			**$ 53.91**			**$ 59.49**	**$ 5.58**	**10.35%**

%
1.9%
0.5%
-1.5%
-0.2%
11.4%
-16.0%
0.8%
0.8%
10.3%

APPENDIX 4

2016 Scorecard – PUC Distribution Inc.

Scorecard - PUC Distribution Inc.

9/11/2017

Performance Outcomes	Performance Categories	Measures		2012	2013	2014	2015	2016	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		95.80%	96.50%	93.00%	97.20%	98.90%	↑	90.00%	
		Scheduled Appointments Met On Time		98.40%	97.10%	95.40%	97.40%	98.30%	↑	90.00%	
		Telephone Calls Answered On Time		74.60%	80.90%	81.90%	82.30%	81.30%	↑	65.00%	
	Customer Satisfaction	First Contact Resolution				99.89%	99.92%	99.58%			
		Billing Accuracy				99.83%	99.36%	99.97%	↑	98.00%	
		Customer Satisfaction Survey Results				In progess	79%	80%			
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					86.00%	86.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		NI	C	C	C	C	→		C
		Serious Electrical Incident Index	Number of General Public Incidents	3	1	3	1	0	↓		1
			Rate per 10, 100, 1000 km of line	0.407	0.135	0.405	0.134	0.000	→		0.151
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		1.65	1.42	1.19	1.37	1.49	↓		1.86
		Average Number of Times that Power to a Customer is Interrupted [2]		2.17	1.78	1.21	1.03	1.41	↓		2.32
	Asset Management	Distribution System Plan Implementation Progress				In progress	In Progress	In progress			
	Cost Control	Efficiency Assessment		3	4	4	4	4			
		Total Cost per Customer [3]		$615	$687	$664	$699	$695			
		Total Cost per Km of Line [3]		$27,523	$30,950	$29,886	$31,377	$31,314			
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]					17.18%	52.97%			26.41 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time					0.00%	100.00%			
		New Micro-embedded Generation Facilities Connected On Time			100.00%	100.00%	100.00%		→	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.19	1.06	1.68	0.90	1.52			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		2.01	1.99	2.42	2.31	2.34			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	8.57%	8.98%	8.98%	8.98%	8.98%			
			Achieved	4.99%	7.00%	5.47%	4.46%	0.98%			

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 fixed 5-year (2010 to 2014) average 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

Appendix A – 2016 Scorecard Management Discussion and Analysis ("2016 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 2016 Scorecard MD&A:
http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf

Scorecard MD&A - General Overview

In 2016 PUC Distribution Inc. (PUC) met or exceeded all prescribed targets for scorecard measures. PUC continued with strong performance in the Customer Focus, Operational Effectiveness and Public Policy Responsiveness areas of our scorecard. This has generally been reflected in good customer satisfaction survey measure results.

Service Quality

- **New Residential/Small Business Services Connected on Time**
  In 2016, PUC Distribution connected 349 eligible low-voltage residential and small business customers (connections under 750 volts) to its distribution system, 98.90% of which were connected within the five-day timeline prescribed by the Ontario Energy Board (OEB). This is a 1.7% increase from the previous year and exceeds the OEB mandated target of 90%. The improved performance over 2015 can be partly attributed to a reduction in capital works projects which allowed additional resources to focus on low volume connections. PUC Distribution has demonstrated our commitment to continuous improvement through staff education to ensure customer satisfaction is a top priority.

- **Scheduled Appointments Met On Time**
  In 2016, PUC Distribution scheduled 1,468 appointments with customers to complete customer requested work (e.g. meter installs/removals, service disconnects/reconnects, and meter locates). As a result of our emphasis on customer satisfaction, PUC was able to meet 98.30% of scheduled appointments on time, which exceeds the OEB target of 90%.

- **Telephone Calls Answered On Time**
  In 2016, PUC Distribution's Customer Care Department received 40,787 calls from its customers. This represents an increase in call volume of approximately 1,900 calls from 2015, due in part, to the utility switching to automated reminder calls for past due accounts.

Of the 40,787 calls, a Customer Care Representative answered the call within 30 seconds or less, 81.30% of the time. This result significantly exceeds the OEB mandated 65% target for timely call response.

Customer Satisfaction

- **First Contact Resolution**

  PUC Distribution's First Contact Resolution was measured by tracking the number of electric related calls which were escalated to a Senior Customer Care Representative or Supervisor/Manager. This was accomplished by creating two specific call types in our Customer Information System (CIS) which would then be queried to provide the number of customer concerns which were escalated.

  In 2016, PUC had 40,787 calls, of which, 171 contacts were escalated to a higher level of management. This resulted in a First Contact Resolution percentage of 99.58%.

  To establish the number of calls which were handled without escalation, the total number of calls which were escalated to a higher level of management was subtracted from the total number of calls received. However, it should be noted that First Contact Resolution can be measured in a variety of ways and further regulatory guidance is necessary in order to achieve meaningful comparable information across electricity distributors.

- **Billing Accuracy**

  PUC issued approximately 395,000 bills for the period from January 1, 2016 – December 31, 2016, and achieved an accuracy of 99.97%. This score compares favourably to the prescribed OEB target of 98%. PUC continues to monitor its billing accuracy results and processes to identify opportunities for improvement.

- **Customer Satisfaction Survey Results**

  PUC Distribution engaged the UtilityPulse Division of Simul Corporation to conduct our 2016 customer satisfaction survey. The UtilityPulse Electric Utility Survey is in its 19th year of annual surveys and is used by a significant number of Ontario distributors. The final report on our customer satisfaction survey was received in March 2017, and PUC Distribution received a B+ customer satisfaction score of 80% (post survey result) which is above the Ontario benchmark survey that had a grade of "B".

  The raw score had a slight increase from our last survey of 79%. The survey asked customers questions on a broad range of topics, including overall satisfaction with reliability, customer service, outages, billing and corporate image. These customer satisfaction surveys

are an important element in our overall customer engagement strategy providing further insight towards planning and supporting customer service improvement at all levels within PUC Distribution.

Public Safety

The Public Safety measure was introduced by the OEB in 2015 and focuses on the safety of the distribution system from a customer's point of view. The Electrical Safety Authority (ESA) provides an assessment as it pertains to Component B – Compliance with Ontario Regulation 22/04 and Component C – Serious Electrical Incident Index.

- **Component A – Public Awareness of Electrical Safety.**

  A representative sample of PUC Distribution's service territory population was surveyed in late 2015 to gauge the public's awareness level of key electrical safety concepts related to distribution assets. The purpose of the survey was to provide a benchmark level concerning the public's electrical safety awareness, and identify opportunities where additional education and outreach may be required. The results of the survey were analyzed in 2016, a number of opportunities to improve our existing outreach programs were identified and an action plan was developed.

  One item of note from the survey results indicated that more emphasis was required to ensure public awareness of Ontario One Call. In an effort to improve this metric, PUC approved a budget in 2016 (for 2017) to purchase promotional Dig Safe decals for the entire operations fleet, and through participation with the Association of Electrical Utility Professionals (AEUSP) has contributed to the production of a series of Electricity Safety videos for television broadcast in our service area. (Expected for 2017)

  PUC Distribution continues to look for every opportunity to communicate and engage with the public to promote electrical safety awareness in our service area. Below are examples of PUC Distribution's public safety communication initiatives in 2016:

  - Elementary School Electrical Safety Program for Grade 3 – 5 within our geographic service territory. Participation included 24 schools. (73 classes, and 1,874 students)
  - Advanced Research & Technology Innovation Expo (ARTIE) (approx. 360 students and their teachers participated)
  - Sault Ste. Marie Science Festival (approx. 500 adults and children attended)
  - Sault Ste. Marie PUC website – Safety tab with particular activities aimed at educating young people on electrical safety
  - Advertisements in the geographic service territory consists of newspaper and radio ads

- **Component B – Compliance with Ontario Regulation 22/04**

  Ontario Regulation 22/04 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, and specifications and the inspection of construction to ensure there are no undue hazards before they are put in service.

  Component B is comprised of an External Audit, a Declaration of Compliance, Due Diligence Inspections, Public Safety Concerns, and Compliance Investigations. ESA evaluates all these elements as a whole to determine the status of compliance. In each of the past four years, PUC Distribution was found to be compliant with Ontario Regulation 22/04 (Electrical Distribution Safety). PUC attributes this continued success to our strong commitment to safety, and adherence to company policies and procedures.

- **Component C – Serious Electrical Incident Index**

  Section 12 of Ontario Regulation 22/04 specifies the requirement to report to ESA any serious electrical incident of which they become aware within 48 hours after the occurrence. For the 2016 reporting period, PUC Distribution did not experience any serious electrical incidents.

  To increase public safety awareness, PUC Distribution offers electrical safety awareness outreach via; newspapers, radio, public events, presentations to elementary school students, and detailed hazard awareness presentations to contractors.

System Reliability

A key change for 2016, as required by the OEB, is the revised reporting of reliability data with respect to Major Events. Specifically the change serves to adjust the reliability data to remove the impact of Major Events. Additionally, distributors are required to report criteria to monitor the distributor's performance related to the Major Event.

The 2016 Scorecard system reliability data, excludes both Loss of Supply and Major Events. The adjusted reliability measures capture interruptions caused by circumstances within the distributor's control and are published in the 2016 scorecard.

A "Major Event" is defined as an event that is beyond the control of the distributor and is; unforeseeable, unpredictable, unpreventable, or unavoidable. Such events disrupt normal business operations and occur so infrequently that it would be uneconomical to take them into account when designing and operating the distribution system. Such events cause exceptional and/or extensive damage to assets,

take significantly longer than usual to repair, and affect a substantial number of customers.

In 2016 there were two major event days. The first happened on March 6 (foreign interference) and the second on June 20 (adverse weather).

- **Average Number of Hours that Power to a Customer is Interrupted**
  The System Average Interruption Duration Index (SAIDI) of 1.49 in 2016 was below the target of 1.86. There are ongoing efforts to improve reliability including replacing aging infrastructure and improving vegetation management.

- **Average Number of Times that Power to a Customer is Interrupted**
  The System Average Interruption Frequency Index (SAIFI) of 1.41 in 2016 was substantially below the target of 2.32. Consistent with SAIDI, there are ongoing efforts to improve reliability including replacing aging infrastructure and improving vegetation management.

Asset Management

- **Distribution System Plan Implementation Progress**
  Although PUC has employed distribution system planning for several years, the OEB instituted a mandatory requirement for this activity to be practised provincially, along with associated performance measures, beginning in 2013. We expect that implementation of this standardised approach will allow us to strengthen our commitment to responsible long term planning and sustainable asset management and to align our objectives with those of the of the OEB ultimately maximising benefit to our ratepayers.

  All distributors are required to file a Distribution System Plan (DSP) when filing a cost of service application for the rebasing of their rates. PUC is presently engaged in migrating and expanding upon its existing distribution system planning to create a formal DSP that meets all OEB requirements. The new DSP will be accompanied by performance measures and once completed will be filed with PUC's next OEB rate application to be filed in 2017.

Cost Control

- **Efficiency Assessment**

The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC (PEG) on behalf of the OEB to produce a single efficiency ranking. The PEG econometrics model attempts to standardize costs to facilitate more accurate cost comparisons among distributors by accounting for differences such as number of customers, treatment of high and low voltage costs, kWh deliveries, capacity, customer growth, length of lines, etc. All Ontario electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual costs versus the PEG model predicted costs. The following table summarizes the distribution of all distributors across the 5 groupings for 2016:

Group	Demarcation Points for Relative Cost Performance	Group Ranking	# of Ontario LDCs in Group
1	Actual costs are 25% or more below predicted costs	Most Efficient	6
2	Actual costs are 10% to 25% below predicted costs	More Efficient	14
3	Actual costs are within +/-10% of predicted costs	Average Efficiency	32
4	Actual costs are 10% to 25% above predicted costs	Less Efficient	13
5	Actual costs are 25% or more above predicted costs	Least Efficient	3

In 2016, for the fourth year in a row, PUC Distribution was placed in Group 4. PUC Distribution's efficiency performance based on the PEG model was over the predicted costs by 14% in 2016 compared to 16.2% in 2015.

- **Total Cost per Customer**

Total cost per customer is calculated as the sum of PUC Distribution's capital and operating costs, including certain adjustments to make the costs more comparable between distributors (i.e. under the PEG econometrics model), and dividing this cost figure by the total number of customers that PUC Distribution serves.

The cost performance result for 2016 is $695 per customer which is a 0.57 % decrease over 2015. Overall, the company's Total Cost per Customer has increased on average by 3.26% per annum over the period 2012 through 2016. For the period of 2013 to 2016, the Total Cost per Customer has increased by approximately 0.40% per year.

PUC Distribution will continue to replace aging distribution assets proactively in a manner that balances system risks and customer rate impacts. PUC Distribution's capital and operating programs will be further defined in its 2018 rate application to be filed in 2017. The

company continues to implement productivity and improvement initiatives to help offset some of the costs associated with future system improvement and enhancements. Customer engagement initiatives that commenced in 2016 will continue in order to ensure customers have an opportunity to share their viewpoint on PUC Distribution'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 the company operates to serve its customers. PUC Distribution's 2016 rate is $31,314 per Km of line, a 0.20% decrease over 2015.

  PUC Distribution continues to experience a low level of growth in its total kilometers of lines due to a low annual customer growth rate. Such a low growth rate has reduced the ability to fund capital renewal and increasing operating costs through customer growth. As a result, total cost per Km of line has increased an average of 3.45% since 2012 with the increase in capital and operating costs. For the period of 2013 to 2016, the Total Cost per Km of Line has increased by approximately 0.40% per year.

Conservation & Demand Management

- **Net Cumulative Energy Savings**
  PUC is committed to helping its customers understand their energy usage by offering programs that enable them to become more energy efficient. PUC has a conservation target of 26.4 Gigawatt hours by the end of 2020. Results for 2016 show progress of 52.97% towards that target. This achievement was made possible by the strong participation by local commercial/industrial customers in retrofit and auditing programs. Residential customers also participated in saveONenergy coupon events opting to replace lights in their homes to more energy efficient ones, as well as purchasing other energy efficient equipment. The combined efforts of participants from both the residential and business sectors made the achievement of substantial energy savings possible.

  Notable projects where city wide street lighting, not only in Sault Ste. Marie but Prince Township and Batchewana First Nations. Municipal parking lots followed suit with upgrading their parking lot lighting to LED, while small businesses began changing their florescent lamps and incandescent bulbs to efficient LED tubes and lamps.

  PUC remains committed to providing its customers with cost effective conservation programs to help them save electricity and lower their electricity bills. PUC will continue to innovate new ways to promote and support customers in reducing their consumption today

and for the future.

As a member of CustomerFirst, PUC is part of a joint Conservation (CDM) Plan that has been approved by the IESO. The joint plan will achieve 141,877 MWh of savings which is equal to the combined targets that were allocated to each CustomerFirst member under the new framework. Through the CustomerFirst joint CDM Plan, PUC will continue to work collaboratively with the other CustomerFirst utilities to find efficiencies and reduce costs. The group will be sharing resources and working together in all areas of CDM including sales, marketing, customer and project support to provide value to ratepayers.

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 for their project from the Electrical Safety Authority. For the year 2016 four CIA requests were received for a total of 820kW of FIT generation, and all applications were processed within the prescribed timelines.

- **New Micro-embedded Generation Facilities Connected On Time**
  In 2016, interest in the micoFIT program was much lower than in previous years. PUC Distribution Inc. received only one application and provided an offer to connect, but no follow-up request for connection was received. Outside of the micoFIT program, one application for a net metering load displacement installation was made.

  PUC's process to connect these projects is very streamlined and transparent for its customers. PUC works closely with customers and contractors to address any connection issues and ensure projects are connected in a timely manner.

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.

  PUC Distribution's current ratio has increased from 0.90 in 2015 to 1.52 in 2016. By increasing over 1, PUC Distribution is in a good

position to cover the company's short-term debts and financial obligations.

- **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.

  PUC Distribution has a debt to equity structure of 70% to 30% that approximates the deemed 60% to 40% capital mix as set out by the OEB – this translates to a 2016 debt to equity ratio of 2.34. PUC Distribution's long range plan is to push the debt to equity towards the 60/40 level.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**
  PUC Distribution's current distribution rates were approved by the OEB and include an expected (deemed) regulatory return on equity of 8.98%. The OEB allows a distributor to earn within +/- 3 percentage points 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**
  PUC Distribution's return on equity in 2016 at 0.98% was more than 3 percentage points lower than the expected return of 8.98%. The variance in return on equity is the result of PUC Distribution's OM&A expenses in 2016 being approximately $1.4 million higher than included in the approved 2013 cost of service rate application. PUC plans on filing a 2018 Cost of Service Rate Application for rates effective in 2018.

Note to Readers

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 judgement on the reporting date of the performance scorecard, and could be markedly different in the future.

APPENDIX 5

Appendix 5 - PUC Distribution Inc Customer Satisfaction Survey

PUC Distribution Inc.





2017 Electric Utility Customer Satisfaction Survey



Electric Utility
Customer Satisfaction Survey



- Based on telephone interviews of *401 respondents* who pay or look after the electricity bills for *PUC Distribution*
- Note: A sample size of 401 will provide confidence level of 95% (+/-4.9%)
- Customers surveyed were based on a *random sample* approach
- 1,553 households and small businesses were contacted, 401 completed interviews; response rate is 26%
- The following *segments* were surveyed:
  - Residential – 85%
  - Commercial – 15%
- PUC Distribution'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.

PUC Distribution had been given excellent scores, on trust, satisfaction, and reliability.







Survey respondents are looking through the lens of costs, more specifically affordability, therefore ratings for 2017 have been impacted.







Operational & Representative Attributes

Operational			
Top 2 Boxes: 'Strongly + Somewhat agree'	PUC Distribution	National	Ontario
Provides consistent, reliable electricity	91%	89%	89%
Quickly handles outages and restores power	90%	87%	85%
Accurate billing	81%	83%	80%

Base: total respondents with an opinion

Representatives			
Top 2 Boxes: 'Strongly + Somewhat agree'	PUC Distribution	National	Ontario
Deals professionally with customers problems	85%	83%	81%
Is 'easy to do business with'	85%	81%	77%
Customer-focused and treats customers as if they're valued	73%	75%	73%

Base: total respondents with an opinion



91%

"Provides consistent, reliable electricity..."

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 PUC Distribution 80%
[Ontario 77%; National 80%]





76%

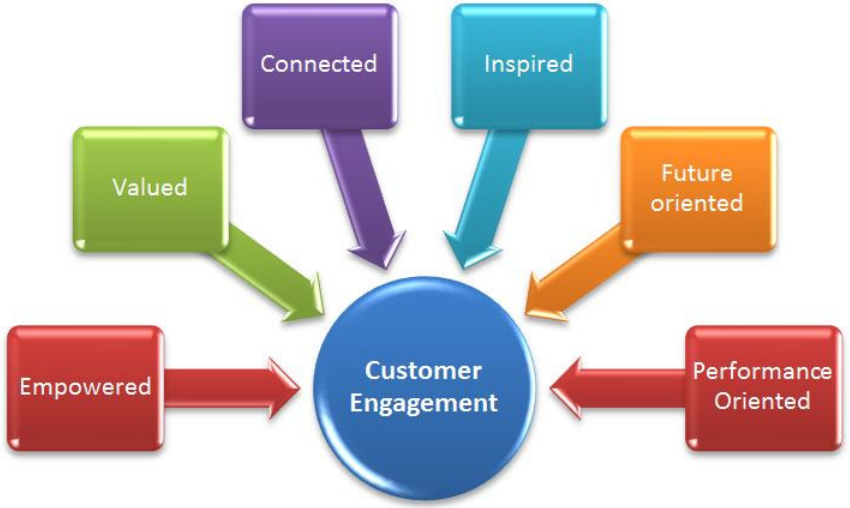
"Keeps its promises to customers and the community..."

Base: total respondents

CCEI: Customer Centric Engagement Index

Customer Centric Engagement Index (CCEI)			
	PUC Distribution	National	Ontario
CCEI	78%	78%	74%

Base: total respondents





78%

"... CCEI: Customer Centric Engagement Index..."

CEPr: Customer Experience Performance rating

Customer Experience Performance rating (CEPr)			
	PUC Distribution	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'?*

Quality of Services

3. *Does the organization effectively meet your needs?*
4. *Does the organization provide high quality services?*



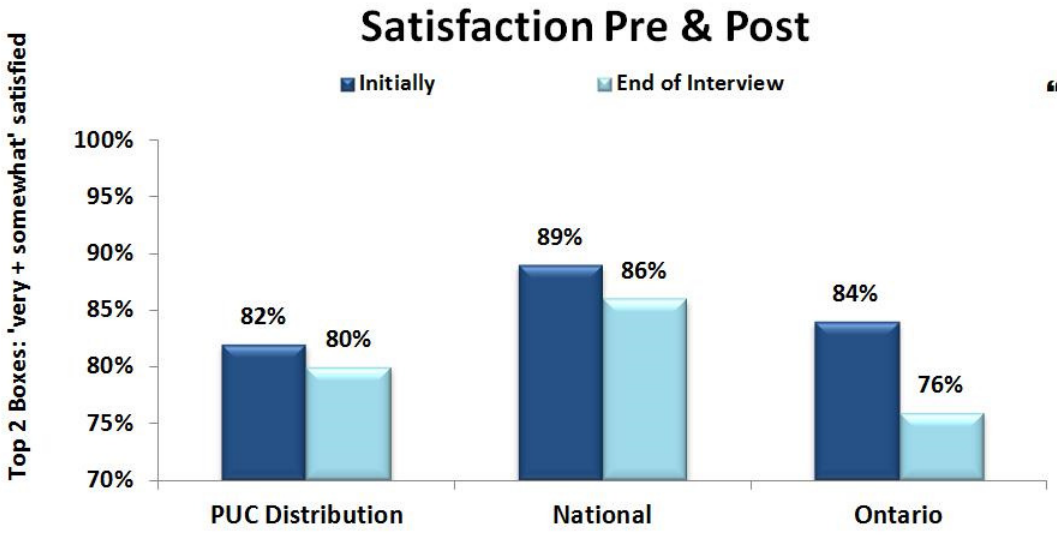
83%

"CEPr: Customer experience rating..."

Customer Satisfaction

Electricity bill payers who are 'very or fairly' satisfied with…			
Top 2 Boxes: 'very + fairly satisfied'	PUC Distribution	National	Ontario
PRE: Initial Satisfaction Scores	82%	89%	84%
POST: End of Interview	80%	86%	76%

Base: total respondents





PRE **82%**

"SATISFIED: Beginning of Interview"



POST **80%**

"SATISFIED: End of Interview"

Base: total respondents

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	86%	83%	74%

Base: total respondents

SATISFACTION SCORES – Electricity customers' satisfaction [Income]			
Top 2 Boxes: 'very + fairly satisfied'	<$30K	$30 – 75K	$75K +
Satisfaction Scores	71%	81%	85%

Base: total respondents

SATISFACTION SCORES – Electricity customers' satisfaction		
Top 2 Boxes: 'very + fairly satisfied'	Residential	Small Commercial
Satisfaction Scores	80%	90%

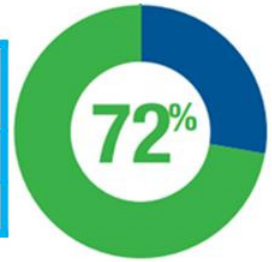
Base: total respondents



Customer Commitment

"Is a company that you would like to continue to do business with"

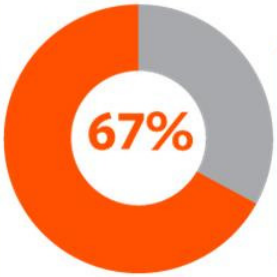
Electricity customers' loyalty – … Is a company that you would like to continue to do business with			
	PUC Distribution	National	Ontario
Top 2 Boxes: 'Definitely + Probably' continue	72%	78%	69%



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			
	PUC Distribution	National	Ontario
Top 2 Boxes: 'Definitely + Probably' recommend	67%	71%	59%

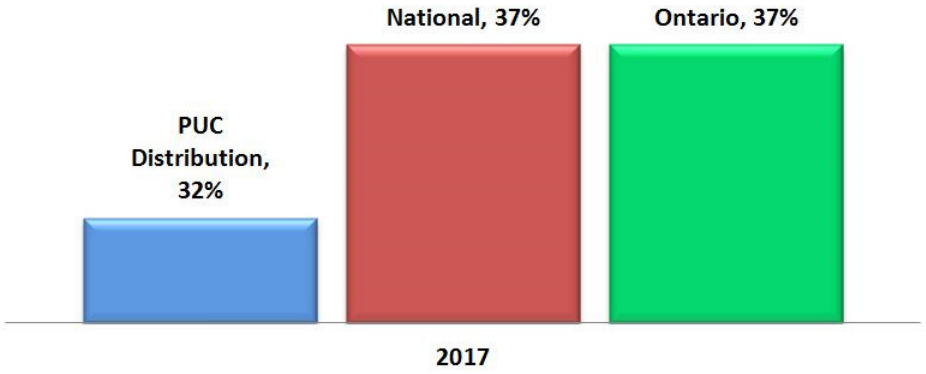
Base: total respondents

Outage Problems (last 12 months)

Percentage of Respondents indicating that they had a Blackout or Outage problem in the last 12 months			
	PUC Distribution	National	Ontario
2017	32%	37%	37%
2016	-	53%	51%
2015	45%	47%	49%
2014	-	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

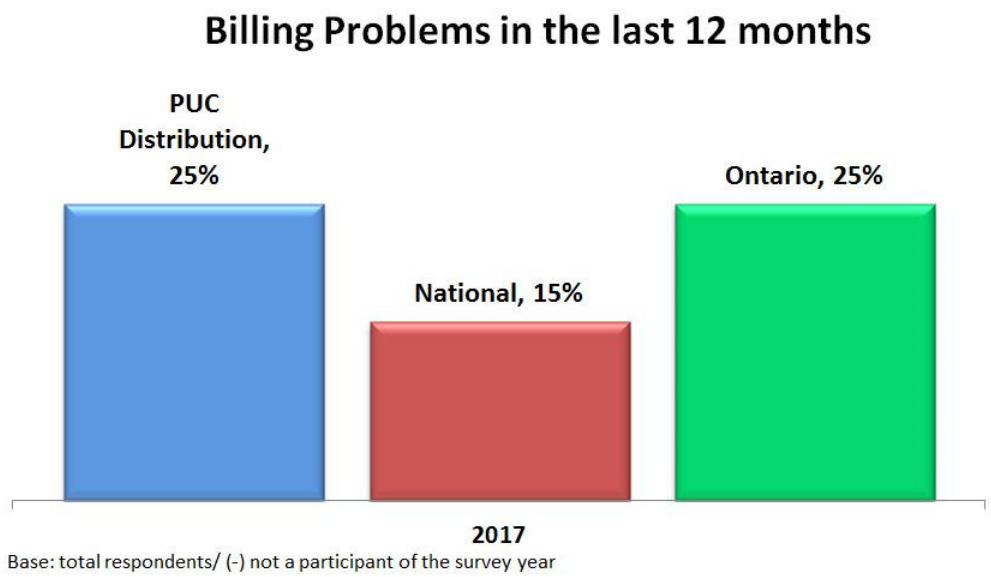


"... Quickly handles outages and restores power..."

Billing Problems (last 12 months)

Percentage of Respondents indicating that they had a Billing problem in the last 12 months			
	PUC Distribution	National	Ontario
2017	25%	15%	25%
2016	-	9%	15%
2015	13%	16%	25%
2014	-	8%	10%
2013	-	12%	13%

Base: total respondents/ (-) not a participant of the survey year



Base: total respondents/ (-) not a participant of the survey year



"... Provides accurate billing..."

Types of billing problems

Types of Billing Problems	
	PUC Distribution
The amount owed was too high	91%
Complaint about rates or charges	10%
The bill was difficult to understand	6%
Too many extra charges	4%
Payment incorrectly recorded	3%
Double payment	2%
The bill arrived late	1%
Wrong information on bill	1%

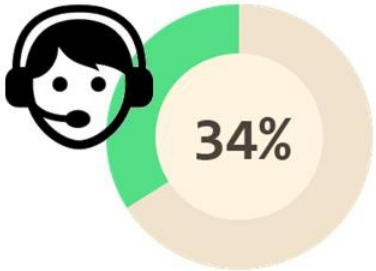
Base: total respondents with billing problems



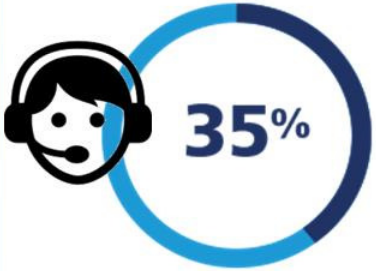


"... Amount owed was too high ..."

Bill Payer's Problems and Problem Resolution



34% of PUC Distribution respondents with an outage problem did contact the utility.



35% of PUC Distribution respondents with a billing problem did contact the utility.

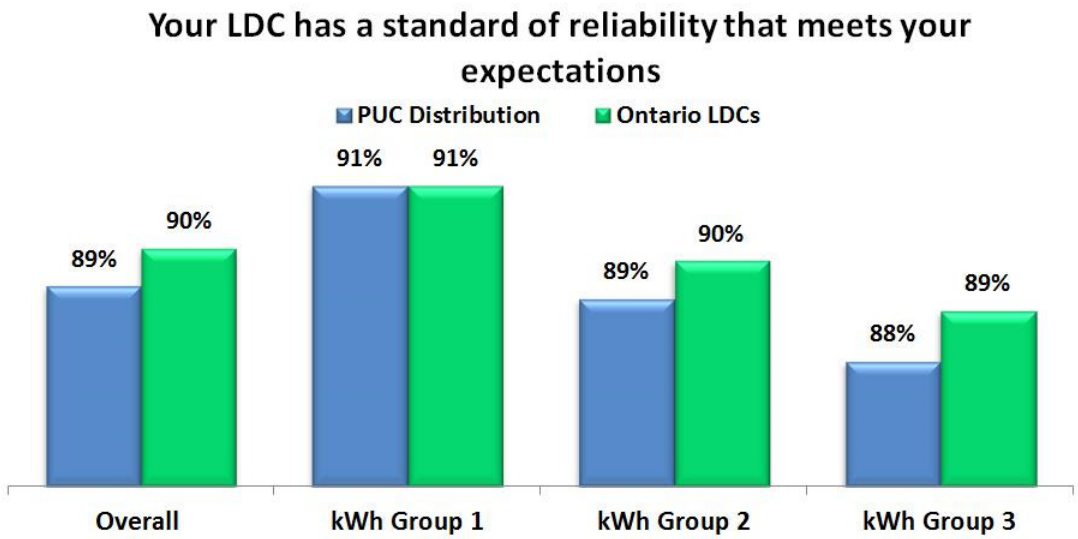


Respondents who said they contacted the utility were also asked "Do you consider the problem solved or not solved?" 46% of your LDC's respondents said their problem was solved.

Reliability Standards:

Your LDC has a standard of reliability that meets your expectations		
	PUC Distribution	Ontario LDCs
Overall	89%	90%
kWh Group 1	91%	91%
kWh Group 2	89%	90%
kWh Group 3	88%	89%

Base: total respondents /UtilityPULSE Database



Base: total respondents /UtilityPULSE Database

Statistically speaking, these numbers are the same.

Emphasis on Outage Management:

Emphasis on Outage Management	
	PUC Distribution
Reduce the number of outages	4%
Reduce the duration of outages	4%
Both	32%
Neither, not willing to pay more	55%
Don't know	4%

Base: total respondents



Some actual quotes:

- *"No I wouldn't pay more, No",*
- *"We pay lots already, don't want to pay more",*
- *"No, I am not willing to pay more. I can't pay more",*
- *"I wouldn't pay more money for either of them. I am paying enough now. They need to find savings in their own company and stop billing the public."*



Emphasis on Outage Management:

Emphasis on Outage Management			
PUC Distribution	Overall	Residential	Small Commercial
Reduce the number of outages	4%	4%	5%
Reduce the duration of outages	4%	4%	3%
Both	32%	32%	32%
Neither, not willing to pay more	55%	55%	57%
Don't know	4%	5%	3%

Base: total respondents

Emphasis on Outage Management			
PUC Distribution	<$30K	$30 – 75K	$75K+
Reduce the number of outages	2%	4%	6%
Reduce the duration of outages	10%	4%	3%
Both	34%	32%	30%
Neither, not willing to pay more	51%	53%	57%
Don't know	2%	6%	4%

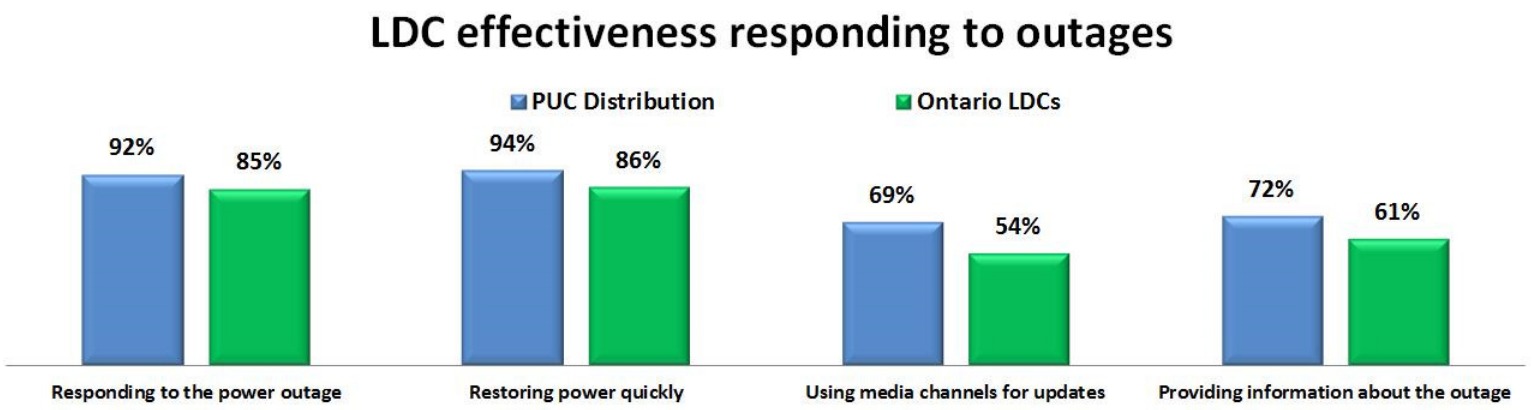
Base: total respondents



Effectiveness Responding to Outages:

92%	94%	69%	72%
• Responding to the power outage	• Restoring power quickly	• Using media channels for updates	• Providing information about the outage

Base: total respondents



Base: total respondents / UtilityPULSE Database

Effectiveness Responding to Outages:

LDC effectiveness responding to outages: Top 2 Boxes: "Very + Somewhat effective"			
PUC Distribution	Overall	Residential	Small Commercial
Responding to the power outage	92%	91%	95%
Restoring power quickly	94%	93%	95%
Using media channels for updates	69%	68%	73%
Providing information about the outage	72%	71%	75%

Base: total respondents

LDC effectiveness responding to outages: Top 2 Boxes: "Very + Somewhat effective"			
PUC Distribution	18-34	35-54	55+
Responding to the power outage	97%	91%	91%
Restoring power quickly	100%	91%	93%
Using media channels for updates	84%	74%	63%
Providing information about the outage	84%	71%	69%

Base: total respondents

Customer Service

Customer Service Expectations	PUC Distribution	National	Ontario
The time it took to contact someone	72%	67%	63%
The time it took someone to deal with your problem	64%	64%	60%
The helpfulness of the staff who dealt with you	71%	67%	64%
The knowledge of the staff who dealt with you	72%	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	63%	65%	64%

Base: total respondents





"Deals professionally with customers' problems..."

Base: total respondents

Recent Experience: Satisfaction

Overall satisfaction with most recent experience			
	PUC Distribution	National	Ontario
Top 2 Boxes: 'very + fairly satisfied'	61%	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.

Customer Service Quality

Customer Service Quality			
	PUC Distribution	National	Ontario
Deals professionally with customers' problems	85%	83%	81%
Customer-focused and treats customers as if they're valued	73%	75%	73%
Is a company that is 'easy to do business with'	85%	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*



"... Customer-focused and treats customers as if they're valued..."

Report Card: B+

PUC Distribution's UtilityPULSE Report Card®			
	Category	PUC Distribution	Ontario
1	**Customer Care**	**B**	**C+**
	Price and Value	C+	C
	Customer Service	B+	B
2	**Company Image**	**B+**	**B**
	Company Leadership	B	B
	Corporate Stewardship	B+	B
3	**Management Operations**	**A**	**A**
	Operational Effectiveness	A	B+
	Power Quality and Reliability	A+	A
	OVERALL	**B+**	**B**

"B ... Customer Care"

"B+ ... Company Image"

"A ... Management Operations"

LDC Attributes

Low scoring			
Top 2 Boxes: 'Strongly + Somewhat agree'	PUC Distribution	National	Ontario
Adapts well to changes in customer expectations	68%	71%	68%
Operates a cost effective electricity system	62%	70%	56%
Provides good value for your money	57%	62%	56%
Cost of electricity is reasonable when compared to other utilities	44%	61%	48%

Base: total respondents with an opinion

High Scoring			
Top 2 Boxes: 'Strongly + Somewhat agree'	PUC Distribution	National	Ontario
Provides consistent, reliable electricity	91%	89%	89%
Makes electricity safety a top priority for employees and contractors	91%	87%	86%
Quickly handles outages and restores power	90%	87%	85%
Has a standard of reliability that meets expectations	89%	88%	86%

Base: total respondents with an opinion



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	39%	34%	46%	39%
Mostly worse	9%	12%	7%	7%
Neither	46%	39%	41%	54%
Don't know	5%	15%	4%	0%

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	39%	50%	44%	36%
Mostly worse	9%	6%	9%	8%
Neither	46%	44%	47%	47%
Don't know	5%	0%	0%	9%

Base: total respondents



39%

"The effect of technological changes on people's lives will lead to a future that is … MOSTLY BETTER"

Use of Technology



83%

- Access the internet for information



55%

- Have a social media account



71%

- Use online banking



53%

- Shop online



71%

"Use online banking"

Base: total respondents

Importance of Online Access

Importance of online access for the following features:		
Top 2 Boxes: 'very + somewhat important'	**PUC Distribution**	**UtilityPULSE Database**
Reporting or inquiring about an issue	53%	71%
Researching information about energy conservation	58%	79%
Having a web chat feature on the website	32%	50%
Automated alerts when electricity usage exceeds a prearranged threshold	54%	71%
Review and pay your bill online (through utility's website)	53%	68%
Power outage alerts	61%	80%
Tools and calculators to help you manage your electricity consumption	44%	67%
Comparison of your electricity consumption with your neighbours	41%	51%
Automated alert to predict your upcoming bill	40%	59%
Automated alert to remind you of your bill due date	34%	59%

Base: total respondents / total respondents from the 2017 UtilityPULSE Database



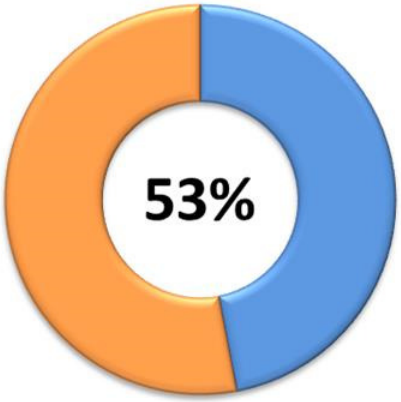


61%

"Feel it is 'important' to have Power Outage alerts ... "

Confidence in the industry

'Customers are well served by the electricity system in Ontario' – do you agree?



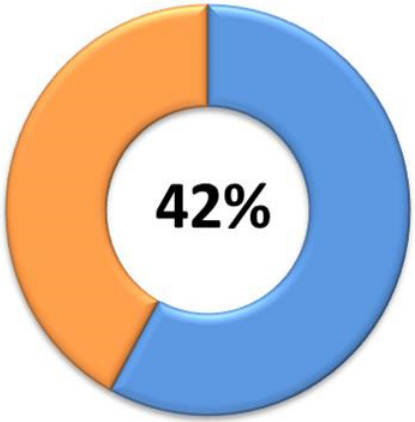
- 53% Agree ('strongly + somewhat') customers are well served by the electricity system in Ontario
- 5% neither agree or disagree
- 39% Disagree ('strongly + somewhat') they are well served
- 1% did not render an opinion or did not know

'Customers are well served by the electricity system in Ontario' – do you agree?			
	PUC Distribution	Ontario	UtilityPULSE Database
Top 2 Boxes: 'Strongly + Somewhat Agree'	53%	55%	56%

Base: total respondents / total respondents from the 2017 UtilityPULSE Database

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?



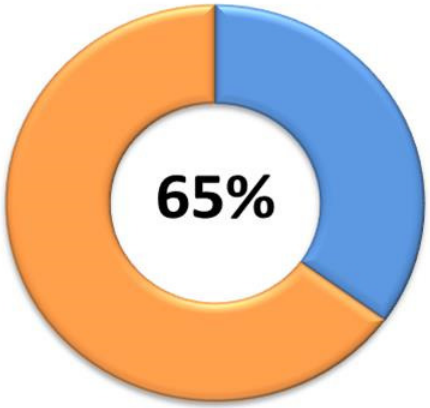
- 42% Agree ('strongly + somewhat') customers are confident that the electricity industry has the ability to meet future expectations regarding quality, reliability and price
- 6% neither agree or disagree
- 48% Disagree ('strongly + somewhat') that the industry can deliver on future expectations
- 2% 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?			
	PUC Distribution	Ontario	UtilityPULSE Database
Top 2 Boxes: 'Strongly + Somewhat Agree'	42%	43%	49%

Base: total respondents / total respondents from the 2017 UtilityPULSE Database

Confidence in the industry

'Customers are confident in the electricity industry's ability to keep up with technological changes' – do you agree?

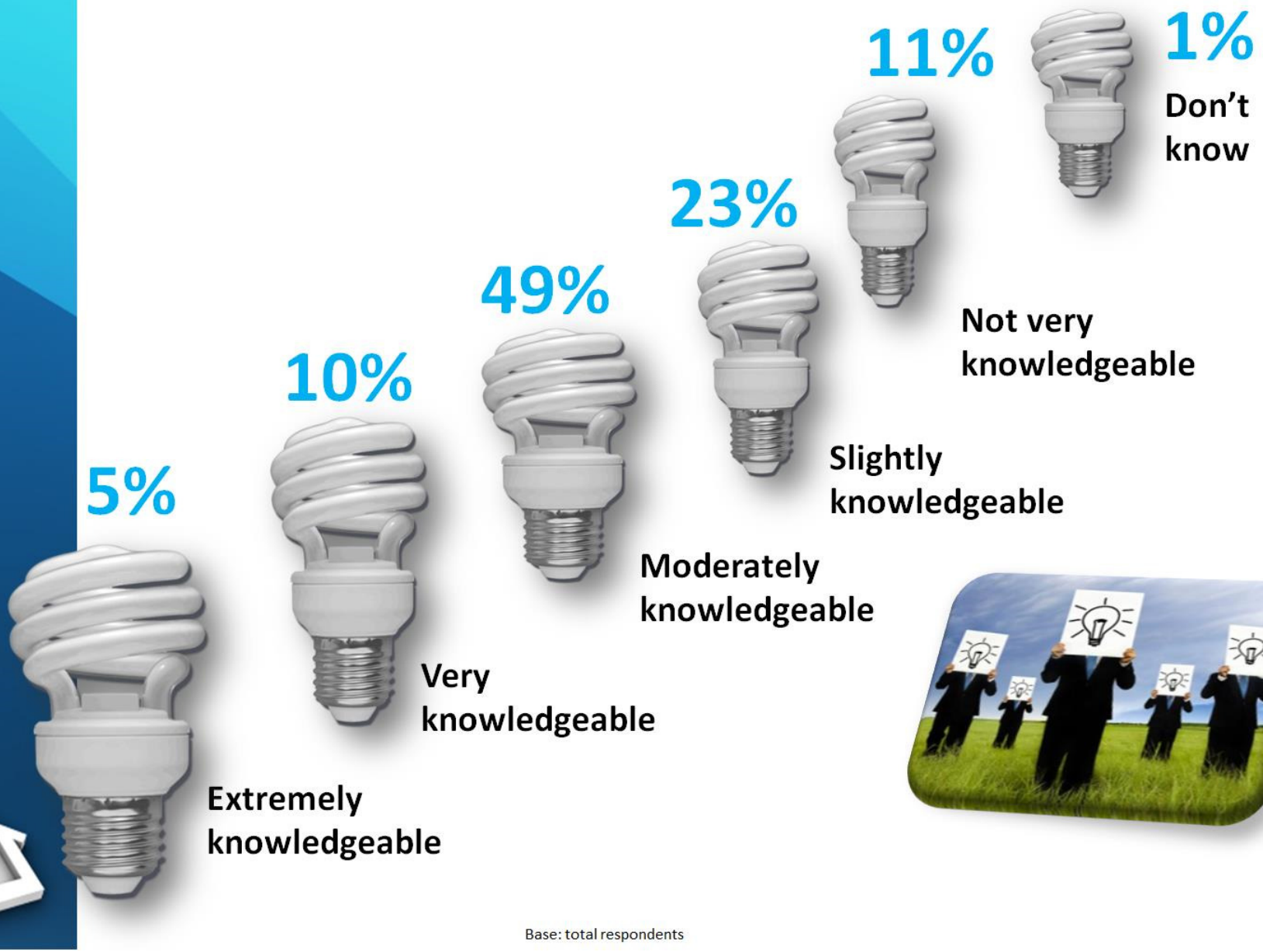


- 65% Agree ('strongly + somewhat') customers are confident that the electricity industry is able to keep up with technological changes
- 7% neither agree or disagree
- 23% Disagree ('strongly + somewhat') that the industry will keep up with changing technology
- 4% did not render an opinion or did not know

'Customer are confident in the electricity industry's ability to keep up with technological change' – do you agree?			
	PUC Distribution	Ontario	UtilityPULSE Database
Top 2 Boxes: 'Strongly + Somewhat Agree'	65%	52%	64%

Base: total respondents / total respondents from the 2017 UtilityPULSE Database

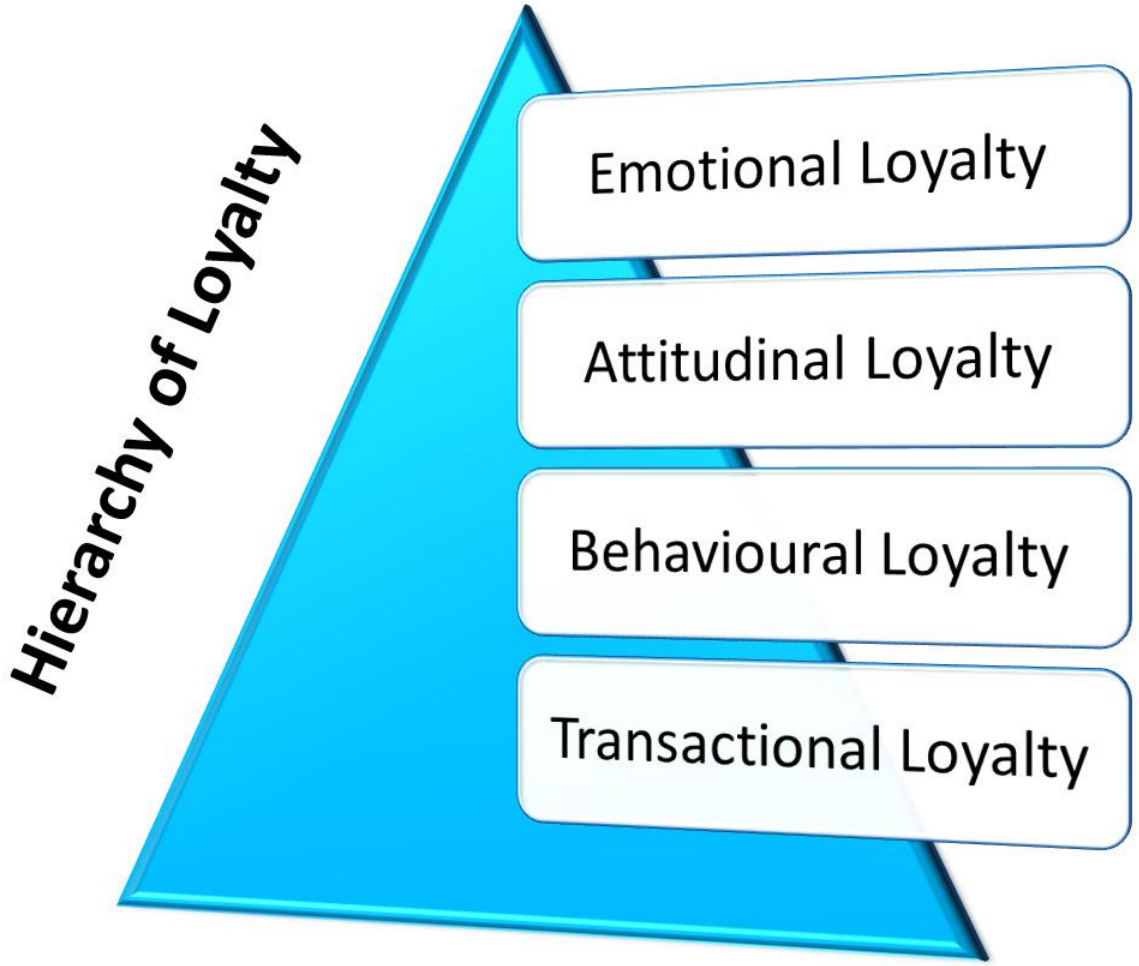
Electric Utility Industry Knowledge





Base: total respondents

Customer Loyalty



© UtilityPULSE

Customer Loyalty



19% Secure

18% Favorable

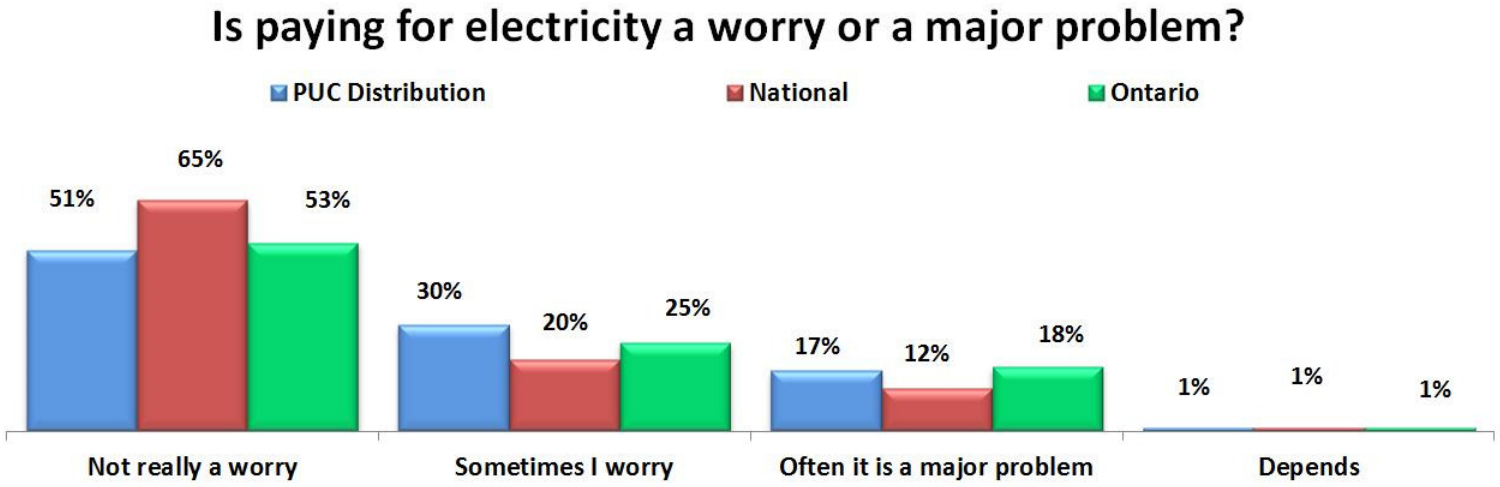
44% Indifferent

19% At Risk

Loyalty Factor			
	PUC Distribution	National	Ontario
Secure	19%	21%	14%
Favorable	18%	15%	12%
Indifferent	44%	51%	52%
At Risk	19%	14%	22%

Base: total respondents

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	61%	53%	37%
Sometimes I worry	25%	30%	37%
Often it is a major problem	12%	15%	25%
Depends	1%	0%	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.

Hydro prices “a worry”

PUC Distribution customers have been worried about hydro prices– more intensely and for a longer period of time than the rest of Ontario residents.



“WORRY ABOUT HYDRO PRICES IS ON THE RISE”

- In 2015, the Ontario benchmark for ‘I **often** worry or I **sometimes** worry’ was 37%.
- In 2015, PUC Distribution score for ‘I **often** worry or I **sometimes** worry’ was 42%; **customers were worried!**



- In 2017, the Ontario benchmark for ‘I **often** worry or I **sometimes** worry’ is 43%.
- In 2017, PUC Distribution ‘I **often** worry or I **sometimes** worry’ is at a high of 47%; **customers are very worried!**

Confidence in prioritizing investments:

85% **of Secure and Favourable respondents are confident that PUC Distribution is using good judgment to prioritize investments**

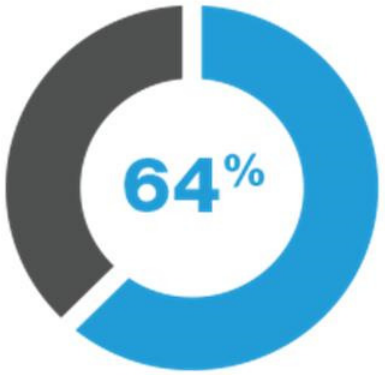


The 85% rating is the same as the UtilityPULSE database for Secure and Favourable customers.

Strategy for Replacing Equipment:

Strategy for replacing equipment		
PUC Distribution	**2017**	**2015**
Run-to-failure when there are limited customers affected ensures full-value is received from the equipment	20%	19%
Pro-active replacement, even though it may cost more, should ensure reliable power	64%	72%
Don't Know	16%	10%

Base: total respondents



"... of respondents believe PUC Distribution should be pro-actively replacing equipment, even if it costs more..."

Strategy for Replacing Equipment:

Strategy for replacing equipment		
PUC Distribution	**Residential**	**Small Commercial**
Run-to-failure when there are limited customers affected ensures full-value is received from the equipment	21%	13%
Pro-active replacement, even though it may cost more, should ensure reliable power	63%	68%
Don't Know	16%	18%

Base: total respondents

Strategy for replacing equipment			
PUC Distribution	**<$30K**	**$40 – 75K**	**$75K +**
Run-to-failure when there are limited customers affected ensures full-value is received from the equipment	20%	25%	19%
Pro-active replacement, even though it may cost more, should ensure reliable power	44%	63%	72%
Don't Know	37%	12%	9%

Base: total respondents



CAPITAL EXPENSES

Willing to pay more for which Capital items:

Which of the following CAPITAL items would you be willing to pay more for?					
PUC Distribution	Yes	No	Not sure	Residential Yes	Small Commercial Yes
Replacing aging equipment to improve safety and reliability	69%	29%	2%	69%	70%
Upgrading equipment to accommodate future growth in the community	50%	48%	2%	47%	63%
Adding automation and technology to reduce outage time	45%	52%	2%	43%	55%
Investing in technology to deal with cyber security issues	37%	58%	5%	37%	33%



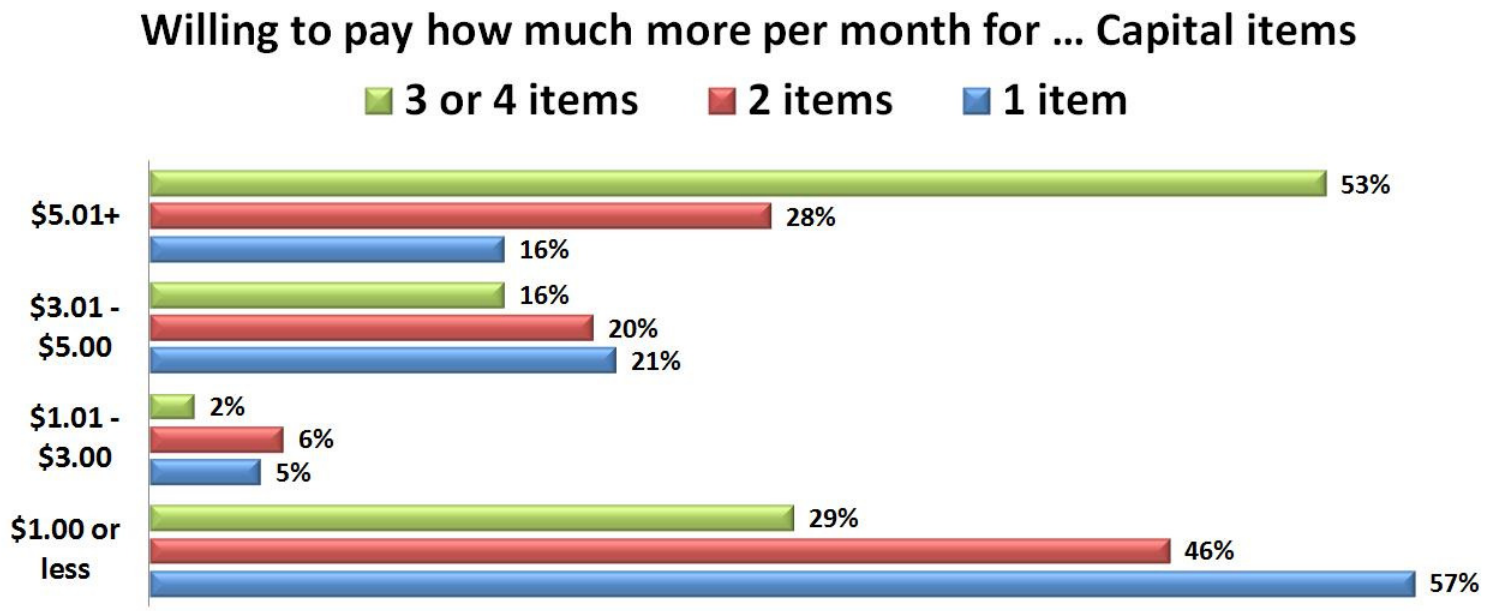
69%

"... of ALL respondents are willing to pay more per month to replace aging equipment to improve safety and reliability..."

Base: total respondents

Willing to pay How Much more:

Willing to pay how much more per month for … CAPITAL ITEMS			
PUC Distribution	1 item	2 items	3 or 4 items
$1.00 or less	57%	46%	29%
$1.01 - $3.00	5%	6%	2%
$3.01 - $5.00	21%	20%	16%
$5.01+	16%	28%	53%



Base: total respondents willing to pay more



OPERATING EXPENSES

Willing to pay more for which Operational items:

Which of the following OPERATIONAL items would you be willing to pay more for?					
PUC Distribution	Yes	No	Not sure	Residential Yes	Small Commercial Yes
A proactive outage management system	23%	74%	3%	23%	27%
Increased self-service options on the website	13%	85%	2%	13%	12%
Educating customers about energy conservation	23%	76%	1%	23%	22%



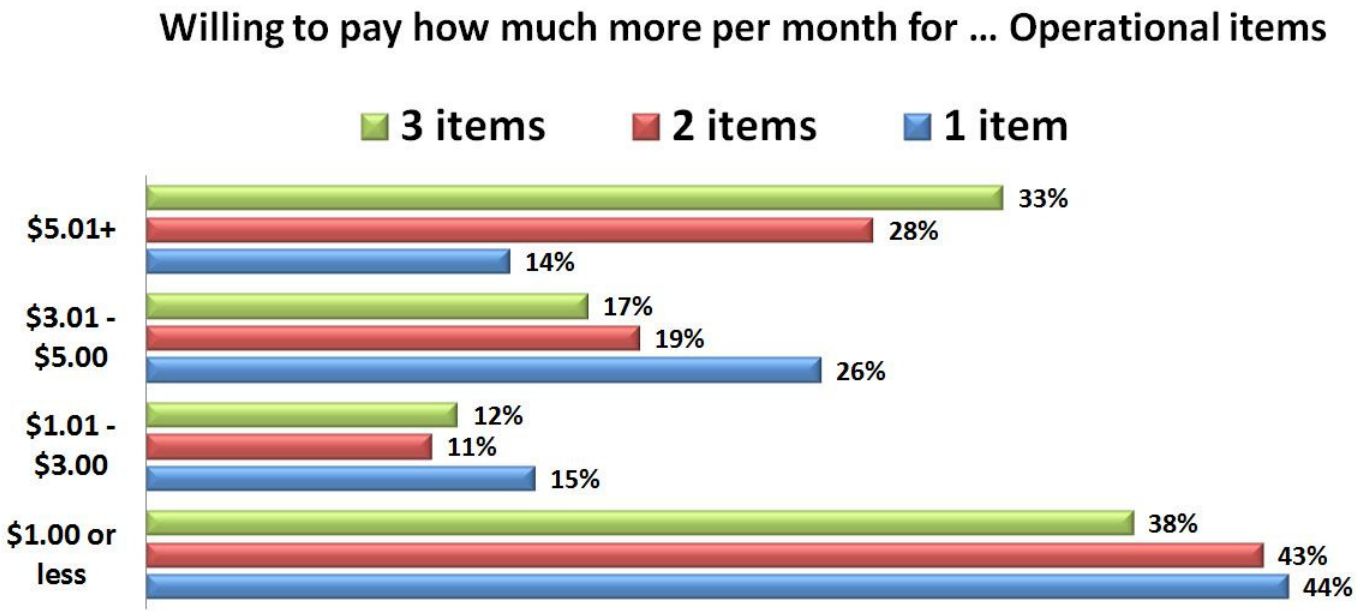


Base: total respondents

"... of ALL respondents are willing to pay more per month to have a proactive outage management system OR to educate customers about energy conservation..."

Willing to pay How Much more:

Willing to pay how much more per month for … OPERATIONAL ITEMS			
PUC Distribution	1 item	2 items	3 items
$1.00 or less	44%	43%	38%
$1.01 - $3.00	15%	11%	12%
$3.01 - $5.00	26%	19%	17%
$5.01+	14%	28%	33%



Base: total respondents willing to pay more

How can service be improved?

One or two most important things 'your local utility' could do to improve service	PUC Distribution
Better prices/lower rates	67%
Better communication with customers	8%
Improve reliability of power	4%
Be more efficient	3%
Eliminate SMART meters	3%
Better website presence	3%
Deal with delivery charges	3%
Improve/simplify/clarify billing	2%
Information & incentives on energy conservation	2%
Improve infrastructure	2%
Restore power faster	1%

Base: total respondents





"Better prices/lower rates..."

Marketing Communications

Marketing communications			
	PUC Distribution	National	Ontario
Topics which require more pro-active communication			
Cost of electricity is reasonable when compared to other utilities	44%	61%	48%
Provides good value for money	57%	62%	56%
Operates a cost effective electricity distribution system	62%	70%	56%
Provides information to help customers reduce their costs	75%	77%	74%
Adapts well to changes in customer expectations	68%	71%	68%
Topics that your utility scores very well on			
Delivers on its service commitments	85%	84%	83%
Electricity safety is a top priority	91%	87%	86%
Quickly handles outages and restores power	90%	87%	85%
Standard of reliability delivering electricity that meets expectations	89%	88%	86%
Provides consistent, reliable energy	91%	89%	89%

Base: total respondents



NUMBERS at a Glance



	PUC Distribution 2017	National 2017	Ontario 2017
Customer Satisfaction: Initial	82%	89%	84%
Customer Satisfaction: Post	80%	86%	76%
Overall Satisfaction with most recent experience	61%	72%	63%
Customer Experience Performance Rating (CEPr)	83%	82%	80%
Customer Centric Engagement Index (CCEI)	78%	78%	74%
Credibility & Trust Index	80%	80%	77%
UtilityPulse Report Card©	B+	B+	B

Simul

UtilityPULSE

SimulTRAINING

SimulSURVEY

Good things happen when work places work. You'll receive both strategic and pragmatic guidance about how to improve Customer & Employee satisfaction with leaders that lead and a front-line that is inspired. We provide: training, consulting, surveys, diagnostic tools and keynotes. The electric industry is a market segment that we specialize in.

Culture, Leadership & Performance – Organizational Development: Leadership development, Management development, Change Leadership, Organizational Culture, Performance Management, Strategic Planning, Teambuilding

Focus Groups, Surveys, Polls, Diagnostics: Diagnostics i.e. Change Readiness, Leadership Effectiveness, Managerial Competencies, Surveys & Polls, Customer Focus Groups, Employee Focus Groups, Customer Satisfaction and Loyalty Benchmarking Surveys

Customer Service Excellence: Service Excellence Leadership, Sales Skills, Telephone Skills, Customer Care Dealing with Difficult Customers, Problem Solving

For customer, employee or organization culture surveys,
your personal contact is:

Sid Ridgley

Phone: (905) 895-7900 Fax: (905) 905-895-7970
E-mail: sidridgley@utilitypulse.com or sridgley@simulcorp.com



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UtilityPULSE

A Division of Simul Corporation

Electric Utility
Customer Satisfaction Survey

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All comments and questions should be addressed to:
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UtilityPULSE division
Tel: 1-905-895-7900
email: sidridgley@utilitypulse.com or sridgley@simulcorp.com

Simul

APPENDIX 6

PUC Distribution Inc Audited Financial Statements 2013-2016

Financial Statements of

PUC DISTRIBUTION INC.

Year ended December 31, 2012

KPMG LLP
Chartered Accountants
111 Elgin Street, PO Box 578
Sault Ste. Marie ON P6A 5M6

Telephone (705) 949-5811
Fax (705) 949-0911
Internet www.kpmg.ca

INDEPENDENT AUDITORS' REPORT

To the Shareholder of PUC Distribution Inc.

We have audited the accompanying financial statements of PUC Distribution Inc., which comprise the balance sheet as at December 31, 2012 and the statements of earnings and comprehensive earnings and retained earnings 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 Canadian generally accepted accounting principles, 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 the 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.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of PUC Distribution Inc. as at December 31, 2012, and its results of operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

May 15, 2013
Sault Ste. Marie, Canada

KPMG LLP, is a Canadian limited liability partnership and a member firm of the KPMG network of independent member firms affiliated with KPMG International **Cooperative ("KPMG International"), a Swiss entity**. KPMG Canada provides services to KPMG LLP.

PUC DISTRIBUTION INC.

Balance Sheet

December 31, 2012, with comparative figures for 2011

	2012	2011
Assets		
Current assets:		
Cash	$ 538,117	$ 6,817,349
Accounts receivable	6,493,117	6,307,650
Unbilled revenue	9,233,411	8,895,916
Payment in lieu of taxes recoverable	461,484	407,935
Inventories	1,274,852	1,267,795
Prepaid expenses and deposits	63,926	61,134
	18,064,907	23,757,779
Property, plant and equipment (note 2)	128,112,006	96,776,288
Less accumulated amortization	51,975,297	48,231,553
	76,136,709	48,544,735
Regulatory assets (note 3)	-	4,933,372
Future taxes (note 7)	2,300,000	1,530,000
	$ 96,501,616	$ 78,765,886

	2012	2011
Liabilities and Shareholder's Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 11,339,857	$ 9,147,281
Customer deposits	731,582	859,734
Deferred revenue	765,490	1,023,745
Payable to PUC Services Inc. (note 5)	2,563,357	6,920,124
	15,400,286	17,950,884
Regulatory liabilities (note 3)	7,744,562	5,543,506
Long-term debt (note 4)	49,004,970	32,626,043
Shareholder's equity:		
Share capital:		
Authorized:		
Unlimited special shares, non-voting, non-cumulative, redeemable at $10,000 per share		
10,000 Common shares		
Issued and outstanding:		
8,612 Common shares	20,062,107	20,062,107
Retained earnings	4,289,691	2,583,346
	24,351,798	22,645,453
Contingent liability (note 6)		
	$ 96,501,616	$ 78,765,886

See accompanying notes to financial statements.

On behalf of the Board:

_____ Director

_____ Director

PUC DISTRIBUTION INC.

Statement of Earnings, Comprehensive Earnings and Retained Earnings

Year ended December 31, 2012, with comparative figures for 2011

	2012	2011
Revenue:		
Distribution	$ 17,453,153	$ 14,447,342
Energy charges	60,573,316	60,116,743
Other related charges	153,282	165,282
Other	1,827,816	1,758,730
	80,007,567	76,488,097
Cost of power	60,573,316	60,116,743
Gross profit	19,434,251	16,371,354
Investment income	62,138	182,850
Expenses:		
Distribution and transmission	5,854,025	5,159,341
Amortization of property, plant and equipment	4,320,787	3,335,388
Administration	2,626,539	1,884,570
Interest on long-term debt	1,656,468	1,618,576
Billing and collecting	1,163,141	1,111,440
Community relations	1,525,185	898,499
Other interest	242,677	85,084
	17,388,822	14,092,898
Earnings before the undernoted	2,107,567	2,461,306
Gain on sale of property and equipment	22,253	62,000
Earnings before provision for payment in lieu of taxes	2,129,820	2,523,306
Current income taxes (note 7)	423,475	466,500
Net earnings and comprehensive earnings	1,706,345	2,056,806
Retained earnings, beginning of year	2,583,346	526,540
Retained earnings, end of year	$ 4,289,691	$ 2,583,346

See accompanying notes to financial statements.

PUC DISTRIBUTION INC.

Statement of Cash Flows

Year ended December 31, 2012, with comparative figures for 2011

	2012	2011
Cash flows from operating activities:		
Net earnings and comprehensive earnings	$ 1,706,345	$ 2,056,806
Items not involving cash:		
Amortization of property, plant and equipment	4,320,787	3,335,388
Gain on sale of property	(22,253)	(62,000)
	6,004,879	5,330,194
Change in non-cash operating working capital:		
Increase in accounts receivable	(185,467)	(424,985)
Increase in unbilled revenue	(337,495)	(1,112,594)
Increase payment in lieu of taxes recoverable	(53,549)	10,920
Decrease (increase) in inventories	(7,057)	38,390
Increase in prepaid expenses and deposits	(2,792)	(29,614)
Increase in accounts payable and accrued liabilities	2,192,576	573,541
Decrease in customer deposits	(128,152)	(235,220)
Decrease in deferred revenue	(258,255)	(1,936,855)
	7,224,688	2,213,777
Cash flows from financing activities:		
Increase in long-term debt	16,378,927	1,092,003
Increase regulatory liabilities	1,431,056	1,166,541
Contributions in aid of construction	785,327	5,648,830
	18,595,310	7,907,374
Cash flows from investing activities:		
Increase (decrease) in payable to PUC Services	(4,356,767)	5,981,680
Decrease (increase) in regulatory assets	4,933,372	(128,313)
Proceeds from sale of property	39,150	67,550
Purchase of property, plant and equipment	(32,714,985)	(15,245,602)
	(32,099,230)	(9,324,685)
Increase (decrease) in cash position	(6,279,232)	796,466
Cash position, beginning of year	6,817,349	6,020,883
Cash position, end of year	$ 538,117	$ 6,817,349
Supplemental cash flow information:		
Cash paid during the year for:		
Interest	$ 1,656,468	$ 1,618,576
Payments in lieu of taxes	466,500	455,580

See accompanying notes to financial statements.

PUC Distribution Inc. (the "Company") is incorporated under the Business Corporations Act (Ontario) and as a wholly-owned subsidiary of PUC Inc., is the electric distribution utility for residents of the City of Sault Ste. Marie.

1. Significant accounting policies:

(a) Basis of presentation:

These financial statements have been prepared by management in accordance with the Canadian generally accepted accounting principles for rate regulated entities.

(b) Regulation:

The Ontario Energy Board Act, 1998 (Ontario) ("OEBA") conferred on the Ontario Energy Board ("OEB") increased powers and responsibilities to regulate the electricity industry in Ontario. These powers and responsibilities include approving or fixing rates for the transmission and distribution of electricity, providing continued rate protection for rural and remote electricity consumers, and ensuring that distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to electricity distributors 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. In its capacity to approve or set rates, the OEB has the authority to specify regulatory accounting treatments that may differ from Canadian generally accepted accounting principles for enterprises operating in a non-rate regulated environment.

The following regulatory treatments have resulted in accounting treatments that differ from Canadian generally accepted accounting principles ("GAAP") for enterprises operating in a non-regulated environment:

i) Regulatory assets and liabilities:

Regulatory assets represent costs that have been deferred because it is probable that they will be recovered from customers in future periods through the rate-making process. Regulatory liabilities represent future reduction in revenues associated with amounts that are expected to be refunded to customers through the rate-making process.

1. Significant accounting policies (continued):

(b) Regulation (continued):

ii) Payment in lieu of taxes:

As a municipally owned utility, the Company is exempt from Federal corporate income taxes. However, under the Electricity Act, 1998, the Company is required to make payments in lieu of corporate income and capital taxes to Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations.

Effective January 1, 2009, the Company adopted amendments to the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3465, Income Taxes and CICA Handbook Section 1100, Generally Accepted Accounting Principles. These amended sections establish new standards for the recognition, measurement, presentation and disclosure of future income tax assets and liabilities of rate regulated enterprises.

For transactions and events that cause temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, the Company recognized future income tax assets and liabilities, and corresponding regulatory liabilities and assets, as a result of adopting these amended standards on January 1, 2009.

Current taxes

The provision for current taxes and the assets and liabilities recognized for the current and prior periods are measured at the amounts receivable or payable from/to the OEFC.

Future taxes

Future taxes are provided for using the liability method and are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit.

Future tax liabilities are generally recognized on all taxable temporary differences and future tax assets are recognized to the extent that it is more likely than not that they be realized from taxable profits available against which deductible temporary differences can be utilized.

1. Significant accounting policies (continued):

(b) Regulation (continued):

ii) Payment in lieu of taxes (continued):

Future taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates (and tax laws) that have been enacted or substantively enacted by the balance sheet date. Future taxes are charged or credited to the statement of operations and comprehensive income.

The carrying amount of future tax assets is reviewed at each balance sheet date and reduced to the extent that all or part of the future tax assets have not met the “more likely than not” criterion. Previously unrecognized future income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more likely than not of being recovered from future taxable profits.

The Company has recognized regulatory assets and liabilities which correspond to future taxes that flow through the rate-making process.

(c) Inventories:

Inventories consist of parts, supplies and materials held for the future capital expansion and are valued at the lower of cost and net realizable value and items considered major spare parts are recorded as capital assets.

(d) Revenue recognition:

The Company recognizes energy charges revenue on the accrual basis and includes an estimate of unbilled revenue for electricity consumed since the date of each customer's last meter reading.

1. Significant accounting policies (continued):

(e) Financial instruments:

The Company accounts for its financial assets and liabilities in accordance with Canadian generally accepted accounting principles.

The financial instruments are classified into one of five categories: held-for-trading, held-to-maturity, loans and receivables, available-for-sale financial assets or other financial liabilities. All financial instruments, including derivatives, are measured in the balance sheet at fair value except for loans and receivables, held-to-maturity investments and other financial liabilities which are measured at amortized cost. Subsequent measurement and changes in fair value will depend on their initial classification, as follows: held-for-trading financial assets are measured at fair value and changes in fair value are recognized in net earnings; available-for-sale financial instruments are measured at fair value with changes in fair value recorded in other comprehensive income until the investment is derecognized or impaired at which time the amounts would be recorded in net earnings.

The Company has classified its financial instruments as follows:

Cash	Held-for-trading
Accounts receivable	Loans and receivables
Accounts payable and accrued liabilities	Other liabilities
Customer deposit	Other liabilities
Payable from PUC Services Inc.	Other liabilities
Long-term debt	Other liabilities

Comprehensive earnings:

In the event that the Company has any financial instruments that would impact other comprehensive earnings, a statement of comprehensive earnings would be included in the financial statements displaying the effects of the current period net income plus the impact on other comprehensive earnings resulting from these financial instruments.

1. Significant accounting policies (continued):

(f) Property, plant and equipment:

Property, plant and equipment are recorded at cost and include contracted services, materials, labour, engineering costs and overheads. Certain assets may be acquired or constructed with financial assistance in the form of contributions from developers or customers. The OEB requires that such contributions, whether in cash or in-kind, be offset against the related asset cost. Contributions in-kind are valued at their fair market values at the date of their contribution.

Amortization of property, plant and equipment is charged to operations on a straight-line basis using the following rates:

Asset	2012	2011
Building	2 to 4%	2 to 4%
Machinery and equipment	2.5 to 20%	2.5 to 20%
Transmission and distribution	1.67 to 6.67%	2.5 to 4%

Construction in progress comprises capital assets under construction, assets not yet placed into service and pre-construction activities related to specific projects expected to be constructed.

When identifiable assets, such as buildings, distribution station equipment and equipment and furniture are retired or otherwise disposed of, their original cost and accumulated amortization are removed from the accounts and the related gain or loss is included in the operating results for the related fiscal period. The cost and related accumulated amortization of grouped assets such as transmission and distribution facilities is removed from the accounts at the end of their estimated service life.

Property, plant and equipment are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated future cash flows, an impairment charge is recognized for the amount by which the carrying amount of the asset exceeds the fair value of the asset.

1. Significant accounting policies (continued):

(g) Asset retirement obligations:

The Company recognizes the fair value of a future asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that results from the acquisition, construction, development, and/or normal use of the assets. The Company concurrently recognizes a corresponding increase in the carrying amount of the related long-lived asset that is amortized over the life of the asset. The fair value of the asset retirement obligation is estimated using the expected cash flow approach that reflects a range of possible outcomes discounted at a credit-adjusted risk-free interest rate. Subsequent to the initial measurement, the asset retirement obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. Changes in the obligation due to the passage of time are recognized in income as an operating expense using the interest method. Changes in the obligation due to changes in estimated cash flows are recognized as an adjustment of the carrying amount of the related long-lived asset that is amortized over the remaining life of the asset.

Some of the Company's transmission and distribution assets may have asset retirement obligations. As the Company expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently a reasonable estimate of the fair value of any related asset retirement obligations cannot be made at this time. If, at some future date, it becomes possible to estimate the fair value cost of removing assets that the Company is legally required to remove, an asset retirement obligation will be recognized at that time.

(h) Customer deposits:

Customers may be required to post security to obtain electricity or other services. Where the security posted is in the form of cash or cash equivalents, these amounts are recorded in the accounts as customer deposits and invested in term deposits, which are held in trust by PUC Services Inc. Interest is paid on customer balances at rates established from time to time by the Company in accordance with regulation.

1. Significant accounting policies (continued):

(i) Measurement of uncertainty:

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and note disclosures related thereto. Due to the inherent uncertainty in making estimates, actual results could differ from estimates recorded in preparing these financial statements, including changes as a result of future regulatory decisions.

Accounts receivable and regulatory assets are stated after evaluation of amounts expected to be collected and an appropriate allowance for doubtful accounts. Inventory is recorded net of provisions for obsolescence. Amounts recorded for amortization of property, plant and equipment are based on estimates of useful service life.

(j) Adoption of new accounting standards:

Publicly accountable enterprises in Canada were required to adopt International Financial Reporting Standards ["IFRS"] in place of Canadian GAAP for annual reporting purposes for fiscal years beginning on or after January 1, 2011. The Accounting Standards Board has granted a series of deferrals for IFRS adoption for entities subject to rate regulation. The Company has elected to take the optional deferral of its adoption of IFRS; therefore, it continues to prepare its consolidated financial statements in accordance with Canadian GAAP in Part V of the CICA Handbook.

(l) Change in estimate:

Effective January 1, 2012, the Company revised its estimates of useful lives of certain items of property, plant and equipment and as a result changed its amortization rates. A comparative table of amortization rates is provided in Note 1(f). The impact of the change in 2012 was an increase to earnings before PILs of approximately $335,332. In accordance with OEB accounting guidelines, $335,332 has been recorded in regulatory liabilities, with an offsetting reduction to revenue. As a result, the impact on earnings before provision for payments in lieu of taxes is nil.

2. Property, plant and equipment:

	Cost	Accumulated amortization	2012 Net book value	2011 Net book value
Land	$ 845,039	$ -	$ 845,039	$ 837,214
Building	24,247,191	713,261	23,533,930	656,272
Machinery and equipment	27,618,193	12,679,493	14,938,700	14,785,416
Transmission and distribution	75,401,583	38,582,543	36,819,040	28,166,003
Construction in progress	-	-	-	4,099,830
	$ 128,112,006	$ 51,975,297	$ 76,136,709	$ 48,544,735

3. Regulatory assets and liabilities:

Regulatory assets and liabilities arise as a result of the rate-making process and consist of the following:

	2012	2011
Regulatory assets:		
Regulatory asset recovery account - Phase 2	$ -	$ 82,558
Smart meters	-	4,850,814
	$ -	$ 4,933,372
Regulatory liabilities:		
Settlement variances	$ (4,572,386)	$ (3,443,516)
Future taxes	(2,300,000)	(1,530,000)
Regulatory asset recovery account - Phase 3	(92,354)	(89,106)
Regulatory asset recovery account - Phase 4	(35,258)	(480,884)
Regulatory asset recovery account - Phase 5	(409,232)	-
Canadian GAAP Accounting Change	(335,332)	-
	$ (7,744,562)	$ (5,543,506)

The regulatory assets and liabilities balances of the Company are defined as follows:

3. Regulatory assets and liabilities (continued):

(a) Regulatory assets recovery account - Phase 3:

Through a 2010 rate application, the OEB approved the disposition of regulatory asset Group 1 accounts of $1,543,873 to be returned to customers over a one year period. The balance at December 31, 2012 was $92,354 (2011 - $89,106). Carrying charges, which amounted to $17,445 at December 31, 2012 (2011 - $14,197) are calculated monthly on the opening balance of the variance account using specific interest rate as outlined by the OEB.

(b) Regulatory assets recovery account - Phase 4:

Through a 2011 rate application, the OEB approved the disposition of regulatory asset Group 1 accounts of $1,020,945 to be returned to customers over a one year period. The balance at December 31, 2012 was $35,258 (2011 - $480,886). Carrying charges, which amounted to $(1,576) at December 31, 2012 (2011 - $2,585) are calculated monthly on the opening balance of the variance account using specific interest rates as outlined by the OEB.

(c) Regulatory assets recovery account - Phase 5:

Through a 2012 rate application, the OEB approved the disposition of regulatory asset accounts of $872,297 to be returned to customers over a one year period. The balance at December 31, 2012 was $409,233 (2011 - $Nil). Carrying charges, which amounted to $6,720 at December 31, 2012 (2011 - $Nil) are calculated monthly on the opening balance of the variance account using specific interest rates as outlined by the OEB.

(d) Canadian GAAP accounting changes:

The Board has approved a new variance account for distributors to record the financial differences arising as a result of the election to make accounting changes under Canadian GAAP in 2012 (or to make these changes as mandated by the Board in 2013, if applicable). The accounting changes include changes to depreciation rates and capitalization policies while still under Canadian GAAP in 2012.

The Company has elected to make both of the aforementioned accounting changes in 2012, resulting in $335,332 being recorded in regulatory liabilities.

3. Regulatory assets and liabilities (continued):

(e) Settlement variances:

Settlement variances represent the differences between the amounts charged by the Company to its customers based on regulated rates and the corresponding cost incurred by the LDC in the wholesale market administered by the IESO. The settlement variances relate primarily to carrying charges, non-competitive electricity charges, imported power charges and the global adjustment. Accordingly, the Company has deferred these recoveries in accordance with the criteria set out in the Accounting Procedures Handbook.

Carrying charges are calculated monthly on the opening balance of the applicable settlement variance account using a specific interest rate as outlined by the OEB.

On November 19, 2010 the Company made an application to the OEB to return to customers settlement variances as of December 31, 2009 totaling $1,020,945. The OEB approved the disposition of the settlement variances over a one year period commencing May 1, 2011.

On November 10, 2011, the Company made an application to the OEB to return to the customers settlement variances as of December 31, 2010 totalling $851,587. The OEB approved the disposition of the settlement variances over a one year period commencing May 1, 2012

On November 6, 2012, the Company made an application to the OEB to return to the customers settlement variances as of December 31, 2011 totalling $2,418,770.

The balance of $4,572,386 at December 31, 2012 (2011 - $3,443,516) is deferred in a regulatory liability account.

(g) Regulatory future income tax asset and liability:

Future income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit. The Company has recognized regulatory assets and liabilities which correspond to future taxes that flow through the rate-making process. In the absence of rate regulated accounting, the Company's provision for PILs would have been recognized using the liability method and there would not be regulatory accounts set up for taxes to be recovered through future rates. As a result, the provision for PILs would have been lower by approximately $770,000 (2011 - higher by $907,000) including the impact of a change in substantively enacted tax rates.

3. Regulatory assets and liabilities (continued):

(h) Fair value of regulatory assets (liabilities):

For certain regulatory items identified above, the expected recovery or settlement period or likelihood of recovery or settlement, is affected by risks and uncertainties related to the ultimate authority of the OEB in determining the asset's treatment for rate setting purposes.

Management continually assesses the likelihood of recovery of regulatory assets. If recovery through future rates is no longer considered possible, the amounts would be charged to the results of operations in the period the assessment is made.

4. Long-term debt:

	2012	2011
Note payable to parent company, PUC Inc.	$ 26,534,040	$ 26,534,040
Ontario Infrastructure Projects Corporation loan payable #1	5,000,000	5,000,000
Ontario Infrastructure Projects Corporation loan payable #2	17,470,930	1,092,003
	$ 49,004,970	$ 32,626,043

The note payable to parent company, PUC Inc., bears interest payable quarterly at rates periodically negotiated and principal payable one year after demand the average interest rate for 2012 was 6.1% (2011 - 6.1%).

The loan payable #1 to Ontario Infrastructure Projects Corporation ("OPIC"), bears interest payable monthly at a floating interest rate and principal. The floating interest rate is determined by OPIC based on OPIC's cost of funds plus OPIC's prevailing spread assigned to the borrowers sector for program delivery costs and risk. The average interest rate for 2012 was 1.79% (2011 - 1.75%). The loan is secured by a general security agreement and will converted to a 15 year debenture or repayable by October 31, 2014 if not debentured.

The loan payable #2 to Ontario Infrastructure Projects Corporation was for the construction of the new administration and operation facility. The total amount of the approved loan principal is $21,180,000 of which at December 31, 2012, $17,470,930 was drawn. Once the project is completed the loan will be repayable over 25 years by a blended monthly principal and interest payment at an interest rate to be determined, secured by a mortgage on the land and building and a general security agreement. The floating interest rate is determined by OPIC based on OPIC's cost of funds plus OPIC's prevailing spread assigned to the borrowers sector for program delivery costs and risk. The average interest rate for 2012 was 1.79% (2011 - 1.75%). A fixed interest rate will be determined once the project is completed.

5. Related party transactions:

The following entities are related parties of the Company:

The Corporation of the City of Sault Ste. Marie (City)	- 100% shareholder of PUC Inc.
PUC Inc. (Inc.)	- sole shareholder of the Company
PUC Services Inc. (Services)	- 100% owned by the Corporation of the City of Sault Ste. Marie
PUC Telecom Inc. (Telecom)	- 100% owned by PUC Inc.
Public Utilities Commission of the City of Sault Ste. Marie (Utility)	- 100% owned by the Corporation of the City of Sault Ste. Marie

The Company has a management, operation and maintenance agreement with PUC Services Inc., which has been extended to November 30, 2017, under which Services manages, controls, administers and operates the business of the Company.

The Company receives interest income on its receivable balance from Services at the Royal Bank prime less 2% on its average monthly balance. Interest of $51,403 (2011 - $89,358 earned) was paid during the year.

The Company provides electricity to the City which is the shareholder of the parent corporation, PUC Inc. Electrical energy is sold to the City at the same prices and terms as other electricity customers. The amount charged to the City for electricity consumed by streetlights is $1,437,164 (2011 - $1,383,792) and for other electricity consumption is $3,144,480 (2011 - $3,048,118).

Occupancy fees were charged by the Utility in the amount of $109,859 (2011 - $71,067).

Management fees were charged by PUC Services Inc. in the amount of $4,028,704 (2011 - $4,849,238) for an allocation of joint administrative and other expenses of which $2,563,357 is payable at year end (2011 - $6,920,124).

These transactions are in the normal course of operations and are measured at the exchange amount which is the amount of consideration agreed to by the related parties.

6. Contingent liability:

Purchasers of electricity in Ontario are required to provide security to the IESO to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees if PUC Distribution Inc. fails to make a payment required by a default notice issued by the IESO. In this regard, the Company has posted a letter of guarantee as security in the amount of $5,000,000 underwritten by the Company's bank.

7. Income taxes:

The provision for the payment in lieu of corporate income taxes (PILs) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

	2012	2011
Earnings before provision for payment in lieu of taxes	$ 2,129,820	$ 2,523,306
Tax at statutory rate of 26.5% (2011 - 28.25%)	$ 564,402	$ 712,830
Tax effect on disposition of assets	(925)	(8,760)
Amortization timing differences	(140,002)	(237,600)
Other	-	30
	$ 423,475	$ 466,500

The tax effects of temporary differences that give rise to significant portions of the future payment in lieu of taxes are presented below utilizing the substantively enacted Federal and Ontario combined future rate of 25%.

	2012	2011
Property, plant and equipment - differences in net book value and unamortized capital cost	$ 2,300,000	$ 1,530,000

8. Capital disclosures:

The Company's objective with respect to its capital structure is to maintain effective access to capital on an ongoing basis at reasonable rates while achieving appropriate rates of financial return for its shareholder.

The Company considers its capital structure to consist of shareholder's equity and notes payable held by the Company's shareholder which has been outlined below.

	2012	2011
Note payable to PUC Inc. - 6%	$ 26,534,040	$ 26,534,040
Common shares	20,062,107	20,062,107
Retained earnings (deficit)	4,289,691	2,583,346
	$ 50,885,838	$ 49,179,493

The Company is subject to a shareholder's agreement which has restrictive covenants typically associated with such an agreement. At December 31, 2012, the Company is in compliance with all of the covenants and restrictions.

PUC Distribution Inc. is a Corporation regulated by the Ontario Energy Board. The regulator has prescribed a phased in capital structure of 60% debt and 40% equity. For rate setting purposes the Company has complied with these requirements.

9. Credit risk and financial instruments:

(a) Financial instruments:

The carrying values of accounts receivable, payable to PUC Services Inc., customer deposits and accounts payable and accrued liabilities approximate fair value because of the short maturity of these instruments.

It is not practicable to determine the fair value of the notes payable as there are no principal repayment terms.

(b) Credit risk and concentrations of credit risk:

Financial assets held by the Company expose it to credit risk. As at December 31, 2012, there were no significant concentrations of credit risk with respect to any class of financial assets.

The Company earns its revenue from a broad base of customers located principally in Sault Ste. Marie. No single customer would account for revenue or an accounts receivable balance in excess of 10% of the respective reported balances.

9. Credit risk and financial instruments (continued):

(c) Interest rate risk:

The Company's long-term debt payable to Ontario Infrastructure Projects Corporation (OPIC) has a variable interest rate based on OPIC's cost of funds plus OPIC's prevailing spread assigned to the borrowers sector for program delivery costs and risk. As a result, the Company is exposed to interest rate risk due to fluctuations in OPIC's cost of funds and OPIC's prevailing spread assigned to the borrowers sector for program delivery costs and risk.

Financial Statements of

PUC DISTRIBUTION INC.

Year ended December 31, 2013

KPMG LLP
Chartered Accountants
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Sault Ste. Marie ON P6A 5M6

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INDEPENDENT AUDITORS' REPORT

To the Shareholder of PUC Distribution Inc.

We have audited the accompanying financial statements of PUC Distribution Inc., which comprise the balance sheet as at December 31, 2013 and the statements of earnings and comprehensive earnings and retained earnings 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 Canadian generally accepted accounting principles, 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 the 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.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of PUC Distribution Inc. as at December 31, 2013, and its results of operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

May 7, 2014
Sault Ste. Marie, Canada

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PUC DISTRIBUTION INC.

Balance Sheet

December 31, 2013, with comparative information for 2012

	2013	2012
Assets		
Current assets:		
Cash	$ 314,787	$ 538,117
Accounts receivable	7,886,094	6,493,117
Unbilled revenue	11,572,951	9,233,411
Payment in lieu of taxes recoverable	343,139	461,484
Inventories	1,675,485	1,274,852
Prepaid expenses and deposits	66,520	63,926
Current portion of regulatory assets (note 3)	771,711	-
	22,630,687	18,064,907
Property, plant and equipment (note 2)	134,063,688	128,112,006
Less accumulated amortization	52,595,690	51,975,297
	81,467,998	76,136,709
Regulatory assets (note 3)	50,924	-
Future taxes (note 7)	1,940,000	2,300,000
	$ 106,089,609	$ 96,501,616

	2013	2012
Liabilities and Shareholder's Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 10,702,293	$ 11,339,855
Customer deposits	712,536	731,582
Deferred revenue	1,227,075	765,490
Payable to PUC Services Inc. (note 5)	8,054,961	2,563,357
Current portion of long-term debt (note 4)	720,470	-
Current portion of regulatory liabilities (note 3)	3,053,420	2,012,206
	24,470,755	17,412,490
Regulatory liabilities (note 3)	3,238,482	5,732,358
Long-term debt (note 4)	51,917,609	49,004,970
	79,626,846	72,149,818
Shareholder's equity:		
Share capital:		
Authorized:		
Unlimited special shares, non-voting, non-cumulative, redeemable at $10,000 per share		
10,000 Common shares		
Issued and outstanding:		
8,612 Common shares	20,062,107	20,062,107
Retained earnings	6,400,656	4,289,691
	26,462,763	24,351,798
Contingent liability (note 6)		
	$ 106,089,609	$ 96,501,616

See accompanying notes to financial statements.

On behalf of the Board:

Director

Director

PUC DISTRIBUTION INC.

Statement of Earnings, Comprehensive Earnings and Retained Earnings

Year ended December 31, 2013, with comparative information for 2012

	2013	2012
Revenue:		
Distribution	16,735,058	17,453,153
Energy charges	68,769,142	60,573,316
Other related charges	149,806	153,282
Other	4,832,457	1,827,816
	90,486,463	80,007,567
Cost of power	68,769,142	60,573,316
Gross profit	21,717,321	19,434,251
Investment income	41,984	62,138
	21,759,305	19,496,389
Expenses:		
Distribution and transmission	5,992,121	5,854,025
Amortization of property, plant and equipment	3,538,651	4,320,787
Administration	4,438,267	2,626,539
Interest on long-term debt	2,184,394	1,656,468
Billing and collecting	1,274,108	1,163,141
Community relations	1,882,536	1,525,185
Other interest	191,706	242,677
	19,501,783	17,388,822
Earnings before the undernoted	2,257,522	2,107,567
Gain (loss) on sale of property and equipment	(110,632)	22,253
Earnings before provision for payment in lieu of taxes	2,146,890	2,129,820
Current income taxes (note 7)	35,925	423,475
Net earnings and comprehensive earnings	2,110,965	1,706,345
Retained earnings, beginning of year	4,289,691	2,583,346
Retained earnings, end of year	$ 6,400,656	$ 4,289,691

See accompanying notes to financial statements.

PUC DISTRIBUTION INC.

Statement of Cash Flows

Year ended December 31, 2013, with comparative information for 2012

	2013	2012
Cash flows from operating activities:		
Net earnings and comprehensive earnings	$ 2,110,965	$ 1,706,345
Items not involving cash:		
Amortization of property, plant and equipment	3,538,651	4,320,787
(Gain) loss on sale of property	110,632	(22,253)
	5,760,248	6,004,879
Change in non-cash operating working capital:		
Increase in accounts receivable	(1,392,977)	(185,467)
Increase in unbilled revenue	(2,339,540)	(337,495)
Increase (decrease) payment in lieu of taxes recoverable	118,345	(53,549)
Increase in inventories	(400,633)	(7,057)
Increase in prepaid expenses and deposits	(2,594)	(2,792)
Increase (decrease) in accounts payable and accrued liabilities	(637,565)	2,192,576
Decrease in customer deposits	(19,046)	(128,152)
Increase (decrease) in deferred revenue	461,585	(258,255)
	1,547,823	7,224,688
Cash flows from financing activities:		
Increase in long-term debt	3,633,109	16,378,927
Increase (decrease) regulatory liabilities	(1,092,660)	1,431,056
Contributions in aid of construction	1,376,260	785,327
	3,916,709	18,595,310
Cash flows from investing activities:		
Decrease (increase) in regulatory assets	(822,635)	4,933,372
Proceeds from sale of property	1,440,693	39,150
Increase (decrease) in payable to PUC Services	5,491,605	(4,356,767)
Purchase of property, plant and equipment	(11,797,525)	(32,714,985)
	(5,687,862)	(32,099,230)
Decrease in cash	(223,330)	(6,279,232)
Cash beginning of year	538,117	6,817,349
Cash end of year	$ 314,787	$ 538,117
Supplemental cash flow information:		
Cash paid during the year for:		
Interest	$ 2,184,394	$ 1,656,468
Payments in lieu of taxes	398,555	466,500

See accompanying notes to financial statements.

PUC Distribution Inc. (the "Company") is incorporated under the Business Corporations Act (Ontario) and as a wholly-owned subsidiary of PUC Inc., is the electric distribution utility for residents of the City of Sault Ste. Marie.

1. Significant accounting policies:

(a) Basis of presentation:

These financial statements have been prepared by management in accordance with the Canadian generally accepted accounting principles for rate regulated entities.

(b) Regulation:

The Ontario Energy Board Act, 1998 (Ontario) ("OEBA") conferred on the Ontario Energy Board ("OEB") increased powers and responsibilities to regulate the electricity industry in Ontario. These powers and responsibilities include approving or fixing rates for the transmission and distribution of electricity, providing continued rate protection for rural and remote electricity consumers, and ensuring that distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to electricity distributors 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. In its capacity to approve or set rates, the OEB has the authority to specify regulatory accounting treatments that may differ from Canadian generally accepted accounting principles for enterprises operating in a non-rate regulated environment.

The following regulatory treatments have resulted in accounting treatments that differ from Canadian generally accepted accounting principles ("GAAP") for enterprises operating in a non-regulated environment:

i) Regulatory assets and liabilities:

Regulatory assets represent costs that have been deferred because it is probable that they will be recovered from customers in future periods through the rate-making process. Regulatory liabilities represent future reduction in revenues associated with amounts that are expected to be refunded to customers through the rate-making process.

1. Significant accounting policies (continued):

(b) Regulation (continued):

ii) Payment in lieu of taxes:

As a municipally owned utility, the Company is exempt from Federal corporate income taxes. However, under the Electricity Act, 1998, the Company is required to make payments in lieu of corporate income and capital taxes to Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations.

Effective January 1, 2009, the Company adopted amendments to the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3465, Income Taxes and CICA Handbook Section 1100, Generally Accepted Accounting Principles. These amended sections establish new standards for the recognition, measurement, presentation and disclosure of future income tax assets and liabilities of rate regulated enterprises.

For transactions and events that cause temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, the Company recognized future income tax assets and liabilities, and corresponding regulatory liabilities and assets, as a result of adopting these amended standards on January 1, 2009.

Current taxes

The provision for current taxes and the assets and liabilities recognized for the current and prior periods are measured at the amounts receivable or payable from/to the OEFC.

Future taxes

Future taxes are provided for using the liability method and are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit.

Future tax liabilities are generally recognized on all taxable temporary differences and future tax assets are recognized to the extent that it is more likely than not that they be realized from taxable profits available against which deductible temporary differences can be utilized.

1. Significant accounting policies (continued):

(b) Regulation (continued):

ii) Payment in lieu of taxes (continued):

Future taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates (and tax laws) that have been enacted or substantively enacted by the balance sheet date. Future taxes are charged or credited to the statement of operations and comprehensive income.

The carrying amount of future tax assets is reviewed at each balance sheet date and reduced to the extent that all or part of the future tax assets have not met the “more likely than not” criterion. Previously unrecognized future income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more likely than not of being recovered from future taxable profits.

The Company has recognized regulatory assets and liabilities which correspond to future taxes that flow through the rate-making process.

(c) Inventories:

Inventories consist of parts, supplies and materials held for the future capital expansion and are valued at the lower of cost and net realizable value and items considered major spare parts are recorded as capital assets.

(d) Revenue recognition:

The Company recognizes energy charges revenue on the accrual basis and includes an estimate of unbilled revenue for electricity consumed since the date of each customer's last meter reading.

1. Significant accounting policies (continued):

(e) Financial instruments:

The Company accounts for its financial assets and liabilities in accordance with Canadian generally accepted accounting principles.

The financial instruments are classified into one of five categories: held-for-trading, held-to-maturity, loans and receivables, available-for-sale financial assets or other financial liabilities. All financial instruments, including derivatives, are measured in the balance sheet at fair value except for loans and receivables, held-to-maturity investments and other financial liabilities which are measured at amortized cost. Subsequent measurement and changes in fair value will depend on their initial classification, as follows: held-for-trading financial assets are measured at fair value and changes in fair value are recognized in net earnings; available-for-sale financial instruments are measured at fair value with changes in fair value recorded in other comprehensive income until the investment is derecognized or impaired at which time the amounts would be recorded in net earnings.

The Company has classified its financial instruments as follows:

Cash	Held-for-trading
Accounts receivable	Loans and receivables
Accounts payable and accrued liabilities	Other liabilities
Customer deposit	Other liabilities
Payable from PUC Services Inc.	Other liabilities
Long-term debt	Other liabilities

Comprehensive earnings:

In the event that the Company has any financial instruments that would impact other comprehensive earnings, a statement of comprehensive earnings would be included in the financial statements displaying the effects of the current period net income plus the impact on other comprehensive earnings resulting from these financial instruments.

1. Significant accounting policies (continued):

(f) Property, plant and equipment:

Property, plant and equipment are recorded at cost and include contracted services, materials, labour, engineering costs and overheads. Certain assets may be acquired or constructed with financial assistance in the form of contributions from developers or customers. The OEB requires that such contributions, whether in cash or in-kind, be offset against the related asset cost. Contributions in-kind are valued at their fair market values at the date of their contribution.

Amortization of property, plant and equipment is charged to operations on a straight-line basis using the following rates:

Asset	2013 Rate
Building	2% to 4%
Machinery and equipment	2.5% to 20%
Transmission and distribution	1.67% to 6.67%

Construction in progress comprises capital assets under construction, assets not yet placed into service and pre-construction activities related to specific projects expected to be constructed.

When identifiable assets, such as buildings, distribution station equipment and equipment and furniture are retired or otherwise disposed of, their original cost and accumulated amortization are removed from the accounts and the related gain or loss is included in the operating results for the related fiscal period. The cost and related accumulated amortization of grouped assets such as transmission and distribution facilities is removed from the accounts at the end of their estimated service life.

Property, plant and equipment are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated future cash flows, an impairment charge is recognized for the amount by which the carrying amount of the asset exceeds the fair value of the asset.

1. Significant accounting policies (continued):

(g) Asset retirement obligations:

The Company recognizes the fair value of a future asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that results from the acquisition, construction, development, and/or normal use of the assets. The Company concurrently recognizes a corresponding increase in the carrying amount of the related long-lived asset that is amortized over the life of the asset. The fair value of the asset retirement obligation is estimated using the expected cash flow approach that reflects a range of possible outcomes discounted at a credit-adjusted risk-free interest rate. Subsequent to the initial measurement, the asset retirement obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. Changes in the obligation due to the passage of time are recognized in income as an operating expense using the interest method. Changes in the obligation due to changes in estimated cash flows are recognized as an adjustment of the carrying amount of the related long-lived asset that is amortized over the remaining life of the asset.

Some of the Company's transmission and distribution assets may have asset retirement obligations. As the Company expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently a reasonable estimate of the fair value of any related asset retirement obligations cannot be made at this time. If, at some future date, it becomes possible to estimate the fair value cost of removing assets that the Company is legally required to remove, an asset retirement obligation will be recognized at that time.

(h) Customer deposits:

Customers may be required to post security to obtain electricity or other services. Where the security posted is in the form of cash or cash equivalents, these amounts are recorded in the accounts as customer deposits and invested in term deposits, which are held in trust by PUC Services Inc. Interest is paid on customer balances at rates established from time to time by the Company in accordance with regulation.

1. Significant accounting policies (continued):

(i) Measurement of uncertainty:

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and note disclosures related thereto. Due to the inherent uncertainty in making estimates, actual results could differ from estimates recorded in preparing these financial statements, including changes as a result of future regulatory decisions.

Accounts receivable and regulatory assets are stated after evaluation of amounts expected to be collected and an appropriate allowance for doubtful accounts. Inventory is recorded net of provisions for obsolescence. Amounts recorded for amortization of property, plant and equipment are based on estimates of useful service life.

(j) Adoption of new accounting standards:

Publicly accountable enterprises in Canada were required to adopt International Financial Reporting Standards ["IFRS"] in place of Canadian GAAP for annual reporting purposes for fiscal years beginning on or after January 1, 2011. The Accounting Standards Board has granted a series of deferrals for IFRS adoption for entities subject to rate regulation. The Company has elected to take the optional deferral of its adoption of IFRS; therefore, it continues to prepare its consolidated financial statements in accordance with Canadian GAAP in Part V of the CICA Handbook.

2. Property, plant and equipment:

			2013	2012
	Cost	Accumulated amortization	Net book value	Net book value
Land	$ 845,595	$ -	$ 845,595	$ 845,039
Building	26,108,658	1,230,032	24,878,626	23,533,930
Machinery and equipment	27,585,745	13,408,928	14,176,817	14,938,700
Transmission and distribution	79,516,902	37,956,730	41,560,172	36,819,040
Construction in progress	6,788	-	6,788	-
	$ 134,063,688	$ 52,595,690	$ 81,467,998	$ 76,136,709

3. Regulatory assets and liabilities:

Regulatory assets and liabilities arise as a result of the rate-making process and consist of the following:

	2013	2012
Regulatory assets consist of the following:		
Current portion of regulatory assets		
Stranded Meters	$ 717,645	$ -
LRAMVA	54,066	-
	$ 771,711	$ -
Long-term portion of regulatory assets		
Smart Meter Entity (SME) Charges	$ 23,891	$ -
LRAMVA	27,033	-
Total regulatory assets	$ 50,924	$ -
Current portion of regulatory liabilities:		
Settlement Variances	$ (1,352,526)	$ (1,483,920)
Regulatory asset recovery account - Phase 3	-	(46,177)
Regulatory asset recovery account - Phase 4	(19,736)	-
Regulatory asset recovery account - Phase 5	-	(409,233)
Regulatory asset recovery account - Phase 6	(1,608,282)	-
CGAAP Accounting Changes	(72,876)	(72,876)
	$ (3,053,420)	$ (2,012,206)
Long-term portion of regulatory liabilities		
Settlement Variances	$ (1,113,278)	$ (3,088,466)
Future Taxes	(1,940,000)	(2,300,000)
Regulatory asset recovery account - Phase 3	-	(46,177)
Regulatory asset recovery account - Phase 4	(9,868)	(35,258)
Regulatory asset recovery account - Phase 5	(29,586)	-
CGAAP Accounting Changes	(145,750)	(262,456)
Total regulatory liabilities	$ (3,238,482)	$ (5,732,358)

3. Regulatory assets and liabilities (continued):

The regulatory assets and liabilities balances of the Company are defined as follows:

(a) Regulatory assets recovery account - Phase 3:

Through a 2010 rate application, the OEB approved the disposition of regulatory asset Group 1 accounts of $1,543,873 to be returned to customers over a one year period. The balance at December 31, 2013 was $Nil (2012 - $92,354). Carrying charges, which amounted to $Nil at December 31, 2013 (2012 - $17,445) are calculated monthly on the opening balance of the variance account using specific interest rate as outlined by the OEB.

(b) Regulatory assets recovery account - Phase 4:

Through a 2011 rate application, the OEB approved the disposition of regulatory asset Group 1 accounts of $1,020,945 to be returned to customers over a one year period. The balance at December 31, 2013 was $29,603 (2012 - $35,258). Carrying charges, which amounted to $7,231 at December 31, 2013 (2012 - $1,576) are calculated monthly on the opening balance of the variance account using specific interest rates as outlined by the OEB.

(c) Regulatory assets recovery account - Phase 5:

Through a 2012 rate application, the OEB approved the disposition of regulatory asset accounts of $872,297 to be returned to customers over a one year period. The balance at December 31, 2013 was $29,586 (2012 - $409,233). Carrying charges, which amounted to $8,510 at December 31, 2013 (2012- $6,720) are calculated monthly on the opening balance of the variance account using specific interest rates as outlined by the OEB.

(d) Regulatory assets recovery account - Phase 6:

Through a 2013 rate application, the OEB approved the disposition of regulatory asset accounts of $2,638,187 to be returned to customers over a one year period. The balance at December 31, 2013 was $1,608,283 (2012 - $Nil). Carrying charges, which amounted to ($12,998) at December 31, 2013 (2012 - $Nil) are calculated monthly on the opening balance of the variance account using specific interest rates as outlined by the OEB.

3. Regulatory assets and liabilities (continued):

(e) Canadian GAAP accounting changes:

The Board has approved a new variance account for distributors to record the financial differences arising as a result of the election to make accounting changes under Canadian GAAP in 2012 (or to make these changes as mandated by the Board in 2013, if applicable). The accounting changes include changes to depreciation rates and capitalization policies while still under Canadian GAAP in 2012. The Company has elected to make both of the aforementioned accounting changes in 2012, resulting in $218,626 at December 31, 2013 (2012 - $335,332) being recorded in regulatory liabilities.

(f) Settlement variances:

Settlement variances represent the differences between the amounts charged by the Company to its customers based on regulated rates and the corresponding cost incurred by the LDC in the wholesale market administered by the IESO. The settlement variances relate primarily to carrying charges, non-competitive electricity charges, imported power charges and the global adjustment. Accordingly, the Company has deferred these recoveries in accordance with the criteria set out in the Accounting Procedures Handbook.

Carrying charges are calculated monthly on the opening balance of the applicable settlement variance account using a specific interest rate as outlined by the OEB.

On November 19, 2010 the Company made an application to the OEB to return to customers settlement variances as of December 31, 2009 totaling $1,020,945. The OEB approved the disposition of the settlement variances over a one year period commencing May 1, 2011.

On November 10, 2011, the Company made an application to the OEB to return to the customers settlement variances as of December 31, 2010 totalling $851,587. The OEB approved the disposition of the settlement variances over a one year period commencing May 1, 2012.

On November 6, 2012, the Company made an application to the OEB to return to the customers settlement variances as of December 31, 2011. The OEB approved the disposition of settlement variances over a 10 month period of $2,638,187 commencing July 1, 2013.

On October 11, 2013 the company made an application to the OEB to return to the customers settlement variance of $2,058,392 at December 31, 2013. The OEB approved the disposition settlement variances over a one year period commencing May 1, 2014.

The balance of $2,465,804 at December 31, 2013 (2012 - $4,572,386) is deferred in a regulatory liability account.

3. Regulatory assets and liabilities (continued):

(g) Lost Revenue Adjustment Mechanism Variance Account (LRMVA)

For Conservation and Demand Management (CDM) programs delivered within the 2011-2014 period, the OEB established a LRAMVA to capture the variance between the OEB approved CDM forecast and the actual results. The total received for CDM losses is $81,098 at December 31, 2013 (2012 - $Nil).

(h) Stranded Meters Variance Account

Through a 2013 rate application, the OEB approved the disposition of the Company's stranded meters resulting from the deployment of Smart Meters for an amount of $1,349,557. The balance at December 31, 2013 was $717,645 (2012 - $Nil). Carrying charges, which amounts to $6,758 at December 31, 2013 (2012 - $Nil) are calculated monthly on the opening balance of the variance account using specific interest rates as outlines by the OEB.

(i) Smart Meter Entity (SME) Charge Variance Account:

In its role as the SME, the IESO is managing the development of the meter data management/repository (MDM/R) to collect, manage, store and retrieve information related to the metering of customers' use of electricity in Ontario. Effective May 1, 2013, the SME charge is levied and collected by licensed distributors (LDC's) from customers at $0.79 per month until October 31, 2018. The LDC's will incur SME charges monthly from the IESO. A variance account will be used to track the difference between SME revenues and expenses. The balance at December 31, 2013 was $23,891 (2012 - $Nil) are calculated monthly on the opening balance of the variance account using specific interest rates as outline by the OEB.

(j) Regulatory future income tax asset and liability:

Future income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit. The Company has recognized regulatory assets and liabilities which correspond to future taxes that flow through the rate-making process. In the absence of rate regulated accounting, the Company's provision for PILs would have been recognized using the liability method and there would not be regulatory accounts set up for taxes to be recovered through future rates. As a result, the provision for PILs would have been higher by approximately $360,000 (2012 - lower by $770,000) including the impact of a change in substantively enacted tax rates.

3. Regulatory assets and liabilities (continued):

(k) Fair value of regulatory assets (liabilities):

For certain regulatory items identified above, the expected recovery or settlement period or likelihood of recovery or settlement, is affected by risks and uncertainties related to the ultimate authority of the OEB in determining the asset's treatment for rate setting purposes.

Management continually assesses the likelihood of recovery of regulatory assets. If recovery through future rates is no longer considered possible, the amounts would be charged to the results of operations in the period the assessment is made.

4. Long-term debt:

	2013	2012
Note payable to parent company, PUC Inc.	$ 26,534,040	$ 26,534,040
Ontario Infrastructure and Lands Corporation loan payable #1	5,000,000	5,000,000
Ontario Infrastructure and Lands Corporation loan payable #2	21,104,039	17,470,930
	52,638,079	49,004,970
Current portion of long-term debt	720,470	-
	$ 51,917,609	$ 49,004,970

Principal repayments are due as follows:

2014	$ 720,470
2015	752,049
2016	785,022
2017	819,452
2018	855,405
	$ 3,932,398

The note payable to parent company, PUC Inc., bears interest payable quarterly at rates periodically negotiated and principal payable one year after demand. The average interest rate for 2013 was 6.1% (2012 - 6.1%).

The loan payable #1 to Ontario Infrastructure and Lands Corporation ("OILC"), for the Smart Meter deployment project, bears interest payable monthly at an interest rate of 3.82% and repayable by blended semi - annual principal and interest payments of $220,498, maturing July

4. Long-term debt (continued):

17, 2028.

The loan payable #2 to Ontario Infrastructure and Lands Corporation was for the construction of the new administration and operation facility, bears interest at a rate of 4.61%. The loan will be repayable over 25 years by a blended monthly principal and interest payments of $118,568 and matures on October 1, 2038. The loan is secured by a mortgage on the land and building and a general security agreement .

5. Related party transactions:

The following entities are related parties of the Company:

The Corporation of the City of Sault Ste. Marie (City)	- 100% shareholder of PUC Inc.
PUC Inc. (Inc.)	- sole shareholder of the Company
PUC Services Inc. (Services)	- 100% owned by the Corporation of the City of Sault Ste. Marie
PUC Telecom Inc. (Telecom)	- 100% owned by PUC Inc.
Public Utilities Commission of the City of Sault Ste. Marie (Utility)	- 100% owned by the Corporation of the City of Sault Ste. Marie

The Company has a management, operation and maintenance agreement with PUC Services Inc., which has been extended to November 30, 2017, under which Services manages, controls, administers and operates the business of the Company.

The Company pays interest on its payable balance to Services at the OEB prescribed short-term borrowing rate on its average monthly balance. Interest of $94,644 (2012 - $51,403 earned) was paid during the year.

The Company provides electricity to the City which is the shareholder of the parent corporation, PUC Inc. Electrical energy is sold to the City at the same prices and terms as other electricity customers. The amount charged to the City for electricity consumed by streetlights is $1,544,632 (2012 - $1,437,164) and for other electricity consumption is $3,847,668 (2012 - $3,144,480).

Occupancy fees were charged by the Utility in the amount of $98,651 (2012 - $109,859)

Management fees were charged by PUC Services Inc. in the amount of $5,902,657 (2012 - $4,028,704) for an allocation of joint administrative and other expenses.

These transactions are in the normal course of operations and are measured at the exchange amount which is the amount of consideration agreed to by the related parties.

6. Contingent liability:

Purchasers of electricity in Ontario are required to provide security to the IESO to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees if PUC Distribution Inc. fails to make a payment required by a default notice issued by the IESO. In this regard, the Company has posted a letter of guarantee as security in the amount of $5,000,000 underwritten by the Company's bank.

7. Income taxes:

The provision for the payment in lieu of corporate income taxes (PILs) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

	2013	2012
Earnings before provision for payment in lieu of taxes	$ 2,146,890	$ 2,129,820
Tax at statutory rate of 26.5% (2012 - 26.5%)	$ 568,926	$ 564,402
Tax effect on disposition of assets	29,317	(925)
Amortization timing differences	(526,432)	(140,002)
Other	405	-
Prior year over provision	(19,491)	-
Provincial small business rate	(16,800)	-
	$ 35,925	$ 423,475

The tax effects of temporary differences that give rise to significant portions of the future payment in lieu of taxes are presented below utilizing the substantively enacted Federal and Ontario combined future rate of 26.5%.

	2013	2012
Property, plant and equipment - differences in net book value and unamortized capital cost	$ 1,940,000	$ 2,300,000

8. Capital disclosures:

The Company's objective with respect to its capital structure is to maintain effective access to capital on an ongoing basis at reasonable rates while achieving appropriate rates of financial return for its shareholder.

The Company considers its capital structure to consist of shareholder's equity and notes payable held by the Company's shareholder which has been outlined below.

	2013	2012
Note payable to PUC Inc. - 6.1%	$ 26,534,040	$ 26,534,040
Common shares	20,062,107	20,062,107
Retained earnings	6,400,656	4,289,695
	$ 52,996,803	$ 50,885,842

The Company is subject to a shareholder's agreement which has restrictive covenants typically associated with such an agreement. At December 31, 2013, the Company is in compliance with all of the covenants and restrictions.

PUC Distribution Inc. is a Corporation regulated by the Ontario Energy Board. The regulator has prescribed a capital structure of 60% debt and 40% equity. For rate setting purposes the Company has complied with these requirements.

9. Credit risk and financial instruments:

(a) Financial instruments:

The carrying values of accounts receivable, payable to PUC Services Inc., customer deposits and accounts payable and accrued liabilities approximate fair value because of the short maturity of these instruments.

It is not practicable to determine the fair value of the notes payable as there are no principal repayment terms.

(b) Credit risk and concentrations of credit risk:

Financial assets held by the Company expose it to credit risk. As at December 31, 2013, there were no significant concentrations of credit risk with respect to any class of financial assets.

The Company earns its revenue from a broad base of customers located principally in Sault Ste. Marie. No single customer would account for revenue or an accounts receivable balance in excess of 10% of the respective reported balances.

9. Credit risk and financial instruments (continued):

(c) Interest rate risk:

The Company pays interest on its payable to PUC Services Inc. balance at the OEB prescribed short term debt rate. As a result, the Company is exposed to interest rate risk due to fluctuations in the OEB prescribed short term debt rate. These fluctuations could affect the level of interest expense of the Company.

Financial Statements of

PUC DISTRIBUTION INC.

Year ended December 31, 2014

KPMG LLP
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INDEPENDENT AUDITORS' REPORT

To the Shareholder of PUC Distribution Inc.

We have audited the accompanying financial statements of PUC Distribution Inc., which comprise the balance sheet as at December 31, 2014 and the statements of earnings and comprehensive earnings and retained earnings 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 Canadian generally accepted accounting principles, 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 the 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.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of PUC Distribution Inc. as at December 31, 2014, and its results of operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

April 15, 2015
Sault Ste. Marie, Canada

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KPMG Canada provides services to KPMG LLP.

PUC DISTRIBUTION INC.

Balance Sheet

December 31, 2014, with comparative information for 2013

	2014	2013
Assets		
Current assets:		
Cash	$ 4,118,664	$ 314,787
Accounts receivable	7,544,347	7,886,094
Unbilled revenue	10,004,921	11,572,951
Payment in lieu of taxes recoverable	497,819	343,139
Inventories	1,614,472	1,675,485
Prepaid expenses and deposits	62,200	66,520
Current portion of regulatory assets (note 3)	28,521	771,711
	23,870,944	22,630,687
Property, plant and equipment (note 2)	140,656,186	134,063,688
Less accumulated amortization	56,092,472	52,595,690
	84,563,714	81,467,998
Regulatory assets (note 3)	1,482,115	50,924
Future taxes (note 7)	1,403,460	1,940,000
	$ 111,320,233	$ 106,089,609

	2014	2013
Liabilities and Shareholder's Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 10,791,840	$ 10,702,293
Customer deposits	854,761	712,536
Deferred revenue	563,782	1,227,075
Payable to PUC Services Inc. (note 5)	1,945,721	8,054,961
Current portion of long-term debt (note 4)	15,752,049	720,470
Current portion of regulatory liabilities (note 3)	1,153,830	3,053,420
	31,061,983	24,470,755
Regulatory liabilities (note 3)	1,482,458	3,238,482
Long-term debt (note 4)	51,165,560	51,917,609
	83,710,001	79,626,846
Shareholder's equity:		
Share capital:		
Authorized:		
Unlimited special shares, non-voting, non-cumulative, redeemable at $10,000 per share		
10,000 Common shares		
Issued and outstanding:		
8,612 Common shares	20,062,107	20,062,107
Retained earnings	7,548,125	6,400,656
	27,610,232	26,462,763
Contingent liability (note 6)		
	$ 111,320,233	$ 106,089,609

See accompanying notes to financial statements.

On behalf of the Board:

Director

Director

PUC DISTRIBUTION INC.

Statement of Earnings, Comprehensive Earnings and Retained Earnings

Year ended December 31, 2014, with comparative information for 2013

	2014	2013
Revenue:		
Distribution	16,386,768	16,735,058
Energy charges	70,473,134	68,769,142
Other related charges	148,327	149,806
Other	3,995,623	4,832,457
	91,003,852	90,486,463
Cost of power	70,473,134	68,769,142
Gross profit	20,530,718	21,717,321
Investment income	7,555	41,984
	20,538,273	21,759,305
Expenses:		
Distribution and transmission	5,773,407	5,992,121
Amortization of property, plant and equipment	3,657,061	3,538,651
Administration	3,332,931	4,438,267
Interest on long-term debt	2,756,657	2,184,394
Community relations	2,516,075	1,882,536
Billing and collecting	1,373,301	1,274,108
Other interest	259,935	191,706
	19,669,367	19,501,783
Earnings before the undernoted	868,906	2,257,522
Loss on sale of equipment	-	(110,632)
Earnings before provision for payment in lieu of taxes	868,906	2,146,890
Current income taxes (recovery) (note 7)	(278,563)	35,925
Net earnings and comprehensive earnings	1,147,469	2,110,965
Retained earnings, beginning of year	6,400,656	4,289,691
Retained earnings, end of year	$ 7,548,125	$ 6,400,656

See accompanying notes to financial statements.

PUC DISTRIBUTION INC.

Statement of Cash Flows

Year ended December 31, 2014, with comparative information for 2013

	2014	2013
Cash flows from operating activities:		
Net earnings and comprehensive earnings	$ 1,147,469	$ 2,110,965
Items not involving cash:		
Amortization of property, plant and equipment	3,657,061	3,538,651
Loss on sale of equipment	-	110,632
	4,804,530	5,760,248
Change in non-cash operating working capital:		
Decrease (increase) in accounts receivable	341,747	(1,392,977)
Decrease (increase) in unbilled revenue	1,568,030	(2,339,540)
Increase (decrease) payment in lieu of taxes recoverable	(154,680)	118,345
Decrease (increase) in inventories	61,013	(400,633)
Decrease (increase) in prepaid expenses and deposits	4,320	(2,594)
Increase (decrease) in accounts payable and accrued liabilities	89,546	(637,565)
Increase (decrease) in customer deposits	142,225	(19,046)
Increase (decrease) in deferred revenue	(663,293)	461,585
	6,193,438	1,547,823
Cash flows from financing activities:		
Increase in long-term debt	15,000,000	3,709,069
Repayment of long-term debt	(720,470)	(75,960)
Decrease regulatory liabilities	(3,119,074)	(1,092,660)
Contributions in aid of construction	1,045,731	1,376,260
	12,206,187	3,916,709
Cash flows from investing activities:		
Increase in regulatory assets	(688,001)	(822,635)
Loss from sale of equipment	-	1,440,693
Increase (decrease) in payable to PUC Services	(6,109,240)	5,491,605
Purchase of property, plant and equipment	(7,798,507)	(11,797,525)
	(14,595,748)	(5,687,862)
Increase (decrease) in cash	3,803,877	(223,330)
Cash, beginning of year	314,787	538,117
Cash, end of year	$ 4,118,664	$ 314,787
Supplemental cash flow information:		
Cash paid during the year for:		
Interest	$ 2,756,657	$ 2,184,394
Payments in lieu of taxes	199,278	398,555

See accompanying notes to financial statements.

PUC Distribution Inc. (the "Company") is incorporated under the Business Corporations Act (Ontario) and as a wholly-owned subsidiary of PUC Inc., is the electric distribution utility for residents of the City of Sault Ste. Marie.

1. Significant accounting policies:

(a) Basis of presentation:

These financial statements have been prepared by management in accordance with the Canadian generally accepted accounting principles for rate regulated entities.

(b) Regulation:

The Ontario Energy Board Act, 1998 (Ontario) ("OEBA") conferred on the Ontario Energy Board ("OEB") increased powers and responsibilities to regulate the electricity industry in Ontario. These powers and responsibilities include approving or fixing rates for the transmission and distribution of electricity, providing continued rate protection for rural and remote electricity consumers, and ensuring that distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to electricity distributors 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. In its capacity to approve or set rates, the OEB has the authority to specify regulatory accounting treatments that may differ from Canadian generally accepted accounting principles for enterprises operating in a non-rate regulated environment.

The following regulatory treatments have resulted in accounting treatments that differ from Canadian generally accepted accounting principles ("GAAP") for enterprises operating in a non-regulated environment:

i) Regulatory assets and liabilities:

Regulatory assets represent costs that have been deferred because it is probable that they will be recovered from customers in future periods through the rate-making process. Regulatory liabilities represent future reduction in revenues associated with amounts that are expected to be refunded to customers through the rate-making process.

1. Significant accounting policies (continued):

(b) Regulation (continued):

ii) Payment in lieu of taxes:

As a municipally owned utility, the Company is exempt from taxes under the Income Tax Act (Canada) ("ITA") and the Ontario Corporations Tax Act ("OCTA").

Pursuant to the Electricity Act ("EA"), 1998, the Company is required to make payments in lieu of taxes under the ITA and OCTA and remit such amounts to the Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the ITA and the OCTA as modified by the Electricity Act, 1998, and related regulations.

The Company applies the asset and liability method of accounting for payments in lieu of income taxes. Under the asset and liability method, future tax assets and liabilities are recognized, to the extent such are determined likely to be realized, for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Future tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to be recovered or settled. The effect on future tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the date of enactment or substantive enactment.

Future income taxes recoverable have been recorded in the accounts and a corresponding regulatory liability has been set up as future income taxes are recovered through future rate increases/decreases.

(c) Inventories:

Inventories consist of parts, supplies and materials held for the future capital expansion and are valued at the lower of cost and net realizable value and items considered major spare parts are recorded as capital assets.

(d) Revenue recognition:

The Company recognizes energy charges revenue on the accrual basis and includes an estimate of unbilled revenue for electricity consumed since the date of each customer's last meter reading.

1. Significant accounting policies (continued):

(e) Financial instruments:

The Company accounts for its financial assets and liabilities in accordance with Canadian generally accepted accounting principles.

The financial instruments are classified into one of five categories: held-for-trading, held-to-maturity, loans and receivables, available-for-sale financial assets or other financial liabilities. All financial instruments, including derivatives, are measured in the balance sheet at fair value except for loans and receivables, held-to-maturity investments and other financial liabilities which are measured at amortized cost. Subsequent measurement and changes in fair value will depend on their initial classification, as follows: held-for-trading financial assets are measured at fair value and changes in fair value are recognized in net earnings; available-for-sale financial instruments are measured at fair value with changes in fair value recorded in other comprehensive income until the investment is derecognized or impaired at which time the amounts would be recorded in net earnings.

The Company has classified its financial instruments as follows:

Cash	Held-for-trading
Accounts receivable	Loans and receivables
Unbilled revenue	Loans and receivables
Accounts payable and accrued liabilities	Other liabilities
Customer deposits	Other liabilities
Payable from PUC Services Inc.	Other liabilities
Long-term debt	Other liabilities

Comprehensive earnings:

In the event that the Company has any financial instruments that would impact other comprehensive earnings, a statement of comprehensive earnings would be included in the financial statements displaying the effects of the current period net income plus the impact on other comprehensive earnings resulting from these financial instruments.

1. Significant accounting policies (continued):

(f) Property, plant and equipment:

Property, plant and equipment are recorded at cost and include contracted services, materials, labour, engineering costs and overheads. Certain assets may be acquired or constructed with financial assistance in the form of contributions from developers or customers. The OEB requires that such contributions, whether in cash or in-kind, be offset against the related asset cost. Contributions in-kind are valued at their fair market values at the date of their contribution.

Amortization of property, plant and equipment is charged to operations on a straight-line basis using the following rates:

Asset	Rate
Building	2% to 4%
Machinery and equipment	2.5% to 20%
Transmission and distribution	1.67% to 6.67%

Construction in progress comprises capital assets under construction, assets not yet placed into service and pre-construction activities related to specific projects expected to be constructed.

When identifiable assets, such as buildings, distribution station equipment and equipment and furniture are retired or otherwise disposed of, their original cost and accumulated amortization are removed from the accounts and the related gain or loss is included in the operating results for the related fiscal period. The cost and related accumulated amortization of grouped assets such as transmission and distribution facilities is removed from the accounts at the end of their estimated service life.

Property, plant and equipment are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated future cash flows, an impairment charge is recognized for the amount by which the carrying amount of the asset exceeds the fair value of the asset.

1. Significant accounting policies (continued):

(g) Asset retirement obligations:

The Company recognizes the fair value of a future asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that results from the acquisition, construction, development, and/or normal use of the assets. The Company concurrently recognizes a corresponding increase in the carrying amount of the related long-lived asset that is amortized over the life of the asset. The fair value of the asset retirement obligation is estimated using the expected cash flow approach that reflects a range of possible outcomes discounted at a credit-adjusted risk-free interest rate. Subsequent to the initial measurement, the asset retirement obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. Changes in the obligation due to the passage of time are recognized in income as an operating expense using the interest method. Changes in the obligation due to changes in estimated cash flows are recognized as an adjustment of the carrying amount of the related long-lived asset that is amortized over the remaining life of the asset.

Some of the Company's transmission and distribution assets may have asset retirement obligations. As the Company expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently a reasonable estimate of the fair value of any related asset retirement obligations cannot be made at this time. If, at some future date, it becomes possible to estimate the fair value cost of removing assets that the Company is legally required to remove, an asset retirement obligation will be recognized at that time.

1. Significant accounting policies (continued):

(h) Customer deposits:

Customers may be required to post security to obtain electricity or other services. Where the security posted is in the form of cash or cash equivalents, these amounts are recorded in the accounts as customer deposits, which are held in trust by PUC Services Inc. Interest is paid on customer balances at rates established from time to time by the Company in accordance with regulation.

(i) Measurement of uncertainty:

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and note disclosures related thereto. Due to the inherent uncertainty in making estimates, actual results could differ from estimates recorded in preparing these financial statements, including changes as a result of future regulatory decisions.

Accounts receivable and regulatory assets are stated after evaluation of amounts expected to be collected and an appropriate allowance for doubtful accounts. Inventory is recorded net of provisions for obsolescence. Amounts recorded for amortization of property, plant and equipment are based on estimates of useful service life.

(j) Adoption of new accounting standards:

i) Publicly accountable enterprises in Canada were required to adopt International Financial Reporting Standards ["IFRS"] in place of Canadian GAAP for annual reporting purposes for fiscal years beginning on or after January 1, 2011. The Accounting Standards Board has granted a series of deferrals for IFRS adoption for entities subject to rate regulation. The Company has elected to take the optional deferral of its adoption of IFRS; therefore, it continues to prepare its financial statements in accordance with Canadian GAAP in Part V of the CPA Canada Handbook - Accounting.

1. Significant accounting policies (continued):

(j) Adoption of new accounting standards (continued):

ii) The International Accounting Standards Board ("IASB") issued IFRS 14 Regulatory Deferral Accounts in January 2014. This standard provides specific guidance on accounting for the effects of rate regulation and permits first-time adopters of IFRS to continue using previous GAAP to account for regulatory deferral account balances while the IASB completes its comprehensive project in this area. Adoption of this standard is optional for entities eligible to use it. Deferral account balances and movements in the balances will be required to be presented as separate line items on the face of the financial statements distinguished from assets, liabilities, income and expenses that are recognized in accordance with other IFRSs. Extensive disclosures will be required to enable users of the financial statements to understand the features and nature of and risks associated with rate regulation and the effect of rate regulation on the Company's financial position, performance and cash flows.

2. Property, plant and equipment:

			2014	2013
	Cost	Accumulated amortization	Net book value	Net book value
Land	$ 852,393	$ -	$ 852,393	$ 845,595
Building	26,327,087	1,731,553	24,595,534	24,878,626
Machinery and equipment	29,570,082	14,092,945	15,477,137	14,176,817
Transmission and distribution	83,906,624	40,267,974	43,638,650	41,560,172
Construction in progress	-	-	-	6,788
	$ 140,656,186	$ 56,092,472	$ 84,563,714	$ 81,467,998

3. Regulatory assets and liabilities:

Regulatory assets and liabilities arise as a result of the rate-making process and consist of the following:

	2014	2013
Regulatory assets consist of the following:		
Current portion of regulatory assets		
Stranded Meters	$ 4,015	$ 717,645
LRAMVA	24,506	54,066
	$ 28,521	$ 771,711
Long-term portion of regulatory assets		
Settlement Variances	$ 1,415,937	$ -
Smart Meter Entity (SME) Charges	23,889	23,891
LRAMVA	12,253	27,033
Regulatory asset recovery account - Phase 6	30,036	-
Total long-term regulatory assets	$ 1,482,115	$ 50,924
Current portion of regulatory liabilities:		
Settlement Variances	$ -	$ (1,352,526)
Regulatory asset recovery account - Phase 4	-	(19,736)
Regulatory asset recovery account - Phase 6	-	(1,608,282)
Regulatory asset recovery account - Phase 7	(1,080,955)	-
CGAAP Accounting Changes	(72,875)	(72,876)
	$ (1,153,830)	$ (3,053,420)
Long-term portion of regulatory liabilities		
Settlement Variances	$ -	$ (1,113,278)
Future Taxes	(1,380,000)	(1,940,000)
Regulatory asset recovery account - Phase 4	-	(9,868)
Regulatory asset recovery account - Phase 5	(29,584)	(29,586)
CGAAP Accounting Changes	(72,874)	(145,750)
Total long-term regulatory liabilities	$ (1,482,458)	$ (3,238,482)

3. Regulatory assets and liabilities (continued):

The regulatory assets and liabilities balances of the Company are defined as follows:

(a) Regulatory liability recovery account - Phase 4:

Through a 2011 rate application, the OEB approved the disposition of regulatory liability Group 1 accounts of $1,020,945 to be returned to customers over a one year period. The balance at December 31, 2014 was $Nil (2013 - $29,603). Carrying charges, which amounted to $8,644 at December 31, 2014 (2013 - $7,231) are calculated monthly on the opening balance of the variance account using specific interest rates as outlined by the OEB.

(b) Regulatory liability recovery account - Phase 5:

Through a 2012 rate application, the OEB approved the disposition of regulatory liability accounts of $851,587 to be returned to customers over a one year period. The balance at December 31, 2014 was $29,584 (2013 - $29,586). Carrying charges, which amounted to $8,860 at December 31, 2014 (2013 - $8,510) are calculated monthly on the opening balance of the variance account using specific interest rates as outlined by the OEB.

(c) Regulatory asset recovery account - Phase 6:

Through a 2013 rate application, the OEB approved the disposition of regulatory liability accounts of $2,638,187 to be returned to customers over a one year period. The balance at December 31, 2014 was $30,036 (2013 - ($1,608,283)). Carrying charges, which amounted to $16,836 at December 31, 2014 (2013 - $($12,998)) are calculated monthly on the opening balance of the variance account using specific interest rates as outlined by the OEB.

(d) Regulatory liability recovery account - Phase 7:

Through a 2014 rate application, the OEB approved the disposition of regulatory liability accounts of $2,058,392 to be returned to customers over a one year period. The balance at December 31, 2014 was $1,080,954 (2013 - $Nil). Carrying charges, which amounted to $16,314 at December 31, 2014 (2013 - $Nil) are calculated monthly on the opening balance of the variance account using specific interest rates as outlined by the OEB.

3. Regulatory assets and liabilities (continued):

(e) Canadian GAAP accounting changes:

The Board has approved a new variance account for distributors to record the financial differences arising as a result of the election to make accounting changes under Canadian GAAP in 2012 (or to make these changes as mandated by the Board in 2013, if applicable). The accounting changes include changes to depreciation rates and capitalization policies while still under Canadian GAAP in 2012. The Company has elected to make both of the aforementioned accounting changes in 2012, resulting in $145,750 at December 31, 2014 (2013 - $218,626) being recorded in regulatory liabilities.

(f) Settlement variances:

Settlement variances represent the differences between the amounts charged by the Company to its customers based on regulated rates and the corresponding cost incurred by the LDC in the wholesale market administered by the IESO. The settlement variances relate primarily to carrying charges, non-competitive electricity charges, imported power charges and the global adjustment. Accordingly, the Company has deferred these recoveries in accordance with the criteria set out in the Accounting Procedures Handbook.

Carrying charges are calculated monthly on the opening balance of the applicable settlement variance account using a specific interest rate as outlined by the OEB.

On November 19, 2010, the Company made an application to the OEB to return to customers settlement variances as of December 31, 2009 totaling $1,020,945. The OEB approved the disposition of the settlement variances over a one year period commencing May 1, 2011.

On November 10, 2011, the Company made an application to the OEB to return to the customers settlement variances as of December 31, 2010 totaling $851,587. The OEB approved the disposition of the settlement variances over a one year period commencing May 1, 2012.

On November 6, 2012, the Company made an application to the OEB to return to the customers settlement variances as of December 31, 2011. The OEB approved the disposition of settlement variances over a 10 month period of $2,638,187 commencing July 1, 2013.

On October 11, 2013, the Company made an application to the OEB to return to the customers settlement variance of $2,058,392 at December 31, 2013. The OEB approved the disposition settlement variances over a one year period commencing May 1, 2014.

The balance of $1,415,937 at December 31, 2014 (2013 - ($2,465,804)) is deferred in a regulatory asset (liability) account.

3. Regulatory assets and liabilities (continued):

(g) Lost Revenue Adjustment Mechanism Variance Account (LRMVA)

For Conservation and Demand Management (CDM) programs delivered within the 2011-2014 period, the OEB established a LRAMVA to capture the variance between the OEB approved CDM forecast and the actual results. The total received for CDM losses is $36,758 at December 31, 2014 (2013 - $81,098).

(h) Stranded Meters Variance Account

Through a 2013 rate application, the OEB approved the disposition of the Company's stranded meters resulting from the deployment of Smart Meters for an amount of $1,349,557. The balance at December 31, 2014 was $4,015 (2013 - $717,645). Carrying charges, which amounts to $9,498 at December 31, 2014 (2013 - $6,758) are calculated monthly on the opening balance of the variance account using specific interest rates as outlines by the OEB.

(i) Smart Meter Entity (SME) Charge Variance Account:

In its role as the SME, the IESO is managing the development of the meter data management/repository (MDM/R) to collect, manage, store and retrieve information related to the metering of customers' use of electricity in Ontario. Effective May 1, 2013, the SME charge is levied and collected by licensed distributors (LDC's) from customers at $0.79 per month until October 31, 2018. The LDC's will incur SME charges monthly from the IESO. A variance account will be used to track the difference between SME revenues and expenses. The balance at December 31, 2014 was $23,889 (2013 - $23,891) are calculated monthly on the opening balance of the variance account using specific interest rates as outline by the OEB.

(j) Regulatory future income tax asset and liability:

Future income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit. The Company has recognized regulatory assets and liabilities which correspond to future taxes that flow through the rate-making process. In the absence of rate regulated accounting, the Company's provision for PILs would have been recognized using the liability method and there would not be regulatory accounts set up for taxes to be recovered through future rates. As a result, the provision for PILs would have been higher by approximately $560,000 (2013 - $360,000) including the impact of a change in substantively enacted tax rates.

3. Regulatory assets and liabilities (continued):

(k) Fair value of regulatory assets (liabilities):

For certain regulatory items identified above, the expected recovery or settlement period or likelihood of recovery or settlement, is affected by risks and uncertainties related to the ultimate authority of the OEB in determining the asset's treatment for rate setting purposes.

Management continually assesses the likelihood of recovery of regulatory assets. If recovery through future rates is no longer considered possible, the amounts would be charged to the results of operations in the period the assessment is made.

4. Long-term debt:

	2014	2013
Note payable to parent company, PUC Inc.	$ 26,534,040	$ 26,534,040
Ontario Infrastructure and Lands Corporation loan payable #1	4,747,620	5,000,000
Ontario Infrastructure and Lands Corporation loan payable #2	20,635,949	21,104,039
Ontario Infrastructure and Lands Corporation loan payable #3	15,000,000	-
	66,917,609	52,638,079
Current portion of long-term debt	15,752,049	720,470
	$ 51,165,560	$ 51,917,609

Principal repayments are due as follows:

2015	$ 15,752,049
2016	785,022
2017	819,453
2018	855,405
2019	892,946
	$ 19,104,875

The unsecured note payable to parent company, PUC Inc., bears interest payable quarterly at rates periodically negotiated and principal payable one year after demand. The average interest rate for 2014 was 6.1% (2013 - 6.1%).

4. Long-term debt (continued):

The loan payable #1 to Ontario Infrastructure and Lands Corporation ("OILC"), for the Smart Meter deployment project, secured by a second ranking general security agreement, bears interest payable monthly at an interest rate of 3.82% and repayable by blended semi - annual principal and interest payments of $220,496, maturing July 17, 2028.

The loan payable #2 to Ontario Infrastructure and Lands Corporation was for the construction of the new administration and operation facility, bears interest at a rate of 4.61%. The loan will be repayable over 25 years by a blended monthly principal and interest payments of $118,568 and matures on October 1, 2038. The loan is secured by a mortgage on the land and building and a third ranking general security agreement .

The loan payable #3 to Ontario Infrastructure and Lands Corporation was for the construction of electric distribution infrastructure, secured by a fourth ranking general security agreement. The construction loan is expected to be converted to long term debt in 2015, repayable over 25 years by a blended monthly principal and interest payment at an interest rate to be determined. The loan is secured by a guarantee and assignment of shares from the company's shareholder, PUC Inc. and a general security agreement. The floating interest rate is determined by OILC based on OILC's cost of funds plus OILC's prevailing spread assigned to the borrower's sector for program delivery costs and risks. The average interest rate for 2014 was 1.84%.

5. Related party transactions:

The following entities are related parties of the Company:

The Corporation of the City of Sault Ste. Marie (City)	- 100% shareholder of PUC Inc.
PUC Inc. (Inc.)	- sole shareholder of the Company
PUC Services Inc. (Services)	- 100% owned by the Corporation of the City of Sault Ste. Marie
Public Utilities Commission of the City of Sault Ste. Marie (Utility)	- 100% owned by the Corporation of the City of Sault Ste. Marie

The Company has a management, operation and maintenance agreement with PUC Services Inc., which has been extended to November 30, 2017, under which Services manages, controls, administers and operates the business of the Company. Management fees were charged by Services in the amount of $4,818,382 (2013 - $5,902,657) for an allocation of joint administrative and other expenses.

The Company pays interest on its payable balance to Services at the OEB prescribed short-term borrowing rate on its average monthly balance. Interest of $237,053 (2013 - $94,644) was paid during the year.

5. Related party transactions (continued):

The Company provides electricity to the City which is the shareholder of the parent corporation, PUC Inc. Electrical energy is sold to the City at the same prices and terms as other electricity customers. The amount charged to the City for electricity consumed by streetlights is $1,679,625 (2013 - $1,544,632) and for other electricity consumption is $3,804,361 (2013 - $3,847,668).

Occupancy fees were charged by the Utility in the amount of $Nil (2013 - $98,651)

These transactions are in the normal course of operations and are measured at the exchange amount which is the amount of consideration agreed to by the related parties.

6. Contingent liability:

Purchasers of electricity in Ontario are required to provide security to the IESO to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees if PUC Distribution Inc. fails to make a payment required by a default notice issued by the IESO. In this regard, the Company has posted a letter of guarantee, secured by a first ranking general security agreement, as security in the amount of $5,000,000 underwritten by the Company's bank.

7. Income taxes:

The provision for the payment in lieu of corporate income taxes (PILs) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

Current taxes		2014		2013
Earnings before provision for payment in lieu of taxes	$	868,906	$	2,146,890
Tax at statutory rate of 26.5% (2013 - 26.5%)	$	230,260	$	568,926
Tax effect on disposition of assets		-		29,317
Amortization timing differences		(535,379)		(526,432)
Other		1,078		405
Prior year over provision		25,478		(19,491)
Provincial small business rate		-		(16,800)
	$	(278,563)	$	35,925

7. Income taxes (continued):

The tax effects of temporary differences that give rise to significant portions of the future payment in lieu of taxes are presented below utilizing the substantively enacted Federal and Ontario combined future rate of 26.5%.

Future taxes	2014	2013
Property, plant and equipment - differences in net book value and unamortized capital cost	$ 1,380,000	$ 1,940,000
Other corporate minimum tax credit	23,460	-
	$ 1,403,460	$ 1,940,000

8. Capital disclosures:

The Company's objective with respect to its capital structure is to maintain effective access to capital on an ongoing basis at reasonable rates while achieving appropriate rates of financial return for its shareholder.

The Company considers its capital structure to consist of shareholder's equity and notes payable held by the Company's shareholder which has been outlined below.

	2014	2013
Note payable to PUC Inc. - 6.1%	$ 26,534,040	$ 26,534,040
Common shares	20,062,107	20,062,107
Retained earnings	7,548,125	6,400,656
	$ 54,144,272	$ 52,996,803

The Company is subject to a shareholder's agreement which has restrictive covenants typically associated with such an agreement. At December 31, 2014, the Company is in compliance with all of the covenants and restrictions.

PUC Distribution Inc. is a Company regulated by the Ontario Energy Board. The regulator has prescribed a capital structure of 60% debt and 40% equity. For rate setting purposes the Company has complied with these requirements.

9. Credit risk and financial instruments:

(a) Financial instruments:

The carrying values of accounts receivable, payable to PUC Services Inc., customer deposits and accounts payable and accrued liabilities approximate fair value because of the short maturity of these instruments.

It is not practicable to determine the fair value of the notes payable as there are no principal repayment terms.

(b) Credit risk and concentrations of credit risk:

Financial assets held by the Company expose it to credit risk. As at December 31, 2014, there were no significant concentrations of credit risk with respect to any class of financial assets.

The Company earns its revenue from a broad base of customers located principally in Sault Ste. Marie. No single customer would account for revenue or an accounts receivable balance in excess of 10% of the respective reported balances.

(c) Interest rate risk:

The Company pays interest on its payable to PUC Services Inc. balance at the OEB prescribed short term debt rate. As a result, the Company is exposed to interest rate risk due to fluctuations in the OEB prescribed short term debt rate. These fluctuations could affect the level of interest expense of the Company.

Financial Statements of

PUC DISTRIBUTION INC.

Year ended December 31, 2015

KPMG LLP
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INDEPENDENT AUDITORS' REPORT

To the Shareholder of PUC Distribution Inc.

We have audited the accompanying financial statements of PUC Distribution Inc., which comprise the balance sheet as at December 31, 2015 and the statements of comprehensive income, changes in shareholder's 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 the 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 LLP is a Canadian limited liability partnership and a member firm of the KPMG network of independent member firms affiliated with KPMG International Cooperative ("KPMG International"), a Swiss entity.
KPMG Canada provides services to KPMG LLP.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of PUC Distribution Inc. as at December 31, 2015, and its results of operations 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 27, 2016
Sault Ste. Marie, Canada

PUC DISTRIBUTION INC.

Statements of Financial Position

As at December 31, 2015, with comparative information for 2014

	December 31, 2015	December 31, 2014	January 1, 2014
Assets			
Current assets:			
Cash and cash equivalents	$ 3,084,294	$ 4,118,664	$ 314,787
Accounts receivable (note 5)	5,900,335	7,544,347	7,886,094
Unbilled revenue	10,862,168	10,004,921	11,572,951
Due from related parties	436,883	–	–
Payment in lieu of taxes recoverable	603,021	497,819	343,139
Inventory (note 6)	1,493,197	1,614,472	1,675,485
Prepaid expenses	62,800	62,200	66,520
Total current assets	22,442,698	23,842,423	21,858,976
Non-current assets:			
Property, plant and equipment (note 7)	87,309,571	85,298,117	81,323,111
Deferred tax assets (note 8)	1,084,000	1,403,460	1,940,000
Total non-current assets	88,393,571	86,701,577	83,263,111
Total assets	110,836,269	110,544,000	105,122,087
Regulatory deferral account debit balances (note 9)	49,643	1,510,636	822,635
Deferred tax asset associated with regulatory deferral account balances	390,000	496,000	699,000
	439,643	2,006,636	1,521,635
Total assets and regulatory deferral account debit balances	$ 111,275,912	$ 112,550,636	$106,643,722

The accompanying notes are an integral part of these financial statements.

PUC DISTRIBUTION INC.

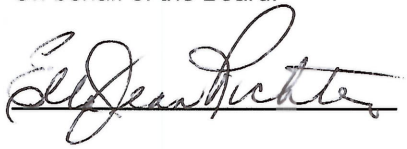
Statements of Financial Position (continued)

Year ended December 31, 2015, with comparative information for 2014

	December 31, 2015	December 31, 2014	January 1, 2014
Liabilities and Shareholder's Equity			
Current liabilities:			
Accounts payable and accrued liabilities	7,958,726	10,791,840	10,702,293
Due to related parties	–	1,945,721	8,054,961
Current portion of long-term debt (note 10)	15,785,022	15,752,049	720,470
Customer deposits (note 11)	922,422	854,761	712,536
Deferred revenue	228,455	563,782	1,227,075
Total current liabilities	24,894,625	29,908,153	21,417,335
Non-current liabilities:			
Deferred revenue	1,119,671	1,019,588	–
Long-term debt (note 10)	50,380,538	51,165,560	51,917,609
Total non-current liabilities	51,500,209	52,185,148	51,917,609
Total liabilities	76,394,834	82,093,301	73,334,944
Shareholder's equity:			
Share capital (note 12)	20,062,107	20,062,107	20,062,107
Retained earnings	8,150,941	7,262,940	6,255,769
Total shareholder's equity	28,213,048	27,325,047	26,317,876
Commitments and contingencies (note 15)			
Total liabilities and shareholder's equity	$ 104,607,882	$ 109,418,348	$ 99,652,820
Regulatory deferral account credit balances (note 9)	5,194,030	1,256,288	4,351,902
Deferred tax liability associated with regulatory deferral account balances	1,474,000	1,876,000	2,639,000
	6,668,030	3,132,288	6,990,902
Total equity, liabilities and regulatory deferral account credit balances	$ 111,275,912	$ 112,550,636	$ 106,643,722

The accompanying notes are an integral part of these financial statements.

On behalf of the Board:



Director



Director

PUC DISTRIBUTION INC.

Statement of Comprehensive Income

Year ended December 31, 2015, with comparative information for 2014

	2015	2014
Electricity sales	$ 79,708,094	$ 74,528,784
Distribution revenue	16,291,495	16,386,768
Cost of electricity sold	73,275,057	76,354,825
	22,724,532	14,560,727
Other operating revenue (note 13)	3,640,802	4,242,968
Net operating revenue	26,365,334	18,803,695
Expenses:		
Operations and maintenance	5,977,598	5,773,407
General and administrative	3,211,923	3,332,930
Billing and collection	1,417,758	1,373,301
Depreciation and amortization	4,139,746	3,896,378
Community relations	1,529,216	2,516,075
	16,276,241	16,892,091
Income from operating activities	10,089,093	1,911,604
Other expenses:		
Finance income (note 14)	26,460	7,555
Finance charges (note 14)	3,003,913	3,016,592
Net finance costs	2,977,453	3,009,037
Income (loss) before income taxes	7,111,640	(1,097,433)
Income tax expense (recovery)		
Current (note 8)	1,285,959	(278,563)
Deferred (note 8)	296,000	560,000
	1,581,959	281,437
Income (loss) for the year before movements in regulatory deferral account balances	5,529,681	(1,378,870)
Net movement in regulatory deferral account balances related to profit or loss and the related deferred tax movement	4,641,680	(2,386,041)
Net income, being total comprehensive income for the year	$ 888,001	$ 1,007,171

The accompanying notes are an integral part of these financial statements.

PUC DISTRIBUTION INC.

Statements of Changes in Shareholder's Equity

Year ended December 31, 2015, with comparative information for 2014

	Share capital	Retained earnings	Total
Balance at December 31, 2013	$ 20,062,107	$ 6,400,656	$ 26,462,763
Transitional adjustment (note 18)	–	(144,887)	(144,887)
Balance at January 1, 2014	20,062,107	6,255,769	26,317,876
Net income, being total comprehensive income	–	1,007,171	1,007,171
Balance at December 31, 2014	20,062,107	7,262,940	27,325,047
Net income, being total comprehensive income	–	888,001	888,001
Balance at December 31, 2015	$ 20,062,107	$ 8,150,941	$ 28,213,048

The accompanying notes are an integral part of these financial statements.

PUC DISTRIBUTION INC.

Statements of Cash Flows

Year ended December 31, 2015, with comparative information for 2014

	2015	2014
Cash flows from operating activities:		
Total comprehensive income for the year	$ 888,001	$ 1,007,171
Items not affecting cash:		
Depreciation and amortization	4,139,746	3,896,378
Amortization of deferred revenue	(110,389)	(99,018)
Net finance costs	2,977,453	3,009,037
Income tax expense	1,581,959	281,437
	9,476,770	8,095,005
Change in non-cash operating working capital:		
Accounts receivable	1,644,012	341,747
Unbilled revenue	(857,247)	1,568,030
Inventory	121,275	61,013
Prepaid expenses	(600)	4,320
Due from related parties	(436,883)	–
Due to related parties	(1,919,261)	(6,101,685)
Accounts payable and accrued liabilities	(2,833,114)	89,547
Customer deposits	67,661	142,225
Deferred revenue	(335,327)	(663,293)
Income tax paid	(49,428)	(199,278)
Net cash from operating activities	4,877,858	3,337,631
Cash flows from investing activities:		
Purchase of property, plant and equipment	(6,395,529)	(7,801,509)
Contributions relating to property, plant, and equipment	454,801	1,045,731
Net movements in regulatory balances	3,784,462	(4,043,914)
Net cash from investing activities	(2,156,266)	(10,799,692)
Cash flows from financing activities:		
Proceeds from long-term debt	–	15,000,000
Repayment of long -erm debt	(752,049)	(720,470)
Interest paid	(3,003,913)	(3,016,592)
Net cash from financing activities	(3,755,962)	11,262,938
Change in cash and cash equivalents	(1,034,370)	3,800,877
Cash and cash equivalents, beginning of year	4,118,664	317,787
Cash and cash equivalents, end of year	$ 3,084,294	$ 4,118,664

The accompanying notes are an integral part of these financial statements.

1. Reporting entity:

PUC Distribution Inc. (the “Company”) is a rate regulated, municipally owned hydro distribution company incorporated under the laws of Ontario, Canada. The Company is located in the City of Sault Ste. Marie. The address of the Company’s registered office is 500 Second Line East, Sault Ste. Marie, Ontario Canada.

The Company delivers electricity and related energy services to residential and commercial customers in Sault Ste. Marie. The Company is wholly owned by PUC Inc., which is itself wholly owned by The Corporation of the City of Sault Ste. Marie.

2. Basis of presentation:

(a) Statement of compliance:

The Company's financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS").

(b) Adoption of IFRS:

These are the Company’s first financial statements prepared in accordance with IFRS and IFRS1 *First-time Adoption of International Financial Reporting Standards* has been applied.

An explanation of how the transition to IFRSs has affected the reported financial position, financial performance and cash flows of the Company is provided in note 18.

(c) Approval of the financial statements:

The financial statements were approved by the Board of Directors on April 27, 2016.

(d) Basis of measurement:

The financial statements have been prepared on the historical cost basis, unless otherwise stated.

(e) Functional and presentation currency:

These financial statements are presented in Canadian dollars, which is the Company's functional currency.

(f) Use of estimates and judgments:

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 periods affected.

2. Basis of presentation (continued):

(f) Use of estimates and judgments (continued):

Information about critical judgments in applying accounting policies that have the most significant effect on the amounts recognized in these financial statements is included in the following notes:

(i) Note 7 - Property, plant and equipment
(iii) Note 15 – Commitments and contingencies

(g) Rate regulation:

The Company 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 Company, 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 Company is required to bill customers for the debt retirement charge set by the province. The Company may file to recover uncollected debt retirement charges from Ontario Electricity Financial Company ("OEFC") once each year.

Rate setting:

Distribution revenue

For the distribution revenue included in electricity sales, the Company 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 expenses, debt and shareholder's equity required to support the Company's business. The Company 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.

2. Basis of presentation (continued):

(g) Rate regulation (continued):

As a licensed distributor, the Company 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 Company is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Company ultimately collects these amounts from customers.

The Company last filed a COS application in 2012 for rates effective May 1, 2013 to April 30, 2014. The GDP IPI-FDD for 2015 is 1.6%, the Company's productivity factor is 0.0% and the stretch factor is 0.45%, resulting in a net adjustment of 1.15% 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 Company 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 and in preparing the opening IFRS statement of financial position at January 1, 2014 for the purpose of the transition to IFRS unless otherwise indicated.

(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(g). The Company 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:

Electricity sales:

Electricity sales are recognized as the electricity is delivered to customers and includes the amounts billed to customers for electricity, including the cost of electricity supplied, distribution, and any other regulatory charges. Electricity revenue is recorded on the basis of regular meter readings and estimated customer usage since the last meter reading date to the end of the year. The related cost of power is recorded on the basis of power used.

3. Significant accounting policies (continued):

(b) Revenue recognition (continued):

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 Company has determined that it is acting as a principal for these electricity charges and, therefore, has presented electricity revenue on a gross basis.

The difference between the amounts charged by the Company to customers, based on regulated rates, and the corresponding cost of electricity and related electricity service costs billed monthly by the IESO is recorded as a settlement variance. In accordance with IFRS 14, this settlement variance is presented within regulatory balances on the balance sheets and within net movements in regulatory balances, net of tax on the statement of comprehensive income.

Revenue from contracts with customers:

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 initially 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 Company'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 economic useful life of the constructed or contributed asset, which represents the period of ongoing service to the customer.

Rendering of services:

Revenue earned from the provision of services is recognized as the service is rendered.

Government grants

Incentive payments to which the Company is entitled from the Ontario Power Authority (“OPA”) are recognized as revenue in the period when they are determined by the OPA and the amount is communicated to the Company.

(c) Inventory:

Inventories consist of parts, supplies and materials held for the future capital expansion and are 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 material 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.

3. Significant accounting policies (continued):

(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, less accumulated depreciation. All other items of PP&E are measured at cost, or, where the item is transferred from customers, its fair value, less accumulated depreciation. Consistent with IFRS 1, the Company posted an adjustment to opening retained earnings to adjust for component depreciation on the transition to IFRS.

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes the cost of materials, direct labour, 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 Company's borrowings. Qualifying assets are considered to be those that take a substantial period of time to construct.

When parts of an item of property, plant and equipment have different useful lives, they are accounted for as separate items (major components) of property, plant and equipment.

Gains and losses on the disposal of an item of PP&E are determined by comparing the proceeds from disposal, if any, with the carrying amount of the item of PP&E and are recognized net within other income 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 property, plant and equipment 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 Company and its cost can be measured reliably. In this event, the replaced part of property, plant and equipment is written off, and the related gain or loss is included in profit or loss. The costs of the day-to-day servicing of property, plant and equipment are recognized in profit or loss as incurred.

Depreciation is calculated over the depreciable amount and is recognized in profit or loss on a straight-line basis over the estimated useful life of each part or component of an item of property, plant and equipment. The depreciable amount is cost. Land is not depreciated. Construction-in-progress assets are not depreciated until the project is complete and in service.

The estimated useful lives are as follows:

Buildings	25 – 50 years
Transmission and distribution	15 – 60 years
Machinery and equipment	5 – 40 years

Depreciation methods, useful lives, and residual values are reviewed at each reporting date and adjusted prospectively if appropriate.

3. Significant accounting policies (continued):

(e) Impairment:

(i) Financial assets:

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 in respect of a financial asset measured at amortized cost is calculated as the difference between its current carrying amount (using prevailing interest rates), 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.

All impairment losses are recognized in profit or loss. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in profit or loss.

(ii) Non-financial assets:

The carrying amounts of the Company's non-financial assets, other than inventories 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"). The recoverable amount of an asset or cash-generating unit 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 cash-generating unit exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss.

Impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. 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, if no impairment loss had been recognized.

3. Significant accounting policies (continued):

(f) Provisions:

A provision is recognized if, as a result of a past event, the Company 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.

(g) Regulatory deferral accounts:

Regulatory deferral account debit balances represent costs incurred in excess of amounts billed to the customer at OEB approved rates. These amounts have been accumulated and deferred in anticipation of their future recovery in electricity distribution rates. Regulatory deferral account credit balances represent amounts billed to the customer at OEB approved rates in excess of costs incurred by the Company.

Regulatory deferral account debit balances are recognized if it is probable that future billings in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes. The offsetting amount is recognized in profit and loss. The debit balance is reduced by the amount of customer billings as electricity is delivered to the customer and the customer is billed at rates approved by the OEB for the recovery of the capitalized costs.

Regulatory deferral account credit balances are recognized if it is probable that future billings in an amount at least equal to the credit balance will be reduced as a result of rate-making activities. The offsetting amount is recognized in profit and loss. The credit balance is reduced by the amounts returned to customers as electricity is delivered to the customer at rates approved by the OEB for the return of the regulatory account credit balance.

The probability of recovery or repayment of the regulatory account balances are assess annually based upon the likelihood that the OEB will approve the change in rates to recover or repay the balance. Any resulting impairment loss is recognized in profit and loss in the year incurred.

Regulatory deferral accounts attract interest at OEB prescribed rates. In 2015 the rate was 1.2%.

(h) Credit support for service delivery:

Credit support for service delivery represents cash deposits from electricity distribution customers as well as construction deposits.

Deposits from electricity distribution customers are applied against any unpaid portion of individual customer accounts. Customer deposits in excess of unpaid account balances are refundable to individual customers upon termination of their electricity distribution service. Customer deposits are also refundable to residential electricity distribution customers demonstrating an acceptable level of credit risk, as determined by the Company.

3. Significant accounting policies (continued):

(h) Credit support for service delivery (continued):

Certain customers and developers are required to contribute towards the capital cost of construction in order to provide ongoing service. Cash contributions are initially recorded as credit support for service delivery, a current liability. Once the distribution system asset is completed or modified as outlined in the terms of the contract, the contribution amount is transferred to deferred revenue.

(i) Deferred revenue and assets transferred from customers:

Certain customers and developers are required to contribute towards the capital cost of construction in order to provide ongoing service. When an asset is received as a capital contribution, the asset is initially recognized at its fair value, with the corresponding amount recognized as deferred revenue. Deferred revenue represents the Company's obligation to continue to provide customers access to the supply of electricity, and is amortized to income on a straight-line basis over the economic useful life of the acquired or contributed asset, which represents the period of ongoing service to the customer.

(j) 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 and on regulatory assets.

Finance charges comprise interest expense on borrowings. Finance costs are recognized as an expense unless they are capitalized as part of the cost of qualifying assets.

(k) Payment in lieu of taxes:

The Company 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 Company makes payments in lieu of corporate taxes to the Ontario Electricity Financial Company ("OEFC"). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Company's Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations. Prior to October 1, 2001, the Company was not subject to income or capital taxes.

PILs comprises current and deferred payments in lieu of income tax. PILs recognized in income and loss except to the extent that it relates to items recognized directly in either comprehensive income or equity, in which case, it is recognized in comprehensive income or in equity.

Current PILS is the expected amount of tax payable on the taxable income 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 PILs comprise the net tax effects of temporary differences between the tax basis of assets and liabilities and their respective carrying amounts for accounting purposes, as well as for tax losses available to be carried forward to future years that are likely to be realized.

3. Significant accounting policies (continued):

(k) Payment in lieu of taxes (continued):

Deferred PILs assets and liabilities are measured using enacted or substantively enacted tax rates, at the reporting date, expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred PILs assets and liabilities of a change in tax rates is recognized in income in the year that includes the date of enactment or substantive enactment.

A deferred PILs asset is recognized to the extent that it is probable that future taxable income will be available against which the temporary difference can be utilized. Deferred PILs assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

(l) New standards and interpretations not yet effective:

The following new standards and interpretations are not yet effective but are considered to be relevant to the Company's financial statements:

i) IFRS 15 *Revenue from Contracts with Customers*

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 Company is assessing the impact of IFRS 15 on its results of operations, financial position and disclosures.

ii) IFRS 9 Financial Instruments ("IFRS 9"(2014))

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 multiphase 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 periods beginning on or after January 1, 2018 and must be applied retrospectively. The Company is assessing the impact of IFRS 9 on its results of operations, financial position, and disclosures.

iii) IFRS 16 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 Company is assessing the impact of IFRS 16 on its results of operations, financial position and disclosures.

3. Significant accounting policies (continued):

(l) New standards and interpretations not yet effective (continued):

iv) IAS 16 and IAS 38 *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 Company does not expect this to have an impact on its results of operations, financial position and disclosures.

4. Critical accounting estimates and judgments:

The Company makes estimates and assumptions about the future that affect the reported amounts of assets and liabilities. Estimates and judgments are continually evaluated based on historical experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. In the future, actual experience may differ from these estimates and assumptions.

The effect of a change in an accounting estimate is recognized prospectively by including it in comprehensive income in the period of the change, if the change affects that period only; or in the period of the change and future periods, if the change affects both.

The estimates and assumptions that have a significant risk of causing material adjustment to the carrying amounts of assets and liabilities within the next financial year are discussed below.

Fair value of financial instruments:

The Company determines the fair value of financial instruments that are not quoted in an active market, using valuation techniques. Those techniques are significantly affected by the assumptions used, including discount rates and estimates of future cash flows. In that regard, the derived fair value estimates cannot always be substantiated by comparison with independent markets and, in many cases, may not be capable of being realized immediately.

The methods, and assumptions applied, and the valuation techniques used, for financial instruments that are not quoted in an active market are disclosed in note 23.

Payment in lieu of taxes:

The Company periodically assesses its liabilities and contingencies related to PILs for all years open to audit based on the latest information available. For matters where it is probable that an adjustment will be made, the Company records its best estimate of the tax liability including the related interest and penalties in the current PILs provision. Management believes they have adequately provided for the probable outcome of these matters; however, the final outcome may result in a materially different outcome that the amount included in the PILs liabilities.

4. Critical accounting estimates and judgments (continued):

Useful lives of depreciable assets:

Management reviews the useful lives of depreciable assets at each reporting date. At December 31, 2015, management assesses that the useful lives represent the expected utility of the assets to the Company. The carrying amounts are analyzed in notes 13 and 14. Actual results, however, may vary due to technical obsolescence, particularly for software and electronic equipment.

Impairment:

An impairment loss is recognized for the amount by which an asset's carrying amount exceeds its recoverable amount, which is the higher of fair value less cost to sell and value-in-use. To determine the value-in-use, management estimates expected future cash flows from each asset or cash generating unit and determines a suitable interest rate in order to calculate the present value of those cash flows. In most cases, determining the applicable discount rate involves estimating the appropriate adjustment to market risk and the appropriate adjustment to asset-specific risk factors. In the process of measuring expected future cash flows management makes assumptions about future operating results. These assumptions relate to future events and circumstances.

5. Accounts receivable:

	December 31, 2015	December 31, 2014	January 1, 2014
Trade receivables	$ 5,664,419	$ 7,331,531	$ 5,743,189
Other receivables	235,916	212,816	2,142,905
	$ 5,900,335	$ 7,544,347	$ 7,886,094

6. Inventory:

The amount of inventories consumed by the Company and recognized as an expense during 2015 was $260,058 (2014 - $341,122).

	2015	2014
Stores	$ 761,951	$ 774,356
Wire and cable	502,375	576,351
Poles	228,871	263,765
	$ 1,493,197	$ 1,614,472

7. Property, plant and equipment:

(a) Cost or deemed cost:

	Land and buildings	Transmission & distribution	Plant & equipment	Construction -in- Progress	Total
Balance at January 1, 2015	$ 25,804,561	$46,995,627	$16,161,153	$ –	$ 88,961,341
Additions	72,224	5,668,676	969,792	–	6,710,692
Transfers	–	–	–	–	–
Disposals/retirements	–	(352,311)	(287,603)	–	(639,914)
Balance at December 31, 2015	$ 25,876,785	$52,311,992	$16,843,342	$ –	$ 95,032,119

	Land and buildings	Transmission & distribution	Plant & equipment	Construction -in- Progress	Total
Balance at January 1, 2014	$ 25,579,334	$41,560,173	$14,176,816	$ 6,788	$ 81,323,111
Additions	251,652	5,435,454	2,012,886	–	7,699,992
Transfers	–	–	6,788	(6,788)	–
Disposals/retirements	(26,425)	–	(35,337)	–	(61,762)
Balance at December 31, 2014	$ 25,804,561	$46,995,627	$16,161,153	$ –	$ 88,961,341

(b) Accumulated depreciation:

	Land and buildings	Transmission & distribution	Plant & equipment	Construction -in- Progress	Total
Balance at January 1, 2015	$ 641,821	$ 2,337,387	$ 684,016	$ –	$ 3,663,224
Depreciation charge	662,844	2,949,074	845,032	–	4,456,950
Disposals/retirements	(793)	(66,630)	(330,203)	–	(397,626)
Balance at December 31, 2015	$ 1,303,872	$ 5,219,831	$ 1,198,845	$ –	$ 7,722,548

	Land and buildings	Transmission & distribution	Plant & equipment	Construction -in- Progress	Total
Balance at January 1, 2014	$ –	$ –	$ –	$ –	$ –
Depreciation charge	661,571	2,337,387	897,420	–	3,896,378
Disposals/retirements	(19,750)	–	(213,404)	–	(233,154)
Balance at December 31, 2014	$ 641,821	$ 2,337,387	$ 684,016	$ –	$ 3,663,224

7. Property, plant and equipment (continued):

(c) Carrying amounts:

	Land and buildings	Transmission & distribution	Plant & equipment	Construction -in- Progress	Total
At December 31, 2015	$ 24,572,914	$ 47,092,160	$15,644,497	$ –	$87,309,571
At December 31, 2014	25,162,740	44,658,240	15,477,137	–	85,298,117
At January 1, 2014	25,579,334	41,560,173	14,176,816	6,788	81,323,111

(e) Security:

At December 31, 2015 properties with a carrying amount of $87,309,571 (2014 - $85,298,117) are subject to a general security agreement.

8. Payments in lieu of income taxes:

Payment in lieu of taxes:

	2015	2014
Current	$ 1,285,959	$ (278,563)
Deferred	296,000	560,000
Income tax expense	$ 1,581,959	$ 281,437

Reconciliation of effective tax rate:

	2015	2014
Earnings before payments in lieu of income taxes	$ 7,111,640	$ 1,007,171
Statutory rate	26.5%	26.5%
Profit excluding income tax	1,884,585	266,900
Increase (decrease) resulting from:		
Permanent difference	838	539
Change in regulatory accounts impacting current tax	(296,000)	–
Other	(7,464)	13,998
	$ 1,581,959	$ 281,437

9. Regulatory deferral account balance:

The following is a reconciliation of the carrying amount for each class of regulatory deferral account balances:

	2014	Balances arising in the period	Recovery/ reversal	2015	Remaining recovery/ reversal period (years)
Regulatory deferral account debit balances					
Regulatory Asset recovery Account Phase 6	$ 30,036	$ 1,823	$ (9,872)	$ 21,987	<1
Future taxes	496,000	–	(106,000)	390,000	
Stranded Meters	4,015	(65)	(42)	3,908	<1
Smart Meter Entity Charges	23,889	312,113	(312,254)	23,748	3
Total amount related to regulatory deferral account debit balances	$ 553,940	$ 313,871	$(428,168)	$ 439,643	

	2014	Balances arising in the period	Recovery/ reversal	2015	Remaining recovery/ reversal period (years)
Regulatory deferral account credit balances					
Settlement Variance	$ 1,415,937	$ (6,437,792)	$ –	$(5,021,855)	<1
Future Taxes	(1,876,000)	–	402,000	(1,474,000)	
Regulatory Asset Recovery Account Phase 5	(29,584)	(297)	(663)	(30,544)	<1
Regulatory Asset Recovery Account Phase 7	(1,080,954)	(3,756)	1,026,308	(58,402)	<1
CGAAP Accounting Changes	(145,750)	72,876	–	(72,874)	1
LRAMVA	36,758	34	(47,147)	(10,355)	<1
Total amount related to regulatory deferral account credit balances	$ (1,679,593)	$ (6,368,935)	$1,380,498	$(6,668,030)	

The regulatory deferral account balances are recovered or settled through rates set 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 Company has received approval from the OEB to establish its regulatory deferral account 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 $1,469,174 of the Group 1 deferral accounts. Once approval is received, the approved account balance is moved to the regulatory settlement account. The OEB requires the Company to estimate its income taxes when it files a COS application to set its rates. As a result, the Company 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 Company's deferred tax balance fluctuates.

10. Long-term debt:

	2015	2014
Notes payable:		
(i) Ontario Infrastructure smart meter loan	$ 4,485,507	$ 4,747,620
(ii) Ontario Infrastructure building loan	20,146,013	20,635,949
(iii) Ontario Infrastructure construction loan	15,000,000	15,000,000
(iv) Note payable to parent company, PUC Inc.	26,534,040	26,534,040
	66,165,560	66,917,609
Current portion of long-term debt	15,785,022	15,752,049
	$ 50,380,538	$ 51,165,560

i) Smart Meter Loan with Ontario Infrastructure and Lands Corporation (OILC): Reducing Debenture Facility, amortization period of 15 years to July 17, 2028. The loan interest rate of 3.82%. Interest of $174,708 (2014 - $176,528) was paid and expensed during the year. The loan is payable in the amount of $220,496 semi-annual principal and interest. Security is in the form of a second ranking general security agreement.

ii) Land and Building Loan with OILC: Reducing Debenture Facility, amortization period of 25 years to October 1, 2038. The loan interest rate of 4.61%. Interest of $932,885 (2014 - $954,731) was paid and expensed during the year. The loan is payable in the amount of $118,568 monthly principal and interest. Security is in the form of a first charge over the Company's land and building and a third ranking general security agreement.

iii) Electric Distribution Infrastructure Loan with OILC: Construction loan is expected to be converted to long term debt in 2016, repayable over 25 years by a blended monthly principal and interest payment at an interest rate to be determined. The floating interest rate is determined by the OILC based on OILC's prevailing spread assigned to the borrower's sector for program delivery costs and risks. The average interest rate for 2015 was 1.55%. Interest of $212,884 (2014 - $6,822) was paid and expensed during the year. Security is in the form of a fourth ranking general security agreement and a guarantee and assignment of shares from the company's shareholder, PUC Inc.

iv) Note payable to parent company, PUC Inc., bears interest payable quarterly at rates periodically negotiated and principal payable one year after demand. The average interest rate for 2015 was 6.1% (2014 – 6.1%). The balance outstanding for 2015 is $26,534,040 (2014 - $26,534,040).

10. Long-term debt (continued):

Principal payments on the long-term debt are as follows:

2016	$ 15,785,022
2017	819,453
2018	855,405
2019	892,946
2020	932,148
2021 - 2035	46,880,586
	66,165,560
Less: current portion	(15,785,022)
Long-term portion of loan	$ 50,380,538

11. Customer deposits:

Customer deposits represent cash deposits from electricity distribution customers and retailers, as well as construction deposits.

Deposits from electricity distribution customers are refundable to customers who demonstrate an acceptable level of credit risk as determined by the Company in accordance with policies set out by the OEB or upon termination of their electricity distribution service. The balance at December 31, 2015 is $922,422 (2014 - $854,761).

12. Share capital:

	2015	2014
Authorized:		
Unlimited number of special shares, non-voting, non-cumulative		
Redeemable at $10,000 per share		
10,000 Common shares		
Issued and outstaning:		
8,612 common shares	$ 20,062,107	$ 20,062,107

13. Other operating revenue:

Other income comprises:

	2015	2014
Rendering of services	$ 3,381,383	$ 3,995,623
Other	149,030	148,327
Amortization of deferred revenue	110,389	99,018
Total other income	$ 3,640,802	$ 4,242,968

14. Finance income and expense:

	2015	2014
Interest income	$ 26,460	$ 7,555
Finance income	26,460	7,555
Interest expense on long-term debt	2,939,100	2,756,657
Other interest and carrying charges	64,813	259,935
	3,003,913	3,016,592
Net finance costs recognized in profit or loss	$ 2,977,453	$ 3,009,037

15. Commitments and contingencies:

General:

From time to time, the Company is involved in various litigation matters arising in the ordinary course of its business. The Company 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 Company's financial position, results of operations or its ability to carry on any of its business activities.

General Liability Insurance:

The Company 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.

16. Related party transactions:

(a) Parent, ultimate controlling party, and other related parties:

The sole shareholder of the Company is PUC Inc., which in turn is wholly-owned by the Corporation of the City of Sault Ste. Marie. The City produces financial statements that are available for public use. Other related parties include PUC Services Inc. (Services), and Public Utilities Commission of the City of Sault Ste. Marie (Utility).

(b) Key management personnel:

The key management personnel of the Company have been defined as members of its board of directors and is summarized below.

	2015	2014
Directors' fees	$ 9,756	$ 8,582

(c) Transactions with ultimate parent (the City):

In the year, the Company had the following significant transactions with its ultimate parent, a government entity:

The Company delivers electricity to the City throughout the year for the electricity needs of the City and its related organizations. Electricity delivery charges are at prices and under terms approved by the OEB. The amount charged to the City for electricity consumed by streetlights is $1,718,602 (2014 - $1,679,625) and for other electricity consumption is $3,668,401 (2014 - $3,804,361).

(d) Transactions with Services:

The Company has a management, operation and maintenance agreement with Services, which has been extended to November 30, 2017, under which Services manages, controls, administers and operates the business of the Company. During the year, management fees were paid to Services in the amount of $4,871,691 (2014 - $4,818,382).

The Company receives/(pays) interest on its receivable/payable balance to Services at the OEB prescribed short-term borrowing rate on its average monthly balance. Interest of $7,221 (2014 - $(237,053)) was received/(paid) during the year.

These transactions are in the normal course of operations and are measure at the exchange amount which is the amount of consideration agreed to by the related parties.

17. Financial instruments and risk management:

Fair value disclosure

Cash and cash equivalents are measured at fair value. The carrying values of receivables, and accounts payable and accrued charges 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.

Financial risks

The Company understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Company'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 Company, such as accounts receivable, expose it to credit risk. The Company earns its revenue from a broad base of customers located in the City. No single customer accounts for a balance in excess of 2.53% 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 net income. Subsequent recoveries of receivables previously provisioned are credited to net income. The balance of the allowance for impairment at December 31, 2015 is $100,000 (2014 - $100,000).

The Company's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2015, approximately $782,396 (2014 - $1,326,525) is considered 60 days past due. The Company has over 33 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 Company holds security deposits in the amount of $922,422 (2014 - $854,761).

(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 Company currently does not have any material commodity or foreign exchange risk. The Company is exposed to fluctuations in interest rates as the regulated rate of return for the Company'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.

17. Financial instruments and risk management (continued):

(c) Liquidity risk:

The Company monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Company's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest exposure. The Company monitors cash balances daily to ensure that a sufficient level of liquidity is on hand to meet financial commitments as they come due. As at December 31, 2015, no amounts had been drawn under the Company's credit facilities.

The majority of accounts payable, as reported on the balance sheet, are due within 30 days.

(d) Capital disclosures:

The main objectives of the Company, 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 Company's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2015, shareholder's equity amounts to $28,213,048 (2014 - $27,325,047) and long-term debt amounts to $66,165,560 (2014 - $66,917,609).

18. Explanation of transition to IFRS:

As stated in note 2(b), these are the Company'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 an opening IFRS Statement of Financial Position as at January 1, 2014 (the Company's date of transition).

In preparing its opening IFRS Statement of Financial Position, the Company has adjusted the amounts reported previously in 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 Company's financial position, financial performance and cash flows is set out in the following table and the notes accompanying the tables.

IFRS 1 Exemptions

IFRS 1 sets out the procedures that the Company must follow when it adopts IFRS for the first time as the basis for preparing its financial statements. The Company 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 Company.

Regulatory deferral accounts

IFRS14: *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: a) conducts rate-regulated activities; and b) 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 IAS8: *Accounting policies, changes in accounting estimates and errors*, to its accounting policies for the recognition, measurement, impairment and derecognition of regulatory deferral account balances.

18. Explanation of transition to IFRS (continued):

Reconciliation of statement of financial position and statement of changes in equity January 1, 2014

Account	Note	C-GAAP	Presentation differences	Measurement and recognition differences	IFRS
Cash and cash equivalents		314,787	-	-	314,787
Accounts receivable		7,886,094	-	-	7,886,094
Unbilled revenue		11,572,951	-	-	11,572,951
Inventory		1,675,485	-	-	1,675,485
Prepaid expenses		66,520	-	-	66,520
PIL of taxes recoverable		343,139	-	-	343,139
Current portion of regulatory assets	(b)	771,711	(771,711)	-	-
Property, plant and equipment	(a), (c)	81,467,998	-	(144,887)	81,323,111
Regulatory assets	(b)	50,924	(50,924)	-	-
Deferred tax assets		1,940,000	-	-	1,940,000
Total assets		106,089,609	(822,635)	(144,887)	105,122,087
Regulatory deferral account debit balances	(b)	-	822,635	-	822,635
Deferred tax asset associated with regulatory deferral account balances	(b)		699,000		699,000
Total assets and regulatory deferral account debit balances		106,089,609	699,000	(144,887)	106,643,722
Accounts payable and accrued liabilities		10,702,293	-	-	10,702,293
Deferred revenue		1,227,075	-	-	1,227,075
Current regulatory liabilities	(b)	3,053,420	(3,053,420)	-	-
Due to related parties		8,054,961	-	-	8,054,961
Current long-term debt		720,470	-	-	720,470
Long term debt		51,917,609	-	-	51,917,609
Customer deposits		712,536	-	-	712,536
Regulatory liabilities	(b)	3,238,482	(3,238,482)	-	-
Total liabilities		79,629,846	(6,291,902)	-	73,334,944
Share capital		20,062,107	-	-	20,062,107
Retained earnings	(a)	6,400,656	-	(144,887)	6,255,769
Total liabilities and shareholder's equity		106,089,609	(6,291,902)	(144,887)	99,652,820
Regulatory deferral account credit-balances	(b)	-	4,351,902	-	4,351,902
Deferred tax liability associated with regulatory deferral account balances	(b)	-	2,639,000	-	2,639,000
Total equity, liabilities and regulatory deferral account credit balances		106,089,609	699,000	(144,887)	106,643,722

18. Explanation of transition to IFRS (continued):

Reconciliation of statement of financial position and statement of changes in equity

December 31, 2014

Account	Note	C-GAAP	Presentation differences	Measurement and recognition differences	IFRS
Cash and cash equivalents		4,118,664	-	-	4,118,664
Accounts receivable		7,544,347	-	-	7,544,347
Unbilled revenue		10,004,921	-	-	10,004,921
Inventory		1,614,472	-	-	1,614,472
Prepaid expenses		62,200	-	-	62,200
PIL of taxes recoverable		497,819	-	-	497,819
Current portion of regulatory assets	(b)	28,521	(28,521)	-	-
Property, plant and equipment	(a), (c)	84,563,714	1,109,588	(285,185)	85,388,117
Regulatory assets	(b)	1,482,115	(1,482,115)	-	-
Deferred tax assets		1,403,460	-	-	1,403,460
Total assets	(a)	111,320,233	(401,048)	(285,185)	112,550,636
Regulatory deferral account debit balances	(b)		1,510,636	-	1,510,636
Deferred tax asset associated with regulatory deferral account balances	(b)		496,000		496,000
Total assets and regulatory deferral account debit balances		111,320,233	1,605,588	(285,185)	112,550,636
Accounts payable and accrued liabilities		10,791,840	-	-	10,791,840
Deferred revenue		563,782	-	-	563,782
Current regulatory liabilities	(b)	1,153,830	(1,153,830)	-	-
Due to related parties		1,945,721	-	-	1,945,721
Current long-term debt		15,752,049	-	-	15,752,049
Long term debt		51,165,560	-	-	51,165,560
Customer deposits		854,761	-	-	854,761
Deferred revenue	(c)		1,109,588	-	1,109,588
Regulatory liabilities	(b)	1,482,458	(1,482,458)	-	-
Total liabilities		83,710,001	(1,526,700)		82,093,301
Share capital		20,062,107	-	-	20,062,107
Retained earnings	(a)	7,548,125	-	(285,185)	7,262,940
Total liabilities and shareholder's equity		111,320,233	(1,933,905)	(285,185)	109,101,143
Regulatory deferral account credit-balances	(b)	-	1,256,288	-	1,256,288
Deferred tax liability associated with regulatory deferral account balances	(b)		1,876,000		1,876,000
Total equity, liabilities and regulatory deferral account credit balances		111,320,233	1,605,588	(285,185)	112,550,636

18. Explanation of transition to IFRS (continued):

Reconciliation of net income for 2014

Account	Note	C-GAAP	Presentation differences	Measurement and recognition differences	IFRS
Electricity sales	(b)	70,473,134	4,055,650	-	74,528,784
Distribution revenue		16,386,768	-	-	16,386,768
Other related charges	(d)	148,327	(148,327)	-	-
Other	(d)	3,995,623	(3,995,623)	-	-
		91,003,852	(88,300)	-	90,915,552
Cost of electricity sold	(b)	(70,473,134)	(5,881,691)	-	(76,354,825)
		20,530,718	(5,969,911)	-	14,560,727
Investment income	(d)	7,555	(7,555)	-	-
Other operating revenue	(c), (d)	-	4,242,968	-	4,242,968
Net operating revenue		20,538,273	(1,806,792)	-	18,803,696
Operations and maintenance expense		5,773,407	-	-	5,773,407
General and administrative expense		3,332,931	-	-	3,332,931
Interest on long-term debt	(d)	2,756,657	(2,756,657)	-	-
Billing and collection expense		1,373,301	-	-	1,373,301
Depreciation of property, plant and equipment	(a), (c)	3,657,061	99,019	140,298	3,896,378
Community relations		2,516,075	-	-	2,516,075
Other costs	(d)	259,935	(259,935)	-	-
Total expenses		19,669,367	(2,917,574)	140,298	16,892,091
Net income from operating activities		868,906	1,182,996	(140,298)	1,911,604
Finance income	(d)	-	7,555	-	7,555
Finance charges	(d)	-	3,016,592	-	3,016,592
Income tax (recovery)		(278,563)	-	-	(278,563)
Deferred tax	(b)	-	560,000	-	560,000
Income (loss) for the year before movements in regulatory deferral account balances		1,147,469	(2,386,041)	(140,298)	(1,378,870)
Net movement in regulatory deferral account balances	(b)	-	2,386,041	-	2,386,041
Income (loss) for the year and net movements in regulatory deferral account balances, being total comprehensive income (loss) for the year		1,147,469	-	(140,298)	1,007,171

18. 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) Transition to IFRS triggered the Company to componentize their newly constructed building. The effect of this transitional adjustment is an increase of $144,887 to the previous CGAAP accumulated depreciation of the affected PP&E assets at January 1, 2014, which is recognized as an adjustment to opening retained earnings. An additional $140,298 was recognized in depreciation expense and accumulated depreciation for the year ended December 31, 2014.

(b) IFRS 14 permits a rate-regulated entity to continue to apply its previous GAAP accounting policies for the recognition and measurement of regulatory balances. However, all regulatory balances and related deferred tax amounts are reclassified to a new and separate section of the balance sheet. As well the net income effect of all changes in regulatory balances must be segregated in a new separate section of the statement of income. The effect of the reclassifications would enhance comparability to IFRS 14 compliant financial statements with those of entities not applying IFRS 14.

(c) Under CGAAP, capital contributions were netted against the cost of PP&E and amortized to net income as an offset to depreciation expense, on the same basis as the related assets. Under IFRS, capital contributions are recognized initially as customer deposits until the related asset is constructed, at which time the capital contributions are recognized as deferred revenue and amortized into net income over the life of the related asset.

At December 31, 2014, the effect is to increase PP&E by $1,109,588, increase deferred revenue by $1,109,588and increase other revenue by $99,019 for the year ended December 31, 2014.

(d) Certain amounts have been reclassified to conform to the financial statement presentation adopted for 2015.

(e) The above changes increase the deferred tax asset as follows based on a tax rate of 26.5%:

	December 31, 2014	January 1, 2014
Property, plant and equipment	$ 38,395	$ 37,179
Increase in deferred tax asset	$ 38,395	$ 37,179

(f) 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 IRFSs and the statement of cash flows presented under CGAAP.

Financial Statements of

PUC DISTRIBUTION INC.

Year ended December 31, 2016

KPMG LLP
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INDEPENDENT AUDITORS' REPORT

To the Shareholder of PUC Distribution Inc.

We have audited the accompanying financial statements of PUC Distribution Inc., which comprise the statement of financial position as at December 31, 2016 and the statements of comprehensive income, changes in shareholder's 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 the 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 LLP is a Canadian limited liability partnership and a member firm of the KPMG network of independent member firms affiliated with KPMG International Cooperative ("KPMG International"), a Swiss entity. KPMG Canada provides services to KPMG LLP.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of PUC Distribution Inc. as at December 31, 2016, and its results of operations 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 26, 2017
Sault Ste. Marie, Canada

PUC DISTRIBUTION INC.

Statement of Financial Position

As at December 31, 2016, with comparative information for 2015

	2016	2015
Assets		
Current assets:		
Cash and cash equivalents	$ 3,899,721	$ 3,084,294
Accounts receivable (note 5)	6,620,270	5,900,335
Unbilled revenue	10,175,782	10,862,168
Due from related parties	100,201	436,883
Payment in lieu of taxes recoverable	550,032	603,021
Inventory (note 6)	1,486,453	1,493,197
Prepaid expenses	63,400	62,800
Total current assets	22,895,859	22,442,698
Non-current assets:		
Property, plant and equipment (note 7)	89,413,226	87,626,775
Deferred tax assets (note 8)	1,081,000	1,084,000
Total non-current assets	90,494,226	88,710,775
Total assets	113,390,085	111,153,473
Regulatory deferral account debit balances (note 9)	698,439	49,643
Deferred tax asset associated with regulatory deferral account balances (note 9)	390,000	390,000
	1,088,439	439,643
Total assets and regulatory deferral account debit balances	$ 114,478,524	$ 111,593,116

The accompanying notes are an integral part of these financial statements.

PUC DISTRIBUTION INC.

Statement of Financial Position (continued)

Year ended December 31, 2016, with comparative information for 2015

	2016	2015
Liabilities and Shareholder's Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 13,766,613	7,958,725
Current portion of long-term debt (note 10)	1,211,084	15,785,022
Customer deposits (note 11)	987,485	922,422
Deferred revenue	207,980	228,455
Total current liabilities	16,173,162	24,894,624
Non-current liabilities:		
Deferred revenue	1,847,591	1,436,876
Long-term debt (note 10)	63,947,191	50,380,538
Total non-current liabilities	65,794,782	51,817,414
Total liabilities	81,967,944	76,712,038
Shareholder's equity:		
Share capital (note 12)	20,062,107	20,062,107
Retained earnings	7,830,504	8,150,941
Total shareholder's equity	27,892,611	28,213,048
Total liabilities and shareholder's equity	109,860,555	104,925,086
Regulatory deferral account credit balances (note 9)	3,146,969	5,194,030
Deferred tax liability associated with regulatory deferral account balances	1,471,000	1,474,000
	4,617,969	6,668,030
Commitments and contingencies (note 15)		
Total equity, liabilities and regulatory deferral account credit balances	$ 114,478,524	$ 111,593,116

The accompanying notes are an integral part of these financial statements.

On behalf of the Board:

Director

Director

PUC DISTRIBUTION INC.

Statement of Comprehensive Income

Year ended December 31, 2016, with comparative information for 2015

	2016	2015
Electricity sales	$ 82,764,200	$ 79,708,094
Distribution revenue	15,495,940	16,291,495
Cost of electricity sold	(81,410,411)	(73,275,057)
	16,849,729	22,724,532
Other operating revenue (note 13)	3,493,755	3,640,802
Net operating revenue	20,343,484	26,365,334
Expenses:		
Operations and maintenance	5,977,871	5,977,598
General and administrative	3,188,235	3,211,923
Billing and collection	1,572,173	1,417,758
Depreciation and amortization	4,202,174	4,139,746
Community relations	1,388,930	1,529,216
	16,329,383	16,276,241
Income from operating activities	4,014,101	10,089,093
Other expenses:		
Finance income (note 14)	33,313	26,460
Finance charges (note 14)	3,058,063	3,003,913
Net finance costs	3,024,750	2,977,453
Income before income taxes	989,351	7,111,640
Income tax expense (recovery)		
Current (note 8)	(44,000)	1,285,959
Deferred (note 8)	3,000	296,000
	(41,000)	1,581,959
Income for the year before movements in regulatory deferral account balances	1,030,351	5,529,681
Net movement in regulatory deferral account balances related to profit or loss	1,353,788	6,433,037
Income tax	3,000	1,791,357
	1,350,788	4,641,680
Net (loss) income, being total comprehensive (loss) income for the year	$ (320,437)	$ 888,001

The accompanying notes are an integral part of these financial statements.

PUC DISTRIBUTION INC.

Statements of Changes in Shareholder's Equity

Year ended December 31, 2016, with comparative information for 2015

	Share capital	Retained earnings	Total
Balance at December 31, 2014	$ 20,062,107	$ 7,262,940	$ 27,325,047
Net income, being total comprehensive income	–	888,001	888,001
Balance at December 31, 2015	$ 20,062,107	$ 8,150,941	$ 28,213,048
Net loss, being total comprehensive (loss)	–	(320,437)	(320,437)
Balance at December 31, 2016	$ 20,062,107	$ 7,830,504	$ 27,892,611

The accompanying notes are an integral part of these financial statements.

PUC DISTRIBUTION INC.

Statements of Cash Flows

Year ended December 31, 2016, with comparative information for 2015

	2016	2015
Cash flows from operating activities:		
Total comprehensive (loss) income for the year	$ (320,437)	$ 888,001
Items not affecting cash:		
Depreciation and amortization	4,202,174	4,139,746
Amortization of deferred revenue	(112,433)	(110,389)
Net finance costs	3,024,750	2,977,453
Income tax expense (recovery)	(41,000)	1,581,959
	6,753,054	9,476,770
Change in non-cash operating working capital:		
Accounts receivable	(719,935)	1,644,012
Unbilled revenue	686,386	(857,247)
Inventory	6,744	121,275
Prepaid expenses	(600)	(600)
Due from related parties	336,682	(436,883)
Due to related parties	–	(1,919,261)
Accounts payable and accrued liabilities	5,807,888	(2,833,114)
Customer deposits	65,063	67,661
Deferred revenue	(20,475)	(335,327)
Income tax paid	114,250	(49,428)
Net movements in regulatory balances	(2,609,928)	3,784,462
Net cash from operating activities	10,419,129	8,662,320
Cash flows from investing activities:		
Purchase of property, plant and equipment	(5,988,626)	(6,395,529)
Contributions relating to property, plant, and equipment	450,272	454,801
Net cash from investing activities	(5,538,354)	(5,940,728)
Cash flows from financing activities:		
Repayment of long-term debt	(1,007,285)	(752,049)
Interest paid	(3,058,063)	(3,003,913)
Net cash from financing activities	(4,065,348)	(3,755,962)
Change in cash and cash equivalents	815,427	(1,034,370)
Cash and cash equivalents, beginning of year	3,084,294	4,118,664
Cash and cash equivalents, end of year	$ 3,899,721	$ 3,084,294

The accompanying notes are an integral part of these financial statements.

1. Reporting entity:

PUC Distribution Inc. (the “Company”) is a rate regulated, municipally owned hydro distribution company incorporated under the laws of Ontario, Canada. The Company is located in the City of Sault Ste. Marie. The address of the Company’s registered office is 500 Second Line East, Sault Ste. Marie, Ontario Canada.

The Company delivers electricity and related energy services to residential and commercial customers in Sault Ste. Marie. The Company is wholly owned by PUC Inc., which is itself wholly owned by The Corporation of the City of Sault Ste. Marie.

2. Basis of presentation:

(a) Statement of compliance:

The Company's financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS").

(b) Approval of the financial statements:

The financial statements were approved by the Board of Directors on April 26, 2017.

(c) Basis of measurement:

The 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 Company's functional currency.

(e) Use of estimates and judgments:

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 periods affected.

2. Basis of presentation (continued):

(e) Use of estimates and judgments (continued):

Information about critical judgments in applying accounting policies that have the most significant effect on the amounts recognized in these financial statements is included in the following notes:

(i) Note 7 - Property, plant and equipment
(iii) Note 15 – Commitments and contingencies

(f) Rate regulation:

The Company 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 Company, 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 Company is required to bill customers for the debt retirement charge set by the province. The Company may file to recover uncollected debt retirement charges from Ontario Electricity Financial Company ("OEFC") once each year.

Rate setting:

Distribution revenue

For the distribution revenue included in electricity sales, the Company 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 expenses, debt and shareholder's equity required to support the Company's business. The Company 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.

2. Basis of presentation (continued):

(f) Rate regulation (continued):

As a licensed distributor, the Company 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 Company is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Company ultimately collects these amounts from customers.

The Company last filed a COS application in 2012 for rates effective May 1, 2013 to April 30, 2014. The GDP IPI-FDD for 2016 is 2.1%, the Company's productivity factor is 0.0% and the stretch factor is 0.45%, resulting in an available net adjustment of 1.65%. The Company submitted a request to forego this adjustment, resulting in the OEB approving a 0% change from 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 Company 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(g). The Company 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:

Electricity sales:

Electricity sales are recognized as the electricity is delivered to customers and includes the amounts billed to customers for electricity, including the cost of electricity supplied, distribution, and any other regulatory charges. Electricity revenue is recorded on the basis of regular meter readings and estimated customer usage since the last meter reading date to the end of the year. The related cost of power is recorded on the basis of power used.

3. Significant accounting policies (continued):

(b) Revenue recognition (continued):

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 Company has determined that it is acting as a principal for these electricity charges and, therefore, has presented electricity revenue on a gross basis.

The difference between the amounts charged by the Company to customers, based on regulated rates, and the corresponding cost of electricity and related electricity service costs billed monthly by the IESO is recorded as a settlement variance. In accordance with IFRS 14, this settlement variance is presented within regulatory balances on the balance sheets and within net movements in regulatory balances, net of tax on the statement of comprehensive income.

Revenue from contracts with customers:

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 initially 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 Company'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 economic useful life of the constructed or contributed asset, which represents the period of ongoing service to the customer.

Rendering of services:

Revenue earned from the provision of services is recognized as the service is rendered.

Government grants

Incentive payments to which the Company is entitled from the Independent Electricity System Operator (“IESO”) are recognized as revenue in the period when they are determined by the IESO and the amount is communicated to the Company.

(c) Inventory:

Inventories consist of parts, supplies and materials held for the future capital expansion and are 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 material 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.

3. Significant accounting policies (continued):

(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, less accumulated depreciation. All other items of PP&E are measured at cost, or, where the item is transferred from 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 the cost of materials, direct labour, 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 Company's borrowings. Qualifying assets are considered to be those that take a substantial period of time to construct.

When parts of an item of property, plant and equipment have different useful lives, they are accounted for as separate items (major components) of property, plant and equipment.

Gains and losses on the disposal of an item of PP&E are determined by comparing the proceeds from disposal, if any, with the carrying amount of the item of PP&E and are recognized net within other income 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 property, plant and equipment 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 Company and its cost can be measured reliably. In this event, the replaced part of property, plant and equipment is written off, and the related gain or loss is included in profit or loss. The costs of the day-to-day servicing of property, plant and equipment are recognized in profit or loss as incurred.

Depreciation is calculated over the depreciable amount and is recognized in profit or loss on a straight-line basis over the estimated useful life of each part or component of an item of property, plant and equipment. The depreciable amount is cost. Land is not depreciated. Construction-in-progress assets are not depreciated until the project is complete and in service.

The estimated useful lives are as follows:

Buildings	25 – 50 years
Transmission and distribution	15 – 60 years
Machinery and equipment	5 – 40 years

Depreciation methods, useful lives, and residual values are reviewed at each reporting date and adjusted prospectively if appropriate.

3. Significant accounting policies (continued):

(e) Impairment:

(i) Financial assets:

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 in respect of a financial asset measured at amortized cost is calculated as the difference between its current carrying amount (using prevailing interest rates), 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.

All impairment losses are recognized in profit or loss. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in profit or loss.

(ii) Non-financial assets:

The carrying amounts of the Company's non-financial assets, other than inventories 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"). The recoverable amount of an asset or cash-generating unit 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 cash-generating unit exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss.

Impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. 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, if no impairment loss had been recognized.

3. Significant accounting policies (continued):

(f) Provisions:

A provision is recognized if, as a result of a past event, the Company 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.

(g) Regulatory deferral accounts:

Regulatory deferral account debit balances represent costs incurred in excess of amounts billed to the customer at OEB approved rates. These amounts have been accumulated and deferred in anticipation of their future recovery in electricity distribution rates. Regulatory deferral account credit balances represent amounts billed to the customer at OEB approved rates in excess of costs incurred by the Company.

Regulatory deferral account debit balances are recognized if it is probable that future billings in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes. The offsetting amount is recognized in profit and loss. The debit balance is reduced by the amount of customer billings as electricity is delivered to the customer and the customer is billed at rates approved by the OEB for the recovery of the capitalized costs.

Regulatory deferral account credit balances are recognized if it is probable that future billings in an amount at least equal to the credit balance will be reduced as a result of rate-making activities. The offsetting amount is recognized in profit and loss. The credit balance is reduced by the amounts returned to customers as electricity is delivered to the customer at rates approved by the OEB for the return of the regulatory account credit balance.

The probability of recovery or repayment of the regulatory account balances are assess annually based upon the likelihood that the OEB will approve the change in rates to recover or repay the balance. Any resulting impairment loss is recognized in profit and loss in the year incurred.

Regulatory deferral accounts attract interest at OEB prescribed rates. In 2016 the rate was 1.1%.

(h) Credit support for service delivery:

Credit support for service delivery represents cash deposits from electricity distribution customers as well as construction deposits.

Deposits from electricity distribution customers are applied against any unpaid portion of individual customer accounts. Customer deposits in excess of unpaid account balances are refundable to individual customers upon termination of their electricity distribution service. Customer deposits are also refundable to residential electricity distribution customers demonstrating an acceptable level of credit risk, as determined by the Company.

3. Significant accounting policies (continued):

(h) Credit support for service delivery (continued):

Certain customers and developers are required to contribute towards the capital cost of construction in order to provide ongoing service. Cash contributions are initially recorded as credit support for service delivery, a current liability. Once the distribution system asset is completed or modified as outlined in the terms of the contract, the contribution amount is transferred to deferred revenue.

(i) Deferred revenue and assets transferred from customers:

Certain customers and developers are required to contribute towards the capital cost of construction in order to provide ongoing service. When an asset is received as a capital contribution, the asset is initially recognized at its fair value, with the corresponding amount recognized as deferred revenue. Deferred revenue represents the Company's obligation to continue to provide customers access to the supply of electricity, and is amortized to income on a straight-line basis over the economic useful life of the acquired or contributed asset, which represents the period of ongoing service to the customer.

(j) 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 and on regulatory assets.

Finance charges comprise interest expense on borrowings. Finance costs are recognized as an expense unless they are capitalized as part of the cost of qualifying assets.

(k) Payment in lieu of taxes:

The Company 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 Company makes payments in lieu of corporate taxes to the Ontario Electricity Financial Company ("OEFC"). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Company's Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations. Prior to October 1, 2001, the Company was not subject to income or capital taxes.

PILs comprises current and deferred payments in lieu of income tax. PILs recognized in income and loss except to the extent that it relates to items recognized directly in either comprehensive income or equity, in which case, it is recognized in comprehensive income or in equity.

Current PILS is the expected amount of tax payable on the taxable income 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 PILs comprise the net tax effects of temporary differences between the tax basis of assets and liabilities and their respective carrying amounts for accounting purposes, as well as for tax losses available to be carried forward to future years that are likely to be realized.

3. Significant accounting policies (continued):

(k) Payment in lieu of taxes (continued):

Deferred PILs assets and liabilities are measured using enacted or substantively enacted tax rates, at the reporting date, expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred PILs assets and liabilities of a change in tax rates is recognized in income in the year that includes the date of enactment or substantive enactment.

A deferred PILs asset is recognized to the extent that it is probable that future taxable income will be available against which the temporary difference can be utilized. Deferred PILs assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

(l) New standards and interpretations not yet effective:

The following new standards and interpretations are not yet effective but are considered to be relevant to the Company's financial statements:

i) IFRS 15 *Revenue from Contracts with Customers*

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 Company is assessing the impact of IFRS 15 on its results of operations, financial position and disclosures.

ii) IFRS 9 Financial Instruments ("IFRS 9"(2014))

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 multiphase 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 periods beginning on or after January 1, 2018 and must be applied retrospectively. The Company is assessing the impact of IFRS 9 on its results of operations, financial position, and disclosures.

iii) IFRS 16 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 Company is assessing the impact of IFRS 16 on its results of operations, financial position and disclosures.

3. Significant accounting policies (continued):

(l) New standards and interpretations not yet effective (continued):

iv) IAS 7 Disclosure Initiative:

In January 2016 the IASB issued Disclosure Initiative (Amendments to IAS 7). The amendments apply prospectively for annual periods beginning on or after January 1, 2017, earlier application is permitted.

The amendments require disclosures that enable users of financial statements to evaluate changes in liabilities arising from financing activities, including both changes arising from cash flow and non-cash changes. One way to meet this new disclosure requirement is to provide a reconciliation between the opening and closing balances for liabilities from financing activities.

The Company intends to adopt the amendments to IAS 7 in its financial statements for the annual period beginning on January 1, 2017. The Company does not expect the amendments to have a material impact on the financial statements.

4. Critical accounting estimates and judgments:

The Company makes estimates and assumptions about the future that affect the reported amounts of assets and liabilities. Estimates and judgments are continually evaluated based on historical experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. In the future, actual experience may differ from these estimates and assumptions.

The effect of a change in an accounting estimate is recognized prospectively by including it in comprehensive income in the period of the change, if the change affects that period only; or in the period of the change and future periods, if the change affects both.

The estimates and assumptions that have a significant risk of causing material adjustment to the carrying amounts of assets and liabilities within the next financial year are discussed below.

Fair value of financial instruments:

The Company determines the fair value of financial instruments that are not quoted in an active market, using valuation techniques. Those techniques are significantly affected by the assumptions used, including discount rates and estimates of future cash flows. In that regard, the derived fair value estimates cannot always be substantiated by comparison with independent markets and, in many cases, may not be capable of being realized immediately.

The methods, and assumptions applied, and the valuation techniques used, for financial instruments that are not quoted in an active market are disclosed in note 17.

Payment in lieu of taxes:

The Company periodically assesses its liabilities and contingencies related to PILs for all years open to audit based on the latest information available. For matters where it is probable that an adjustment will be made, the Company records its best estimate of the tax liability including the related interest and penalties in the current PILs provision. Management believes they have

4. Critical accounting estimates and judgments (continued):

adequately provided for the probable outcome of these matters; however, the final outcome may result in a materially different outcome that the amount included in the PILs liabilities.

5. Critical accounting estimates and judgments (continued):

Useful lives of depreciable assets:

Management reviews the useful lives of depreciable assets at each reporting date. At December 31, 2016, management assesses that the useful lives represent the expected utility of the assets to the Company. The carrying amounts are analyzed in note 7. Actual results, however, may vary due to technical obsolescence, particularly for software and electronic equipment.

Impairment:

An impairment loss is recognized for the amount by which an asset's carrying amount exceeds its recoverable amount, which is the higher of fair value less cost to sell and value-in-use. To determine the value-in-use, management estimates expected future cash flows from each asset or cash generating unit and determines a suitable interest rate in order to calculate the present value of those cash flows. In most cases, determining the applicable discount rate involves estimating the appropriate adjustment to market risk and the appropriate adjustment to asset-specific risk factors. In the process of measuring expected future cash flows management makes assumptions about future operating results. These assumptions relate to future events and circumstances.

5. Accounts receivable:

	2016	2015
Trade receivables	$ 6,372,195	$ 5,664,419
Other receivables	248,075	235,916
	$ 6,620,270	$ 5,900,335

6. Inventory:

The amount of inventories consumed by the Company and recognized as an expense during 2016 was $344,489 (2015 - $260,058).

	2016	2015
Stores	$ 765,430	$ 761,951
Wire and cable	489,754	502,375
Poles	232,569	228,871
	$ 1,487,753	$ 1,493,197

7. Property, plant and equipment:

(a) Cost or deemed cost:

	Land and buildings	Transmission & distribution	Plant & equipment	Construction -in- Progress	Total
Balance at January 1, 2016	$ 25,903,194	$52,662,822	$17,037,138	$ –	$ 95,603,154
Additions	89,694	5,243,415	655,517	–	5,988,626
Disposals/retirements	(737)	(103,741)	(1,553)	–	(106,031)
Balance at December 31, 2016	$ 25,992,151	$57,802,496	$17,691,102	$ –	$101,485,749

	Land and buildings	Transmission & distribution	Plant & equipment	Construction -in- Progress	Total
Balance at January 1, 2015	$ 25,830,986	$46,995,627	$16,367,884	$ –	$ 89,194,497
Additions	72,224	5,668,676	969,792	–	6,710,692
Disposals/retirements	(16)	(1,481)	(300,537)	–	(302,034)
Balance at December 31, 2015	$ 25,903,194	$52,662,822	$17,037,139	$ –	$ 95,603,155

(b) Accumulated depreciation:

	Land and buildings	Transmission & distribution	Plant & equipment	Construction -in- Progress	Total
Balance at January 1, 2016	$ 1,324,399	$ 4,967,777	$ 1,684,203	$ –	$ 7,976,379
Depreciation charge	665,842	2,749,462	786,870	–	4,202,174
Disposals/retirements	(737)	–	(105,293)	–	(106,030)
Balance at December 31, 2016	$ 1,989,504	$ 7,717,239	$ 2,365,780	$ –	$ 12,072,523

	Land and buildings	Transmission & distribution	Plant & equipment	Construction -in- Progress	Total
Balance at January 1, 2015	$ 661,571	$ 2,337,388	$ 897,420	$ –	$ 3,896,379
Depreciation charge	662,844	2,631,870	845,032	–	4,139,746
Disposals/retirements	(16)	(1,481)	(58,249)	–	(59,746)
Balance at December 31, 2015	$ 1,324,399	$ 4,967,777	$ 1,684,203	$ –	$ 7,976,379

7. Property, plant and equipment (continued):

(c) Carrying amounts:

	Land and buildings	Transmission & distribution	Plant & equipment	Construction -in-Progress	Total
At December 31, 2016	$ 24,002,647	50,085,257	15,325,322	–	$ 89,413,226
At December 31, 2015	24,578,795	47,695,045	15,352,935	–	87,626,775

(e) Security:

At December 31, 2016 properties with a carrying amount of $89,413,226 (2015 - $87,626,774) are subject to a general security agreement.

8. Payments in lieu of income taxes:

Payment in lieu of taxes expense (recovery):

	2016	2015
Current	$ (44,000)	$ 1,285,959
Deferred	3,000	296,000
Income tax expense (recovery)	$ (41,000)	$ 1,581,959

Reconciliation of effective tax rate:

	2016	2015
Earnings before payments in lieu of income taxes	$ 989,351	$ 7,111,640
Statutory rate	26.5%	26.5%
Profit excluding income tax	262,178	1,884,585
Increase (decrease) resulting from:		
Permanent difference	823	838
Change in regulatory accounts impacting current tax	(359,000)	(296,000)
Adjustment to prior year's recovery	28,000	–
Other	26,999	(7,464)
	$ (41,000)	$ 1,581,959

9. Regulatory deferral account balance:

The following is a reconciliation of the carrying amount for each class of regulatory deferral account balances:

	2015	Balances arising in the period	Recovery/ reversal	2016	Remaining recovery/ reversal period (years)
Regulatory deferral account debit balances					
Regulatory Asset recovery Account Phase 6	$ 21,987	$ 9,976	$ –	$ 31,963	<1
Regulatory Asset recovery Account Phase 8	–	(116,319)	743,680	627,361	1
Deferred taxes	390,000	–	–	390,000	
Stranded Meters	3,908	(61)	–	3,847	<1
Smart Meter Entity Charges	23,748	313,637	(302,117)	35,268	3
Total amount related to regulatory deferral account debit balances	$ 439,643	$ 207,233	$ 441,563	$1,088,439	

	2015	Balances arising in the period	Recovery/ reversal	2016	Remaining recovery/ reversal period (years)
Regulatory deferral account credit balances					
Settlement Variance	$ (5,021,855)	$ 1,975,071	$ –	$ (3,046,784)	<1
Deferred Taxes	(1,474,000)	–	3,000	(1,471,000)	
Regulatory Asset Recovery Account Phase 5	(30,544)	(90)	–	(30,634)	<1
Regulatory Asset Recovery Account Phase 7	(58,402)	(9)	(640)	(59,051)	<1
CGAAP Accounting Changes	(72,874)	–	72,876	2	1
LRAMVA	(10,355)	(124)	(23)	(10,502)	<1
Total amount related to regulatory deferral account credit balances	$ (6,668,030)	$ 1,974,848	$ 72,213	$ (4,617,969)	

The regulatory deferral account balances are recovered or settled through rates set 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 Company has received approval from the OEB to establish its regulatory deferral account balances.

Group 1 deferral and variance accounts (Group 1 accounts) track the differences between the costs that a distributor is billed for certain IESO and host distributor services (including the cost of power) and the associated revenues that the distributor receives from its customers for these services. The total net difference between these costs and revenues is disposed to customers through a temporary charge or credit known as a rate rider.

The OEB requires the Company to estimate its income taxes when it files a COS application to set its rates. As a result, the Company 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 Company's deferred tax balance fluctuates.

10. Long-term debt:

	2016	2015
Notes payable:		
(i) Ontario Infrastructure smart meter loan	$ 4,213,285	$ 4,485,507
(ii) Ontario Infrastructure building loan	19,633,212	20,146,013
(iii) Ontario Infrastructure construction loan	14,777,737	15,000,000
(iv) Note payable to parent company, PUC Inc.	26,534,040	26,534,040
	65,158,274	66,165,560
Current portion of long-term debt	1,211,084	15,785,022
	$ 63,947,190	$ 50,380,538

i) Smart Meter Loan with Ontario Infrastructure and Lands Corporation (OILC): Reducing Debenture Facility, amortization period of 15 years to July 15, 2028. The loan interest rate of 3.82%. Interest of $164,438 (2015 - $174,708) was paid and expensed during the year. The loan is payable in the amount of $220,496 semi-annual principal and interest. Security is in the form of a second ranking general security agreement.

ii) Land and Building Loan with OILC: Reducing Debenture Facility, amortization period of 25 years to October 1, 2038. The loan interest rate of 4.57%. Interest of $910,020 (2015 - $932,885) was paid and expensed during the year. The loan is payable in the amount of $118,568 monthly principal and interest. Security is in the form of a first charge over the Company's land and building and a third ranking general security agreement.

iii) Electric Distribution Infrastructure Loan with OILC: The construction loan was converted to long term debt in 2016, at an interest rate of 3.47%, repayable over 25 years by a blended principal and interest payment of $74,852 monthly. Interest of $394,071 (2015 - $212,884) was paid and expensed during the year. Security is in the form of a fourth ranking general security agreement and a guarantee and assignment of shares from the company’s shareholder, PUC Inc.

iv) Note payable to parent company, PUC Inc., bears interest payable quarterly at rates periodically negotiated and principal payable one year after demand. The average interest rate for 2016 was 6.1% (2015 – 6.1%). The balance outstanding for 2016 is $$26,534,040 (2015 - $26,534,040).

10. Long-term debt (continued):

Principal payments on the long-term debt are as follows:

2017	$ 1,211,084
2018	1,260,844
2019	1,312,680
2020	1,366,680
2021	1,422,937
2022 - 2035	58,584,049
	65,158,274
Less: current portion	(1,211,084)
Long-term portion of loan	$ 63,947,190

11. Customer deposits:

Customer deposits represent cash deposits from electricity distribution customers and retailers, as well as construction deposits.

Deposits from electricity distribution customers are refundable to customers who demonstrate an acceptable level of credit risk as determined by the Company in accordance with policies set out by the OEB or upon termination of their electricity distribution service. The balance at December 31, 2016 is $987,485 (2015 - $922,422).

12. Share capital:

	2016	2015
Authorized:		
Unlimited number of special shares, non-voting, non-cumulative Redeemable at $10,000 per share		
10,000 Common shares		
Issued and outstanding:		
8,612 common shares	$ 20,062,107	$ 20,062,107

13. Other operating revenue:

Other income comprises:

	2016	2015
Rendering of services	$ 3,238,358	$ 3,381,383
Other	142,964	149,030
Amortization of deferred revenue	112,433	110,389
Total other income	$ 3,493,755	$ 3,640,802

14. Finance income and expense:

	2016	2015
Interest income	$ 33,313	$ 26,460
Finance income	33,313	26,460
Interest expense on long-term debt	3,087,106	2,939,100
Other interest and carrying charges	(29,043)	64,813
	3,058,063	3,003,913
Net finance costs recognized in profit or loss	$ 3,024,750	$ 2,977,453

15. Commitments and contingencies:

General:

From time to time, the Company is involved in various litigation matters arising in the ordinary course of its business. The Company 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 Company's financial position, results of operations or its ability to carry on any of its business activities.

General Liability Insurance:

The Company 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.

16. Related party transactions:

(a) Parent, ultimate controlling party, and other related parties:

The sole shareholder of the Company is PUC Inc., which in turn is wholly-owned by the Corporation of the City of Sault Ste. Marie. The City produces financial statements that are available for public use. Other related parties include PUC Services Inc. (Services), and Public Utilities Commission of the City of Sault Ste. Marie (Utility).

(b) Key management personnel:

The key management personnel of the Company have been defined as members of its board of directors and is summarized below.

	2016	2015
Directors' fees	$ 7,827	$ 9,756

(c) Transactions with ultimate parent (the City):

In the year, the Company had the following significant transactions with its ultimate parent, a government entity:

The Company delivers electricity to the City throughout the year for the electricity needs of the City and its related organizations. Electricity delivery charges are at prices and under terms approved by the OEB. The amount charged to the City for electricity consumed by streetlights is $1,450,202 (2015 - $1,718,602) and for other electricity consumption is $4,275,882 (2015 - $3,668,401).

(d) Transactions with Services:

The Company has a management, operation and maintenance agreement with Services, which has been extended to November 30, 2017, under which Services manages, controls, administers and operates the business of the Company. During the year, management fees were paid to Services in the amount of $4,718,888 (2015 - $4,871,691).

The Company receives/(pays) interest on its receivable/payable balance to Services at the OEB prescribed short-term borrowing rate on its average monthly balance. Interest of $31,981 (2015 – $7,221) was received/(paid) during the year.

These transactions are in the normal course of operations and are measure at the exchange amount which is the amount of consideration agreed to by the related parties.

17. Financial instruments and risk management:

Fair value disclosure

Cash and cash equivalents are measured at fair value. The carrying values of receivables, and accounts payable and accrued charges 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.

Financial risks

The Company understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Company'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 Company, such as accounts receivable, expose it to credit risk. The Company earns its revenue from a broad base of customers located in the City. No single customer accounts for a balance in excess of 2.53% 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 net income. Subsequent recoveries of receivables previously provisioned are credited to net income. The balance of the allowance for impairment at December 31, 2016 is $100,000 (2015 - $100,000).

The Company's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2016, approximately $126,059 (2015 - $121,304) is considered 60 days past due. The Company has over 33 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 Company holds security deposits in the amount of $987,485 (2015 - $922,422).

(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 Company currently does not have any material commodity or foreign exchange risk. The Company is exposed to fluctuations in interest rates as the regulated rate of return for the Company'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.

17. Financial instruments and risk management (continued):

(c) Liquidity risk:

The Company monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Company's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest exposure. The Company monitors cash balances daily to ensure that a sufficient level of liquidity is on hand to meet financial commitments as they come due. As at December 31, 2016, no amounts had been drawn under the Company's credit facilities.

The majority of accounts payable, as reported on the balance sheet, are due within 30 days.

(d) Capital disclosures:

The main objectives of the Company, 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 Company's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2016, shareholder's equity amounts to $27,848,606 (2015 - $28,213,048) and long-term debt amounts to $65,158,275 (2015 - $66,165,560).

18. Comparative information:

Certain 2015 comparative information has been reclassified to conform to the financial statement presentation adopted for 2016. The changes made do not have an impact on the statement of comprehensive income.

APPENDIX 7

Mapped Audited FS to RRR Trial Balance 2013-2016

PUC Distribution

Filing : 2.1.13
RRR Section: A distributor shall provide in the form and manner required by the Board annually the uniform system of account balances mapped and reconciled to the annual audited financial statements.

2013 Trail Balance mapped to Audited Financial Statements

Color Legend: **Assets** **Liabilities and Equity** **Income Statement**

Account Description	Account Number	2013		
Cash	1005	314,787		1
Cash Advances and Working Funds	1010	0		
Interest Special Deposits	1020	0		
Dividend Special Deposits	1030	0		
Other Special Deposits	1040	0		
Term Deposits	1060	0		
Current Investments	1070	0		
Customer Accounts Receivable	1100	3,449,969		2
Accounts Receivable - Services	1102	0		
Accounts Receivable - Recoverable Work	1104	2,328,338		2
Accounts Receivable - Merchandise, Jobbing, etc.	1105	0		
Other Accounts Receivable	1110	2,107,787		2
Accrued Utility Revenues	1120	11,572,951		3
Accumulated Provision for Uncollectible Accounts--Credit	1130	0		
Interest and Dividends Receivable	1140	0		
Rents Receivable	1150	0		
Notes Receivable	1170	0		
Prepayments	1180	66,520		6
Miscellaneous Current and Accrued Assets	1190	0		
Accounts Receivable from Associated Companies	1200	0		
Notes Receivable from Associated Companies	1210	0		
Fuel Stock	1305	0		
Plant Materials and Operating Supplies	1330	1,675,485		5
Merchandise	1340	0		
Other Materials and Supplies	1350	0		
Long Term Investments in Non-Associated Companies	1405	0		
Long Term Receivable - Street Lighting Transfer	1408	0		
Other Special or Collateral Funds	1410	0		
Sinking Funds	1415	0		
Unamortized Debt Expense	1425	0		
Unamortized Discount on Long-Term Debt--Debit	1445	0		
Unamortized Deferred Foreign Currency Translation Gains and Losses	1455	0		
Other Non-Current Assets	1460	-1,940,000	7/10/17/18	
O.M.E.R.S. Past Service Costs	1465	0		
Past Service Costs - Employee Future Benefits	1470	0		
Past Service Costs - Other Pension Plans	1475	0		
Portfolio Investments - Associated Companies	1480	0		
Investment in Associated Companies - Significant Influence	1485	0		
Investment in Subsidiary Companies	1490	0		
Unrecovered Plant and Regulatory Study Costs	1505	0		
Other Regulatory Assets	1508	-52,200	7/10/17/18	
Preliminary Survey and Investigation Charges	1510	0		
Emission Allowance Inventory	1515	0		
Emission Allowances Withheld	1516	0		
RCVARetail	1518	-62,892	7/10/17/18	
Power Purchase Variance Account	1520	-6	7/10/17/18	
Special Purpose Charge Assessment Variance	1521	0		
Miscellaneous Deferred Debits	1525	0		
Deferred Losses from Disposition of Utility Plant	1530	0		
Renewable Connection Capital Deferral Account	1531	0		
Renewable Connection OM&A Deferral Account	1532	0		
Smart Grid Capital Deferral Account	1534	0		
Smart Grid Capital OM&A Account	1535	0		
Unamortized Loss on Reacquired Debt	1540	0		
Development Charge Deposits/ Receivables	1545	0		
RCVASTR	1548	35,437	7/10/17/18	
LV Variance Account	1550	0		
Smart Meter Entity Charge Variance Account	1551	23,891	7/10/17/18	
Smart Meter Capital and Recovery Offset Variance	1555	717,645	7/10/17/18	
Smart Meter OM&A Variance	1556	0		
Deferred Development Costs	1560	0		
Deferred Payments in Lieu of Taxes	1562	0		
Deferred PILs Contra Account	1563	0		
Conservation and Demand Management Expenditures and Recoveries	1565	0		
CDM Contra	1568	81,098	7/10/17/18	
LRAM Variance Account	1570	0		
Qualifying Transition Costs	1570	0		
Pre-market Opening Energy Variance	1571	0		
Extraordinary Event Costs	1572	0		
Deferred Rate Impact Amounts	1574	0		
CGAAP Accounting Changes	1576	-218,626	7/10/17/18	
RSVAWMS	1580	-2,206,085	7/10/17/18	
RSVAONE-TIME	1582	0		
RSVANW	1584	-287,546	7/10/17/18	
RSVACN	1586	0		
RSVAPOWER	1588	-120,404	7/10/17/18	
RSVAGA	1589	175,692	7/10/17/18	
Recovery of regulatory asset balances	1590	0		
2006 PILs & Taxes Variance	1592	0		
Disposition and Recovery of Regulatory Balances Control Account	1595	-1,667,473	7/10/17/18	
Electric Plant in Service - Control Account	1605	0		
Organization	1606	0		
Franchises and Consents	1608	0		
Miscellaneous Intangible Plant	1610	0		
Land	1615	0		
Land Rights	1616	0		
Buildings and Fixtures	1620	0		
Leasehold Improvements	1630	0		
Boiler Plant Equipment	1635	0		
Engines and Engine-Driven Generators	1640	0		
Turbogenerator Units	1645	0		
Reservoirs, Dams and Waterways	1650	0		
Water Wheels, Turbines and Generators	1655	0		
Roads, Railroads and Bridges	1660	0		
Fuel Holders, Producers and Accessories	1665	0		
Prime Movers	1670	0		
Generators	1675	0		
Accessory Electric Equipment	1680	0		
Miscellaneous Power Plant Equipment	1685	0		
Land	1705	0		
Land Rights	1706	602,307		8
Buildings and Fixtures	1708	0		
Leasehold Improvements	1710	0		

2013

Balance Sheet	Sum of or portions of:	
Cash	1	314,787
Accounts Receivable	2	7,886,094
Unbilled Revenue	3	11,572,951
Pmt in Lieu of Taxes Recoverable	4	343,139
Inventories	5	1,675,485
Prepaid Expenses & Deposits	6	66,520
Current Portion of Reg Assets	7/10/17/18	771,711
		22,630,686
PP&E	8	134,063,688
Less Accumulated Amortization	9	(52,595,690)
		81,467,997
Regulatory Assets	7/10/17/18	50,924
Future Taxes	11	1,940,000
		1,990,924
		106,089,607
Accts Payable & Accrued Liabilities	12	(10,702,292)
Customer Deposits	13	(712,536)
Deferred Revenue	14	(1,227,075)
Payable to PUC Services Inc.	15	(8,054,961)
Current Portion of LT Debt	16/19	(720,470)
Current Portion of Reg Liabilities	7/10/17/18	(3,053,420)
		(24,470,754)
Reg Liabilities	7/10/17/18	(3,238,482)
LT Debt	16/19	(51,917,609)
Share Capital	20	(20,062,107)
Retained Earnings	21	(6,400,654)
		(81,618,851)
		(106,089,606)

Income Statement	Sum of or portions of:	
Distribution Revenue	22	(16,735,058)
Energy Charges	23	(68,769,142)
Other Related Charges	24	(149,806)
Other	25	(4,832,457)
		(90,486,463)
Cost of Power	26	68,769,142
Gross Profit		(21,717,321)
Investment Income	27	(41,984)
Distribution & Transmission Exps	28	5,992,121
Amortization of PP&E	29	3,538,651
Administration Exps	30	4,438,267
Interest on LT Debt	31	2,184,394
Billing & Collecting	32	1,274,108
Community Relations	33	1,882,536
Other Interest	34	191,706
		19,501,781
Earnings before undernoted		(2,257,523)
Gain (Loss) on Sale of Property & Equipment	35	110,632
Earnings before Provision for Pmt in Lieu of Taxes		(2,146,891)
Current Income Taxes	36	35,925
Net Earnings & Comprehensive Income		**(2,110,966)**

Station Equipment	1715	0	
Towers and Fixtures	1720	0	
Poles and Fixtures	1725	1,759,071	8
Overhead Conductors and Devices	1730	84,490	8
Underground Conduit	1735	991,969	8
Underground Conductors and Devices	1740	238,716	8
Roads and Trails	1745	0	
Land	1805	89,159	8
Land Rights	1806	154,129	8
Buildings and Fixtures	1808	25,999,887	8
Leasehold Improvements	1810	0	
Transformer Station Equipment - Normally Primary above 50 kV	1815	9,056,274	8
Distribution Station Equipment - Normally Primary below 50 kV	1820	14,481,291	8
Storage Battery Equipment	1825	19,241	8
Poles, Towers and Fixtures	1830	15,168,787	8
Overhead Conductors and Devices	1835	13,952,280	8
Underground Conduit	1840	10,853,111	8
Underground Conductors and Devices	1845	20,163,323	8
Line Transformers	1850	17,435,095	8
Services	1855	4,905,827	8
Meters	1860	6,340,345	8
Other Installations on Customer's Premises	1865	0	
Leased Property on Customer Premises	1870	0	
Street Lighting and Signal Systems	1875	0	
Land	1905	0	
Land Rights	1906	0	
Buildings and Fixtures	1908	0	
Leasehold Improvements	1910	0	
Office Furniture and Equipment	1915	0	
Computer Equipment - Hardware	1920	20,338	8
Computer Software	1925	535,508	8
Transportation Equipment	1930	0	
Stores Equipment	1935	0	
Tools, Shop and Garage Equipment	1940	0	
Measurement and Testing Equipment	1945	0	
Power Operated Equipment	1950	0	
Communication Equipment	1955	0	
Miscellaneous Equipment	1960	0	
Water Heater Rental Units	1965	0	
Load Management Controls - Customer Premises	1970	0	
Load Management Controls - Utility Premises	1975	0	
System Supervisory Equipment	1980	4,354,819	8
Sentinel Lighting Rental Units	1985	0	
Other Tangible Property	1990	0	
Contributions and Grants - Credit	1995	-11,161,739	8/9
Property Under Capital Leases	2005	0	
Electric Plant Purchased or Sold	2010	0	
Experimental Electric Plant Unclassified	2020	0	
Electric Plant and Equipment Leased to Others	2030	0	
Electric Plant Held for Future Use	2040	0	
Completed Construction Not Classified--Electric	2050	0	
Construction Work in Progress--Electric	2055	6,788	8
Electric Plant Acquisition Adjustment	2060	0	
Other Electric Plant Adjustment	2065	0	
Other Utility Plant	2070	0	
Non-Utility Property Owned or Under Capital Leases	2075	0	
Accumulated Amortization of Electric Utility Plan - PP&E	2105	-54,583,019	9
Accumulated Amortization of Electric Utility Plant - Intangibles	2120	0	
Accumulated Amortization of Electric Plant Acquisition Adjustment	2140	0	
Accumulated Amortization of Other Utility Plant	2160	0	
Accumulated Amortization of Non-Utility Property	2180	0	
Accounts Payable	2205	-10,447,544	12
Customer Credit Balances	2208	-814,361	12/14
Current Portion of Customer Deposits	2210	-712,536	13
Dividends Declared	2215	0	
Miscellaneous Current and Accrued Liabilities	2220	-558,829	12/14
Notes and Loans Payable	2225	0	
Accounts Payable to Associated Companies	2240	-8,054,961	15
Notes Payable to Associated Companies	2242	0	
Debt Retirement Charges(DRC) Payable	2250	-118,163	12
Transmission Charges Payable	2252	0	
Electrical Safety Authority Fees Payable	2254	0	
Independent Market Operator Fees and Penalties Payable	2256	0	
Current Portion of Long Term Debt	2260	0	
Ontario Hydro Debt - Current Portion	2262	0	
Pensions and Employee Benefits - Current Portion	2264	0	
Accrued Interest on Long Term Debt	2268	0	
Matured Long Term Debt	2270	0	
Matured Interest on Long Term Debt	2272	0	
Obligations Under Capital Leases--Current	2285	0	
Commodity Taxes	2290	161,663	12
Payroll Deductions / Expenses Payable	2292	0	
Accrual for Taxes Payments in Lieu of Taxes, Etc.	2294	343,139	4
Future Income Taxes - Current	2296	0	
Accumulated Provision for Injuries and Damages	2305	0	
Employee Future Benefits	2306	0	
Other Pensions - Past Service Liability	2308	0	
Vested Sick Leave Liability	2310	0	
Accumulated Provision for Rate Refunds	2315	-152,133	12
Other Miscellaneous Non-Current Liabilities	2320	0	
Obligations Under Capital Lease--Non-Current	2325	0	
Development Charge Fund	2330	0	
Long Term Customer Deposits	2335	0	
Collateral Funds Liability	2340	0	
Unamortized Premium on Long Term Debt	2345	0	
O.M.E.R.S. - Past Service Liability - Long Term Portion	2348	0	
Future Income Tax - Non-Current	2350	1,940,000	11
Other Regulatory Liabilities	2405	0	
Deferred Gains from Disposition of Utility Plant	2410	0	
Unamortized Gain on Reacquired Debt	2415	0	
Other Deferred Credits	2425	52,200	7/10/17/18
Accrued Rate-Payer Benefit	2435	0	
Debentures Outstanding - Long Term Portion	2505	0	
Debenture Advances	2510	0	
Reacquired Bonds	2515	0	
Other Long Term Debt	2520	-26,104,039	16/19
Term Bank Loans - Long Term Portion	2525	0	
Ontario Hydro Debt Outstanding - Long Term Portion	2530	0	
Advances from Associated Companies	2550	-26,534,040	16/19
Common Shares Issued	3005	-20,062,107	20
Preference Shares Issued	3008	0	
Contributed Surplus	3010	0	
Donations Received	3020	0	
Development Charges Transferred to Equity	3022	0	
Capital Stock Held in Treasury	3026	0	
Miscellaneous Paid-In Capital	3030	0	
Installments Received on Capital Stock	3035	0	
Appropriated Retained Earnings	3040	0	
Unappropriated Retained Earnings	3045	-4,289,689	21
Balance Transferred From Income	3046	0	
Appropriations of Retained Earnings - Current Period	3047	0	

Dividends Payable-Preference Shares	3048	0	
Dividends Payable-Common Shares	3049	0	
Adjustment to Retained Earnings	3055	0	
Unappropriated Undistributed Subsidiary Earnings	3065	0	
Non-Utility Shareholders¿ Equity	3075	0	
Residential Energy Sales	4006	-28,076,344	23
Commercial Energy Sales	4010	0	
Industrial Energy Sales	4015	0	
Energy Sales to Large Users	4020	0	
Street Lighting Energy Sales	4025	-575,899	23
Sentinel Lighting Energy Sales	4030	-22,420	23
General Energy Sales	4035	-30,479,498	23
Other Energy Sales to Public Authorities	4040	0	
Energy Sales to Railroads and Railways	4045	0	
Revenue Adjustment	4050	0	
Energy Sales for Resale	4055	-1,968,788	23
Interdepartmental Energy Sales	4060	0	
Billed WMS	4062	-3,338,421	23
Billed One-Time	4064	0	
Billed NW	4066	-4,100,462	23
Billed CN	4068	0	
Billed - LV	4075	0	
Billed - Smart Meter Entity Charge	4076	-207,310	23
Distribution Services Revenue	4080	-16,854,755	22/24
Retail Services Revenues	4082	-29,639	24
Service Transaction Requests (STR) Revenues	4084	-470	24
Electric Services Incidental to Energy Sales	4090	0	
Transmission Charges Revenue	4105	0	
Transmission Services Revenue	4110	0	
Interdepartmental Rents	4205	0	
Rent from Electric Property	4210	-2,662,462	25
Other Utility Operating Income	4215	0	
Other Electric Revenues	4220	0	
Late Payment Charges	4225	-245,293	25
Sales of Water and Water Power	4230	0	
Miscellaneous Service Revenues	4235	-247,215	25
Provision for Rate Refunds	4240	0	
Government Assistance Directly Credited to Income	4245	0	
Regulatory Debits	4305	-43,830	25
Regulatory Credits	4310	0	
Revenues from Electric Plant Leased to Others	4315	0	
Expenses of Electric Plant Leased to Others	4320	0	
Special Purpose Charge Recovery	4324	0	
Revenues from Merchandise, Jobbing, Etc.	4325	-213,339	25
Costs and Expenses of Merchandising, Jobbing, Etc.	4330	7,548	25
Profits and Losses from Financial Instrument Hedges	4335	0	
Profits and Losses from Financial Instrument Investments	4340	0	
Gains from Disposition of Future Use Utility Plant	4345	0	
Losses from Disposition of Future Use Utility Plant	4350	0	
Gain on Disposition of Utility and Other Property	4355	0	
Loss on Disposition of Utility and Other Property	4360	110,632	35
Gains from Disposition of Allowances for Emission	4365	0	
Losses from Disposition of Allowances for Emission	4370	0	
Revenues from Non-Utility Operations	4375	-1,381,145	25
Expenses of Non-Utility Operations	4380	1,381,145	33
Non-Utility Rental Income	4385	0	
Miscellaneous Non-Operating Income	4390	-46,721	25
Rate-Payer Benefit Including Interest	4395	0	
Foreign Exchange Gains and Losses, Including Amortization	4398	0	
Interest and Dividend Income	4405	-41,984	27
Equity in Earnings of Subsidiary Companies	4415	0	
Operation Supervision and Engineering	4505	0	
Fuel	4510	0	
Steam Expense	4515	0	
Steam From Other Sources	4520	0	
Steam Transferred--Credit	4525	0	
Electric Expense	4530	0	
Water For Power	4535	0	
Water Power Taxes	4540	0	
Hydraulic Expenses	4545	0	
Generation Expense	4550	0	
Miscellaneous Power Generation Expenses	4555	0	
Rents	4560	0	
Allowances for Emissions	4565	0	
Maintenance Supervision and Engineering	4605	0	
Maintenance of Structures	4610	0	
Maintenance of Boiler Plant	4615	0	
Maintenance of Electric Plant	4620	0	
Maintenance of Reservoirs, Dams and Waterways	4625	0	
Maintenance of Water Wheels, Turbines and Generators	4630	0	
Maintenance of Generating and Electric Plant	4635	0	
Maintenance of Miscellaneous Power Generation Plant	4640	0	
Power Purchased	4705	45,668,915	26
Charges - Global Adjustment	4707	15,454,034	26
Charges-WMS	4708	3,338,421	26
Cost of Power Adjustments	4710	0	
Charges-One-Time	4712	0	
Charges-NW	4714	4,100,462	26
System Control and Load Dispatching	4715	0	
Charges-CN	4716	0	
Other Expenses	4720	0	
Competition Transition Expense	4725	0	
Rural Rate Assistance Expense	4730	0	
Charges - LV	4750	0	
Charges - Smart Metering Entity Charge	4751	207,310	26
Operation Supervision and Engineering	4805	0	
Load Dispatching	4810	0	
Station Buildings and Fixtures Expenses	4815	43,485	28
Transformer Station Equipment - Operating Labour	4820	0	
Transformer Station Equipment - Operating Supplies and Expense	4825	0	
Overhead Line Expenses	4830	348	28
Underground Line Expenses	4835	0	
Transmission of Electricity by Others	4840	0	
Miscellaneous Transmission Expense	4845	0	
Rents	4850	0	
Maintenance Supervision and Engineering	4905	0	
Maintenance of Transformer Station Buildings and Fixtures	4910	0	
Maintenance of Transformer Station Equipment	4916	0	
Maintenance of Towers, Poles and Fixtures	4930	0	
Maintenance of Overhead Conductors and Devices	4935	0	
Maintenance of Overhead Lines - Right of Way	4940	0	
Maintenance of Overhead Lines - Roads and Trails Repairs	4945	0	
Maintenance of Overhead Lines - Snow Removal from Roads and Trails	4950	0	
Maintenance of Underground Lines	4960	0	
Maintenance of Miscellaneous Transmission Plant	4965	0	
Operation Supervision and Engineering	5005	677,616	28
Load Dispatching	5010	269,912	28
Station Buildings and Fixtures Expense	5012	373,681	28
Transformer Station Equipment - Operation Labour	5014	245,802	28
Transformer Station Equipment - Operation Supplies and Expenses	5015	144,595	28
Distribution Station Equipment - Operation Labour	5016	133,116	28

Distribution Station Equipment - Operation Supplies and Expenses	5017	7,962	28
Overhead Distribution Lines and Feeders - Operation Labour	5020	596,851	28
Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	5025	196,630	28
Overhead Subtransmission Feeders - Operation	5030	0	
Overhead Distribution Transformers- Operation	5035	8,159	28
Underground Distribution Lines and Feeders - Operation Labour	5040	91,996	28
Underground Distribution Lines and Feeders - Operation Supplies and Expenses	5045	11,884	28
Underground Subtransmission Feeders - Operation	5050	0	
Underground Distribution Transformers - Operation	5055	43	28
Street Lighting and Signal System Expense	5060	0	
Meter Expense	5065	234,001	28
Customer Premises - Operation Labour	5070	134,792	28
Customer Premises - Materials and Expenses	5075	857	28
Miscellaneous Distribution Expense	5085	403,559	28
Underground Distribution Lines and Feeders - Rental Paid	5090	54	28
Overhead Distribution Lines and Feeders - Rental Paid	5095	1,295	28
Other Rent	5096	91,198	28
Maintenance Supervision and Engineering	5105	0	
Maintenance of Buildings and Fixtures - Distribution Stations	5110	81,360	28
Maintenance of Transformer Station Equipment	5112	74,799	28
Maintenance of Distribution Station Equipment	5114	34,140	28
Maintenance of Poles, Towers and Fixtures	5120	106,405	28
Maintenance of Overhead Conductors and Devices	5125	760,923	28
Maintenance of Overhead Services	5130	71,936	28
Overhead Distribution Lines and Feeders - Right of Way	5135	749,283	28
Maintenance of Underground Conduit	5145	80,557	28
Maintenance of Underground Conductors and Devices	5150	142,239	28
Maintenance of Underground Services	5155	121,744	28
Maintenance of Line Transformers	5160	22,017	28
Maintenance of Street Lighting and Signal Systems	5165	0	
Sentinel Lights - Labour	5170	0	
Sentinel Lights - Materials and Expenses	5172	0	
Maintenance of Meters	5175	78,882	28
Customer Installations Expenses- Leased Property	5178	0	
Water Heater Rentals - Labour	5185	0	
Water Heater Rentals - Materials and Expenses	5186	0	
Water Heater Controls - Labour	5190	0	
Water Heater Controls - Materials and Expenses	5192	0	
Maintenance of Other Installations on Customer Premises	5195	0	
Purchase of Transmission and System Services	5205	0	
Transmission Charges	5210	0	
Transmission Charges Recovered	5215	0	
Supervision	5305	12,646	32
Meter Reading Expense	5310	335,471	32
Customer Billing	5315	463,358	32
Collecting	5320	280,607	32
Collecting- Cash Over and Short	5325	0	
Collection Charges	5330	0	
Bad Debt Expense	5335	182,025	32
Miscellaneous Customer Accounts Expenses	5340	0	
Supervision	5405	66,751	33
Community Relations - Sundry	5410	414,346	33
Energy Conservation	5415	0	
Community Safety Program	5420	20,295	33
Miscellaneous Customer Service and Informational Expenses	5425	0	
Supervision	5505	0	
Demonstrating and Selling Expense	5510	0	
Advertising Expense	5515	0	
Miscellaneous Sales Expense	5520	0	
Executive Salaries and Expenses	5605	280,906	30
Management Salaries and Expenses	5610	454,373	30
General Administrative Salaries and Expenses	5615	410,356	30
Office Supplies and Expenses	5620	475,550	30
Administrative Expense Transferred/Credit	5625	0	
Outside Services Employed	5630	134,157	30
Property Insurance	5635	147,363	30
Injuries and Damages	5640	0	
Employee Pensions and Benefits	5645	0	
Franchise Requirements	5650	0	
Regulatory Expenses	5655	297,503	30
General Advertising Expenses	5660	0	
Miscellaneous General Expenses	5665	166,657	30
Rent	5670	0	
Maintenance of General Plant	5675	2,005,468	30
Electrical Safety Authority Fees	5680	0	
Special Purpose Charge Expense	5681	0	
Independent Market Operator Fees and Penalties	5685	0	
OM&A Contra	5695	0	
Amortization Expense - Property, Plant, and Equipment	5705	3,928,071	29
Amortization of Limited Term Electric Plant	5710	0	
Amortization of Intangibles and Other Electric Plant	5715	0	
Amortization of Electric Plant Acquisition Adjustments	5720	0	
Miscellaneous Amortization	5725	-389,420	29
Amortization of Unrecovered Plant and Regulatory Study Costs	5730	0	
Amortization of Deferred Development Costs	5735	0	
Amortization of Deferred Charges	5740	0	
Interest on Long Term Debt	6005	565,418	31
Amortization of Debt Discount and Expense	6010	0	
Amortization of Premium on Debt/Credit	6015	0	
Amortization of Loss on Reacquired Debt	6020	0	
Amortization of Gain on Reacquired Debt--Credit	6025	0	
Interest on Debt to Associated Companies	6030	1,618,976	31
Other Interest Expense	6035	191,706	34
Allowance for Borrowed Funds Used During Construction--Credit	6040	0	
Allowance For Other Funds Used During Construction	6042	0	
Interest Expense on Capital Lease Obligations	6045	0	
Taxes Other Than Income Taxes	6105	46,062	30
Income Taxes	6110	35,925	36
Provision for Future Income Taxes	6115	0	
Donations	6205	19,873	30
Life Insurance	6210	0	
Penalties	6215	0	
Other Deductions	6225	0	
Extraordinary Income	6305	0	
Extraordinary Deductions	6310	0	
Income Taxes: Extraordinary Item	6315	0	
Discontinues Operations - Income/ Gains	6405	0	
Discontinued Operations - Deductions/ Losses	6410	0	
Income Taxes, Discontinued Operations	6415	0	
		0	

PUC Distribution

Filing : 2.1.13
RRR Section: A distributor shall provide in the form and manner required by the Board annually the uniform system of account balances mapped and reconciled to the annual audited financial statements.

2014 Trial Balance Mapped to Audited Financial Statements

Color Legend: **Assets** **Liabilities and Equity** **Income Statement**

Account Description	Account Number	2014	
Cash	1005	4,118,664	1
Cash Advances and Working Funds	1010	0	
Interest Special Deposits	1020	0	
Dividend Special Deposits	1030	0	
Other Special Deposits	1040	0	
Term Deposits	1060	0	
Current Investments	1070	0	
Customer Accounts Receivable	1100	6,544,425	2
Accounts Receivable - Services	1102	0	
Accounts Receivable - Recoverable Work	1104	822,194	2
Accounts Receivable - Merchandise, Jobbing, etc.	1105	0	
Other Accounts Receivable	1110	177,728	2
Accrued Utility Revenues	1120	10,004,921	3
Accumulated Provision for Uncollectible Accounts--Credit	1130	0	
Interest and Dividends Receivable	1140	0	
Rents Receivable	1150	0	
Notes Receivable	1170	0	
Prepayments	1180	62,200	6
Miscellaneous Current and Accrued Assets	1190	0	
Accounts Receivable from Associated Companies	1200	0	
Notes Receivable from Associated Companies	1210	0	
Fuel Stock	1305	0	
Plant Materials and Operating Supplies	1330	1,614,472	5
Merchandise	1340	0	
Other Materials and Supplies	1350	0	
Long Term Investments in Non-Associated Companies	1405	0	
Long Term Receivable - Street Lighting Transfer	1408	0	
Other Special or Collateral Funds	1410	0	
Sinking Funds	1415	0	
Unamortized Debt Expense	1425	0	
Unamortized Discount on Long-Term Debt--Debit	1445	0	
Unamortized Deferred Foreign Currency Translation Gains and Losses	1455	0	
Other Non-Current Assets	1460	-1,380,000	7/10/17/18
O.M.E.R.S. Past Service Costs	1465	0	
Past Service Costs - Employee Future Benefits	1470	0	
Past Service Costs - Other Pension Plans	1475	0	
Portfolio Investments - Associated Companies	1480	0	
Investment in Associated Companies - Significant Influence	1485	0	
Investment in Subsidiary Companies	1490	0	
Unrecovered Plant and Regulatory Study Costs	1505	0	
Other Regulatory Assets	1508	-156,600	7/10/17/18
Preliminary Survey and Investigation Charges	1510	0	
Emission Allowance Inventory	1515	0	
Emission Allowances Withheld	1516	0	
RCVARetail	1518	-90,861	7/10/17/18
Power Purchase Variance Account	1520	0	
Special Purpose Charge Assessment Variance	1521	0	
Miscellaneous Deferred Debits	1525	0	
Deferred Losses from Disposition of Utility Plant	1530	0	
Renewable Connection Capital Deferral Account	1531	0	
Renewable Connection OM&A Deferral Account	1532	0	
Smart Grid Capital Deferral Account	1534	0	
Smart Grid Capital OM&A Account	1535	0	
Unamortized Loss on Reacquired Debt	1540	0	
Development Charge Deposits/ Receivables	1545	0	
RCVASTR	1548	55,020	7/10/17/18
LV Variance Account	1550	0	
Smart Meter Entity Charge Variance Account	1551	23,889	7/10/17/18
Smart Meter Capital and Recovery Offset Variance	1555	4,015	7/10/17/18
Smart Meter OM&A Variance	1556	0	
Deferred Development Costs	1560	0	
Deferred Payments in Lieu of Taxes	1562	0	
Deferred PILs Contra Account	1563	0	
Conservation and Demand Management Expenditures and Recoveries	1565	0	
CDM Contra	1568	36,758	7/10/17/18
LRAM Variance Account	1570	0	
Qualifying Transition Costs	1570	0	
Pre-market Opening Energy Variance	1571	0	
Extraordinary Event Costs	1572	0	
Deferred Rate Impact Amounts	1574	0	
CGAAP Accounting Changes	1576	-145,750	7/10/17/18
RSVAWMS	1580	-1,109,420	7/10/17/18
RSVAONE-TIME	1582	0	
RSVANW	1584	311,500	7/10/17/18
RSVACN	1586	0	
RSVAPOWER	1588	912,021	7/10/17/18
RSVAGA	1589	1,337,677	7/10/17/18
Recovery of regulatory asset balances	1590	0	
2006 PILs & Taxes Variance	1592	0	
Disposition and Recovery of Regulatory Balances Control Account	1595	-1,080,502	7/10/17/18
Electric Plant in Service - Control Account	1605	0	
Organization	1606	0	
Franchises and Consents	1608	0	
Miscellaneous Intangible Plant	1610	0	
Land	1615	0	
Land Rights	1616	0	
Buildings and Fixtures	1620	0	
Leasehold Improvements	1630	0	
Boiler Plant Equipment	1635	0	
Engines and Engine-Driven Generators	1640	0	
Turbogenerator Units	1645	0	
Reservoirs, Dams and Waterways	1650	0	
Water Wheels, Turbines and Generators	1655	0	
Roads, Railroads and Bridges	1660	0	
Fuel Holders, Producers and Accessories	1665	0	
Prime Movers	1670	0	
Generators	1675	0	
Accessory Electric Equipment	1680	0	
Miscellaneous Power Plant Equipment	1685	0	
Land	1705	0	
Land Rights	1706	602,307	8
Buildings and Fixtures	1708	0	
Leasehold Improvements	1710	0	

2014

Balance Sheet	Sum of or portions of:	
Cash	1	4,118,664
Accounts Receivable	2	7,544,347
Unbilled Revenue	3	10,004,921
Pmt in Lieu of Taxes Recoverable	4	497,819
Inventories	5	1,614,472
Prepaid Expenses & Deposits	6	62,200
Current Portion of Reg Assets	7/10/17/18	28,520
		23,870,942
PP&E	8	140,656,187
Less Accumulated Amortization	9	(56,092,472)
		84,563,714
Regulatory Assets	7/10/17/18	1,482,115
Future Taxes	11	1,403,460
		2,885,575
		111,320,232
Accts Payable & Accrued Liabilities	12	(10,791,841)
Customer Deposits	13	(854,761)
Deferred Revenue	14	(563,782)
Payable to PUC Services Inc.	15	(1,945,721)
Current Portion of LT Debt	16/19	(15,752,049)
Current Portion of Reg Liabilities	7/10/17/18	(1,153,830)
		(31,061,984)
Reg Liabilities	7/10/17/18	(1,482,458)
LT Debt	16/19	(51,165,560)
Share Capital	20	(20,062,107)
Retained Earnings	21	(7,548,123)
		(80,258,248)
		(111,320,232)

Income Statement	Sum of or portions of:	
Distribution Revenue	22	(16,386,768)
Energy Charges	23	(70,473,134)
Other Related Charges	24	(148,326)
Other	25	(3,995,623)
		(91,003,851)
Cost of Power	26	70,473,134
Gross Profit		(20,530,717)
Investment Income	27	(7,555)
Distribution & Transmission Exps	28	5,773,407
Amortization of PP&E	29	3,657,061
Administration Exps	30	3,332,931
Interest on LT Debt	31	2,756,657
Billing & Collecting	32	1,373,301
Community Relations	33	2,516,075
Other Interest	34	259,935
		19,669,367
Earnings before undernoted		(868,905)
Gain (Loss) on Sale of Property & Equipment	35	-
Earnings before Provision for Pmt in Lieu of Taxes		(868,905)
Current Income Taxes	36	(278,563)
Net Earnings & Comprehensive Income		**(1,147,468)**

Station Equipment	1715	0	
Towers and Fixtures	1720	0	
Poles and Fixtures	1725	1,759,071	8
Overhead Conductors and Devices	1730	84,490	8
Underground Conduit	1735	991,969	8
Underground Conductors and Devices	1740	238,716	8
Roads and Trails	1745	0	
Land	1805	89,159	8
Land Rights	1806	160,927	8
Buildings and Fixtures	1808	26,224,990	8
Leasehold Improvements	1810	0	
Transformer Station Equipment - Normally Primary above 50 kV	1815	9,667,523	8
Distribution Station Equipment - Normally Primary below 50 kV	1820	15,726,448	8
Storage Battery Equipment	1825	19,241	8
Poles, Towers and Fixtures	1830	17,450,755	8
Overhead Conductors and Devices	1835	14,912,330	8
Underground Conduit	1840	11,135,248	8
Underground Conductors and Devices	1845	20,746,042	8
Line Transformers	1850	18,252,421	8
Services	1855	5,447,385	8
Meters	1860	6,481,434	8
Other Installations on Customer's Premises	1865	0	
Leased Property on Customer Premises	1870	0	
Street Lighting and Signal Systems	1875	0	
Land	1905	0	
Land Rights	1906	0	
Buildings and Fixtures	1908	0	
Leasehold Improvements	1910	0	
Office Furniture and Equipment	1915	0	
Computer Equipment - Hardware	1920	2,945	8
Computer Software	1925	346,172	8
Transportation Equipment	1930	0	
Stores Equipment	1935	0	
Tools, Shop and Garage Equipment	1940	0	
Measurement and Testing Equipment	1945	0	
Power Operated Equipment	1950	0	
Communication Equipment	1955	0	
Miscellaneous Equipment	1960	0	
Water Heater Rental Units	1965	0	
Load Management Controls - Customer Premises	1970	0	
Load Management Controls - Utility Premises	1975	0	
System Supervisory Equipment	1980	4,511,413	8
Sentinel Lighting Rental Units	1985	0	
Other Tangible Property	1990	0	
Contributions and Grants - Credit	1995	-11,864,123	8/9
Property Under Capital Leases	2005	0	
Electric Plant Purchased or Sold	2010	0	
Experimental Electric Plant Unclassified	2020	0	
Electric Plant and Equipment Leased to Others	2030	0	
Electric Plant Held for Future Use	2040	0	
Completed Construction Not Classified--Electric	2050	0	
Construction Work in Progress--Electric	2055	0	8
Electric Plant Acquisition Adjustment	2060	0	
Other Electric Plant Adjustment	2065	0	
Other Utility Plant	2070	0	
Non-Utility Property Owned or Under Capital Leases	2075	0	
Accumulated Amortization of Electric Utility Plan - PP&E	2105	-58,423,149	9
Accumulated Amortization of Electric Utility Plant - Intangibles	2120	0	
Accumulated Amortization of Electric Plant Acquisition Adjustment	2140	0	
Accumulated Amortization of Other Utility Plant	2160	0	
Accumulated Amortization of Non-Utility Property	2180	0	
Accounts Payable	2205	-11,381,368	12
Customer Credit Balances	2208	-623,795	12/14
Current Portion of Customer Deposits	2210	-854,761	13
Dividends Declared	2215	0	
Miscellaneous Current and Accrued Liabilities	2220	-74,018	12/14
Notes and Loans Payable	2225	0	
Accounts Payable to Associated Companies	2240	-1,945,721	15
Notes Payable to Associated Companies	2242	0	
Debt Retirement Charges(DRC) Payable	2250	-119,830	12
Transmission Charges Payable	2252	0	
Electrical Safety Authority Fees Payable	2254	0	
Independent Market Operator Fees and Penalties Payable	2256	0	
Current Portion of Long Term Debt	2260	0	
Ontario Hydro Debt - Current Portion	2262	0	
Pensions and Employee Benefits - Current Portion	2264	0	
Accrued Interest on Long Term Debt	2268	-6,822	12
Matured Long Term Debt	2270	0	
Matured Interest on Long Term Debt	2272	0	
Obligations Under Capital Leases--Current	2285	0	
Commodity Taxes	2290	1,002,342	12
Payroll Deductions / Expenses Payable	2292	0	
Accrual for Taxes Payments in Lieu of Taxes, Etc.	2294	497,819	4
Future Income Taxes - Current	2296	0	
Accumulated Provision for Injuries and Damages	2305	0	
Employee Future Benefits	2306	0	
Other Pensions - Past Service Liability	2308	0	
Vested Sick Leave Liability	2310	0	
Accumulated Provision for Rate Refunds	2315	-152,133	12
Other Miscellaneous Non-Current Liabilities	2320	0	
Obligations Under Capital Lease--Non-Current	2325	0	
Development Charge Fund	2330	0	
Long Term Customer Deposits	2335	0	
Collateral Funds Liability	2340	0	
Unamortized Premium on Long Term Debt	2345	0	
O.M.E.R.S. - Past Service Liability - Long Term Portion	2348	0	
Future Income Tax - Non-Current	2350	1,403,460	11
Other Regulatory Liabilities	2405	0	
Deferred Gains from Disposition of Utility Plant	2410	0	
Unamortized Gain on Reacquired Debt	2415	0	
Other Deferred Credits	2425	156,600	7/10/17/18
Accrued Rate-Payer Benefit	2435	0	
Debentures Outstanding - Long Term Portion	2505	0	
Debenture Advances	2510	0	
Reacquired Bonds	2515	0	
Other Long Term Debt	2520	-40,383,569	16/19
Term Bank Loans - Long Term Portion	2525	0	
Ontario Hydro Debt Outstanding - Long Term Portion	2530	0	
Advances from Associated Companies	2550	-26,534,040	16/19
Common Shares Issued	3005	-20,062,107	20
Preference Shares Issued	3008	0	
Contributed Surplus	3010	0	
Donations Received	3020	0	
Development Charges Transferred to Equity	3022	0	
Capital Stock Held in Treasury	3026	0	
Miscellaneous Paid-In Capital	3030	0	
Installments Received on Capital Stock	3035	0	
Appropriated Retained Earnings	3040	0	
Unappropriated Retained Earnings	3045	-6,400,655	21
Balance Transferred From Income	3046	0	
Appropriations of Retained Earnings - Current Period	3047	0	

Dividends Payable-Preference Shares	3048	0	
Dividends Payable-Common Shares	3049	0	
Adjustment to Retained Earnings	3055	0	
Unappropriated Undistributed Subsidiary Earnings	3065	0	
Non-Utility Shareholders¿ Equity	3075	0	
Residential Energy Sales	4006	-27,897,738	23
Commercial Energy Sales	4010	0	
Industrial Energy Sales	4015	0	
Energy Sales to Large Users	4020	0	
Street Lighting Energy Sales	4025	-742,686	23
Sentinel Lighting Energy Sales	4030	-25,400	23
General Energy Sales	4035	-31,474,604	23
Other Energy Sales to Public Authorities	4040	0	
Energy Sales to Railroads and Railways	4045	0	
Revenue Adjustment	4050	0	
Energy Sales for Resale	4055	-2,525,618	23
Interdepartmental Energy Sales	4060	0	
Billed WMS	4062	-3,307,697	23
Billed One-Time	4064	0	
Billed NW	4066	-4,155,953	23
Billed CN	4068	0	
Billed - LV	4075	0	
Billed - Smart Meter Entity Charge	4076	-343,438	23
Distribution Services Revenue	4080	-16,506,382	22/24
Retail Services Revenues	4082	-28,305	24
Service Transaction Requests (STR) Revenues	4084	-408	24
Electric Services Incidental to Energy Sales	4090	0	
Transmission Charges Revenue	4105	0	
Transmission Services Revenue	4110	0	
Interdepartmental Rents	4205	0	
Rent from Electric Property	4210	-1,609,979	25
Other Utility Operating Income	4215	0	
Other Electric Revenues	4220	0	
Late Payment Charges	4225	-270,758	25
Sales of Water and Water Power	4230	0	
Miscellaneous Service Revenues	4235	-238,812	25
Provision for Rate Refunds	4240	0	
Government Assistance Directly Credited to Income	4245	0	
Regulatory Debits	4305	0	
Regulatory Credits	4310	0	
Revenues from Electric Plant Leased to Others	4315	0	
Expenses of Electric Plant Leased to Others	4320	0	
Special Purpose Charge Recovery	4324	0	
Revenues from Merchandise, Jobbing, Etc.	4325	-83,547	25
Costs and Expenses of Merchandising, Jobbing, Etc.	4330	8,212	25
Profits and Losses from Financial Instrument Hedges	4335	0	
Profits and Losses from Financial Instrument Investments	4340	0	
Gains from Disposition of Future Use Utility Plant	4345	0	
Losses from Disposition of Future Use Utility Plant	4350	0	
Gain on Disposition of Utility and Other Property	4355	0	
Loss on Disposition of Utility and Other Property	4360	0	
Gains from Disposition of Allowances for Emission	4365	0	
Losses from Disposition of Allowances for Emission	4370	0	
Revenues from Non-Utility Operations	4375	-1,779,725	25
Expenses of Non-Utility Operations	4380	1,958,374	33
Non-Utility Rental Income	4385	0	
Miscellaneous Non-Operating Income	4390	-21,014	25
Rate-Payer Benefit Including Interest	4395	0	
Foreign Exchange Gains and Losses, Including Amortization	4398	0	
Interest and Dividend Income	4405	-7,555	27
Equity in Earnings of Subsidiary Companies	4415	0	
Operation Supervision and Engineering	4505	0	
Fuel	4510	0	
Steam Expense	4515	0	
Steam From Other Sources	4520	0	
Steam Transferred--Credit	4525	0	
Electric Expense	4530	0	
Water For Power	4535	0	
Water Power Taxes	4540	0	
Hydraulic Expenses	4545	0	
Generation Expense	4550	0	
Miscellaneous Power Generation Expenses	4555	0	
Rents	4560	0	
Allowances for Emissions	4565	0	
Maintenance Supervision and Engineering	4605	0	
Maintenance of Structures	4610	0	
Maintenance of Boiler Plant	4615	0	
Maintenance of Electric Plant	4620	0	
Maintenance of Reservoirs, Dams and Waterways	4625	0	
Maintenance of Water Wheels, Turbines and Generators	4630	0	
Maintenance of Generating and Electric Plant	4635	0	
Maintenance of Miscellaneous Power Generation Plant	4640	0	
Power Purchased	4705	49,371,071	26
Charges - Global Adjustment	4707	13,294,976	26
Charges-WMS	4708	3,307,697	26
Cost of Power Adjustments	4710	0	
Charges-One-Time	4712	0	
Charges-NW	4714	4,155,953	26
System Control and Load Dispatching	4715	0	
Charges-CN	4716	0	
Other Expenses	4720	0	
Competition Transition Expense	4725	0	
Rural Rate Assistance Expense	4730	0	
Charges - LV	4750	0	
Charges - Smart Metering Entity Charge	4751	343,438	26
Operation Supervision and Engineering	4805	0	
Load Dispatching	4810	0	
Station Buildings and Fixtures Expenses	4815	34,813	28
Transformer Station Equipment - Operating Labour	4820	0	
Transformer Station Equipment - Operating Supplies and Expense	4825	0	
Overhead Line Expenses	4830	0	
Underground Line Expenses	4835	0	
Transmission of Electricity by Others	4840	0	
Miscellaneous Transmission Expense	4845	0	
Rents	4850	0	
Maintenance Supervision and Engineering	4905	0	
Maintenance of Transformer Station Buildings and Fixtures	4910	0	
Maintenance of Transformer Station Equipment	4916	0	
Maintenance of Towers, Poles and Fixtures	4930	0	
Maintenance of Overhead Conductors and Devices	4935	0	
Maintenance of Overhead Lines - Right of Way	4940	3,808	28
Maintenance of Overhead Lines - Roads and Trails Repairs	4945	0	
Maintenance of Overhead Lines - Snow Removal from Roads and Trails	4950	0	
Maintenance of Underground Lines	4960	0	
Maintenance of Miscellaneous Transmission Plant	4965	0	
Operation Supervision and Engineering	5005	607,190	28
Load Dispatching	5010	252,338	28
Station Buildings and Fixtures Expense	5012	533,072	28
Transformer Station Equipment - Operation Labour	5014	129,731	28
Transformer Station Equipment - Operation Supplies and Expenses	5015	21,819	28
Distribution Station Equipment - Operation Labour	5016	32,773	28

Distribution Station Equipment - Operation Supplies and Expenses	5017	24,461	28
Overhead Distribution Lines and Feeders - Operation Labour	5020	586,671	28
Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	5025	312,267	28
Overhead Subtransmission Feeders - Operation	5030	0	
Overhead Distribution Transformers- Operation	5035	285	28
Underground Distribution Lines and Feeders - Operation Labour	5040	174,477	28
Underground Distribution Lines and Feeders - Operation Supplies and Expenses	5045	29,907	28
Underground Subtransmission Feeders - Operation	5050	0	
Underground Distribution Transformers - Operation	5055	728	28
Street Lighting and Signal System Expense	5060	0	
Meter Expense	5065	249,353	28
Customer Premises - Operation Labour	5070	49,828	28
Customer Premises - Materials and Expenses	5075	20,525	28
Miscellaneous Distribution Expense	5085	397,481	28
Underground Distribution Lines and Feeders - Rental Paid	5090	53	28
Overhead Distribution Lines and Feeders - Rental Paid	5095	8,477	28
Other Rent	5096	92,529	28
Maintenance Supervision and Engineering	5105	0	
Maintenance of Buildings and Fixtures - Distribution Stations	5110	186,275	28
Maintenance of Transformer Station Equipment	5112	22,190	28
Maintenance of Distribution Station Equipment	5114	35,117	28
Maintenance of Poles, Towers and Fixtures	5120	51,969	28
Maintenance of Overhead Conductors and Devices	5125	562,509	28
Maintenance of Overhead Services	5130	124,265	28
Overhead Distribution Lines and Feeders - Right of Way	5135	838,109	28
Maintenance of Underground Conduit	5145	102,696	28
Maintenance of Underground Conductors and Devices	5150	93,513	28
Maintenance of Underground Services	5155	110,347	28
Maintenance of Line Transformers	5160	27,815	28
Maintenance of Street Lighting and Signal Systems	5165	0	
Sentinel Lights - Labour	5170	0	
Sentinel Lights - Materials and Expenses	5172	0	
Maintenance of Meters	5175	56,018	28
Customer Installations Expenses- Leased Property	5178	0	
Water Heater Rentals - Labour	5185	0	
Water Heater Rentals - Materials and Expenses	5186	0	
Water Heater Controls - Labour	5190	0	
Water Heater Controls - Materials and Expenses	5192	0	
Maintenance of Other Installations on Customer Premises	5195	0	
Purchase of Transmission and System Services	5205	0	
Transmission Charges	5210	0	
Transmission Charges Recovered	5215	0	
Supervision	5305	74,474	32
Meter Reading Expense	5310	339,208	32
Customer Billing	5315	552,743	32
Collecting	5320	282,201	32
Collecting- Cash Over and Short	5325	-2,918	32
Collection Charges	5330	0	
Bad Debt Expense	5335	127,593	32
Miscellaneous Customer Accounts Expenses	5340	0	
Supervision	5405	66,055	33
Community Relations - Sundry	5410	465,281	33
Energy Conservation	5415	0	
Community Safety Program	5420	26,365	33
Miscellaneous Customer Service and Informational Expenses	5425	0	
Supervision	5505	0	
Demonstrating and Selling Expense	5510	0	
Advertising Expense	5515	0	
Miscellaneous Sales Expense	5520	0	
Executive Salaries and Expenses	5605	335,490	30
Management Salaries and Expenses	5610	523,260	30
General Administrative Salaries and Expenses	5615	375,128	30
Office Supplies and Expenses	5620	425,275	30
Administrative Expense Transferred/Credit	5625	0	
Outside Services Employed	5630	230,840	30
Property Insurance	5635	198,627	30
Injuries and Damages	5640	0	
Employee Pensions and Benefits	5645	0	
Franchise Requirements	5650	0	
Regulatory Expenses	5655	121,885	30
General Advertising Expenses	5660	0	
Miscellaneous General Expenses	5665	235,742	30
Rent	5670	0	
Maintenance of General Plant	5675	823,330	30
Electrical Safety Authority Fees	5680	0	
Special Purpose Charge Expense	5681	0	
Independent Market Operator Fees and Penalties	5685	0	
OM&A Contra	5695	0	
Amortization Expense - Property, Plant, and Equipment	5705	4,073,284	29
Amortization of Limited Term Electric Plant	5710	0	
Amortization of Intangibles and Other Electric Plant	5715	0	
Amortization of Electric Plant Acquisition Adjustments	5720	0	
Miscellaneous Amortization	5725	-416,224	29
Amortization of Unrecovered Plant and Regulatory Study Costs	5730	0	
Amortization of Deferred Development Costs	5735	0	
Amortization of Deferred Charges	5740	0	
Interest on Long Term Debt	6005	1,138,081	31
Amortization of Debt Discount and Expense	6010	0	
Amortization of Premium on Debt/Credit	6015	0	
Amortization of Loss on Reacquired Debt	6020	0	
Amortization of Gain on Reacquired Debt--Credit	6025	0	
Interest on Debt to Associated Companies	6030	1,618,576	31
Other Interest Expense	6035	259,935	34
Allowance for Borrowed Funds Used During Construction--Credit	6040	0	
Allowance For Other Funds Used During Construction	6042	0	
Interest Expense on Capital Lease Obligations	6045	0	
Taxes Other Than Income Taxes	6105	40,740	30
Income Taxes	6110	-278,563	36
Provision for Future Income Taxes	6115	0	
Donations	6205	22,610	30
Life Insurance	6210	0	
Penalties	6215	3	30
Other Deductions	6225	0	
Extraordinary Income	6305	0	
Extraordinary Deductions	6310	0	
Income Taxes: Extraordinary Item	6315	0	
Discontinues Operations - Income/ Gains	6405	0	
Discontinued Operations - Deductions/ Losses	6410	0	
Income Taxes, Discontinued Operations	6415	0	
		0	

Color Legend: **Assets** **Liabilities and Equity** **Income Statement**

2015

Account Description	Account Number	2015 CGAAP TB	CGAAP to IFRS	2015 IFRS TB	Category
Cash	1005	3,084,294.04		3,084,294.04	1
Cash Advances and Working Funds	1010	-		-	
Interest Special Deposits	1020	-		-	
Dividend Special Deposits	1030	-		-	
Other Special Deposits	1040	-		-	
Term Deposits	1060	-		-	
Current Investments	1070	-		-	
Customer Accounts Receivable	1100	5,407,251.09		5,407,251.09	2
Accounts Receivable - Services	1102	-		-	2
Accounts Receivable - Recoverable Work	1104	292,255.89		292,255.89	2
Accounts Receivable - Merchandise, Jobbing, etc.	1105	-		-	2
Other Accounts Receivable	1110	200,828.48		200,828.48	2
Accrued Utility Revenues	1120	10,862,168.34		10,862,168.34	3
Accumulated Provision for Uncollectible Accounts--Credi	1130	-		-	
Interest and Dividends Receivable	1140	-		-	
Rents Receivable	1150	-		-	
Notes Receivable	1170	-		-	
Prepayments	1180	62,800.00		62,800.00	7
Miscellaneous Current and Accrued Assets	1190	-		-	
Accounts Receivable from Associated Companies	1200	436,883.46		436,883.46	4
Notes Receivable from Associated Companies	1210	-		-	
Fuel Stock	1305	-		-	
Plant Materials and Operating Supplies	1330	1,493,196.57		1,493,196.57	6
Merchandise	1340	-		-	
Other Materials and Supplies	1350	-		-	
Long Term Investments in Non-Associated Companies	1405	-		-	
Long Term Receivable - Street Lighting Transfer	1408	-		-	
Other Special or Collateral Funds	1410	-		-	
Sinking Funds	1415	-		-	
Unamortized Debt Expense	1425	-		-	
Unamortized Discount on Long-Term Debt--Debit	1445	-		-	
Unamortized Deferred Foreign Currency Translation Gai	1455	-		-	
Other Non-Current Assets	1460	(1,084,000.00)	(390,000.00)	(1,474,000.00)	22
O.M.E.R.S. Past Service Costs	1465	-		-	
Past Service Costs - Employee Future Benefits	1470	-		-	
Past Service Costs - Other Pension Plans	1475	-		-	
Portfolio Investments - Associated Companies	1480	-		-	
Investment in Associated Companies - Significant Influe	1485	-		-	
Investment in Subsidiary Companies	1490	-		-	
Unrecovered Plant and Regulatory Study Costs	1505	-		-	
Other Regulatory Assets	1508	(261,000.00)		(261,000.00)	21
Preliminary Survey and Investigation Charges	1510	-		-	
Emission Allowance Inventory	1515	-		-	
Emission Allowances Withheld	1516	-		-	
RCVARetail	1518	(119,374.55)		(119,374.55)	21
Power Purchase Variance Account	1520	-		-	
Special Purpose Charge Assessment Variance	1521	-		-	
Miscellaneous Deferred Debits	1525	-		-	
Deferred Losses from Disposition of Utility Plant	1530	-		-	
Renewable Connection Capital Deferral Account	1531	-		-	
Renewable Connection OM&A Deferral Account	1532	-		-	
Smart Grid Capital Deferral Account	1534	-		-	
Smart Grid Capital OM&A Account	1535	-		-	
Unamortized Loss on Reacquired Debt	1540	-		-	
Development Charge Deposits/ Receivables	1545	-		-	
RCVASTR	1548	68,466.06		68,466.06	21
LV Variance Account	1550	-		-	
Smart Meter Entity Charge Variance Account	1551	23,747.71		23,747.71	10
Smart Meter Capital and Recovery Offset Variance	1555	3,907.54		3,907.54	10
Smart Meter OM&A Variance	1556	-		-	
Deferred Development Costs	1560	-		-	
Deferred Payments in Lieu of Taxes	1562	-		-	
Deferred PILs Contra Account	1563	-		-	
Conservation and Demand Management Expenditures a	1565	-		-	
CDM Contra	1568	(10,354.56)		(10,354.56)	21
LRAM Variance Account	1570	-		-	
Qualifying Transition Costs	1570	-		-	
Pre-market Opening Energy Variance	1571	-		-	
Extraordinary Event Costs	1572	-		-	
Deferred Rate Impact Amounts	1574	-		-	
CGAAP Accounting Changes	1576	(72,874.00)		(72,874.00)	21
RSVAWMS	1580	(2,647,898.72)		(2,647,898.72)	21
RSVAONE-TIME	1582	-		-	
RSVANW	1584	238,600.69		238,600.69	21
RSVACN	1586	-		-	
RSVAPOWER	1588	(4,107,368.19)		(4,107,368.19)	21
RSVAGA	1589	1,545,719.38		1,545,719.38	21
Recovery of regulatory asset balances	1590	0.00		0.00	
2006 PILs & Taxes Variance	1592	-		-	
Disposition and Recovery of Regulatory Balances Contr	1595	(66,958.73)		(66,958.73)	Ref A
Electric Plant in Service - Control Account	1605	-	(10,844,534.72)	(10,844,534.72)	8
Organization	1606	-		-	
Franchises and Consents	1608	-		-	
Miscellaneous Intangible Plant	1610	-		-	
Land	1615	-		-	
Land Rights	1616	-		-	
Buildings and Fixtures	1620	-		-	
Leasehold Improvements	1630	-		-	
Boiler Plant Equipment	1635	-		-	
Engines and Engine-Driven Generators	1640	-		-	
Turbogenerator Units	1645	-		-	
Reservoirs, Dams and Waterways	1650	-		-	
Water Wheels, Turbines and Generators	1655	-		-	
Roads, Railroads and Bridges	1660	-		-	
Fuel Holders, Producers and Accessories	1665	-		-	
Prime Movers	1670	-		-	
Generators	1675	-		-	
Accessory Electric Equipment	1680	-		-	
Miscellaneous Power Plant Equipment	1685	-		-	
Land	1705	-		-	
Land Rights	1706	602,307.00		602,307.00	8
Buildings and Fixtures	1708	-		-	8
Leasehold Improvements	1710	-		-	8
Station Equipment	1715	-		-	8
Towers and Fixtures	1720	-		-	8
Poles and Fixtures	1725	1,759,070.54		1,759,070.54	8
Overhead Conductors and Devices	1730	84,490.48		84,490.48	8
Underground Conduit	1735	991,968.90		991,968.90	8
Underground Conductors and Devices	1740	238,716.32		238,716.32	8
Roads and Trails	1745	-		-	8
Land	1805	89,159.06		89,159.06	8
Land Rights	1806	166,619.52		166,619.52	8
Buildings and Fixtures	1808	26,290,728.36		26,290,728.36	8
Leasehold Improvements	1810	-		-	8
Transformer Station Equipment - Normally Primary abo	1815	9,723,183.65		9,723,183.65	8
Distribution Station Equipment - Normally Primary belo	1820	16,591,506.46		16,591,506.46	8
Storage Battery Equipment	1825	19,241.14		19,241.14	8
Poles, Towers and Fixtures	1830	19,238,495.92		19,238,495.92	8
Overhead Conductors and Devices	1835	16,063,190.10		16,063,190.10	8
Underground Conduit	1840	11,474,722.23		11,474,722.23	8
Underground Conductors and Devices	1845	21,531,935.90		21,531,935.90	8
Line Transformers	1850	19,137,365.51		19,137,365.51	8
Services	1855	5,805,285.21		5,805,285.21	8
Meters	1860	6,534,378.20		6,534,378.20	8
Other Installations on Customer's Premises	1865	-		-	
Leased Property on Customer Premises	1870	-		-	
Street Lighting and Signal Systems	1875	-		-	
Land	1905	-		-	
Land Rights	1906	-		-	
Buildings and Fixtures	1908	-		-	
Leasehold Improvements	1910	-		-	

2015 Audited Financial Statement Amounts For Balance Sheet and Income Statement

Balance Sheet	Sum of or portions of:	
Current Assets:		
Cash	1	3,084,294
Accounts Receivable	2	5,900,335
Unbilled Revenue	3	10,862,168
Due from Related Parties	4	436,883
Payment in Lieu of Taxes Recoverable	5	603,021
Inventory	6	1,493,197
Prepaid Expenses & Deposits	7	62,800
Total Current Assets		22,442,699
Non-current Assets:		
PP&E (net amortization)	8	87,309,571
Deferred Tax Assets	9	1,084,000
Total Non-current Assets		88,393,571
Total Assets		110,836,270
Regulatory Deferral Account Debit Balances	10	49,642
Deferred Tax Associated with Regulatory Deferral Account Balances	11	390,000
		439,642
Total Assets & Regulatory Deferral Account Debit Balances		**111,275,912**
Current Liabilities:		
Accounts Payable & Accrued Liabilities	12	(7,958,730)
Due to Related Parties	13	-
Current Portion of LT Debt	14	(15,785,022)
Customer Deposits	15	(922,422)
Deferred Revenue	16	(228,455)
Total Current Liabilities		(24,894,629)
Non-current Liabilities:		
Deferred Revenue	17	(1,119,671)
LT Debt	18	(50,380,538)
Total Non-current Liabilities		(51,500,209)
Total Liabilities		(76,394,837)
Shareholder`s Equity:		
Share Capital	19	(20,062,107)
Retained Earnings	20	(8,150,938)
Total Shareholder`s Equity		(28,213,045)
Total Liabilities & Shareholder`s Equity		**(104,607,882)**
Regulatory Deferral Account Credit Balances	21	(5,194,030)
Deferred Tax Liability Associated with Regulatory Deferral Account Balances	22	(1,474,000)
		(6,668,030)
Total Equity, Liabilities & Regulatory Deferral Account Credit Balances		**(111,275,912)**

Income Statement	Sum of or portions of:	
Electricity Sales	23	(79,708,094)
Distribution Revenue	24	(16,291,496)
Cost of Electricity Sold	25	73,275,057
		(22,724,533)
Other Operating Revenue	26	(3,640,802)
Net Operating Revenue		**(26,365,335)**
Expenses:		
Operations & Maintenance	27	5,977,598
General & Administrative	28	3,211,923
Billing & Collection	29	1,417,758
Depreciation & Amortization	30	4,139,746
Community Relations	31	1,529,216
		16,276,241
Income from Operating Activities		**(10,089,094)**
Other Expenses:		
Finance Income	32	(26,460)
Finance Charges	33	3,003,914
Net Finance Costs		**2,977,454**
Income (loss) Before Income Taxes		**(7,111,639)**
Income Tax Expense (Recovery)		
Current	34	1,285,959
Deferred	35	296,000
		1,581,959
Income (loss) for the Year Before Movements in Regulatory Deferral Account Balances		(5,529,680)
Net movement in Regulatory Deferral Account Balances related to Profit or Loss and the Related Deferred Tax Movement	36	4,641,680
Net Income, being Total Comprehensive Income for the Year		**(888,000)**

Office Furniture and Equipment	1915	-		-	
Computer Equipment - Hardware	1920	2,944.63		2,944.63	8
Computer Software	1925	60,490.73		60,490.73	8
Transportation Equipment	1930	-		-	
Stores Equipment	1935	-		-	
Tools, Shop and Garage Equipment	1940	-		-	
Measurement and Testing Equipment	1945	-		-	
Power Operated Equipment	1950	-		-	
Communication Equipment	1955	-		-	
Miscellaneous Equipment	1960	-		-	
Water Heater Rental Units	1965	-		-	
Load Management Controls - Customer Premises	1970	-		-	
Load Management Controls - Utility Premises	1975	-		-	
System Supervisory Equipment	1980	4,515,963.78		4,515,963.78	8
Sentinel Lighting Rental Units	1985	-		-	
Other Tangible Property	1990	-		-	
Contributions and Grants - Credit	1995	(11,964,206.09)	10,844,535.00	(1,119,671.09)	17
Property Under Capital Leases	2005	-		-	
Electric Plant Purchased or Sold	2010	-		-	
Experimental Electric Plant Unclassified	2020	-		-	
Electric Plant and Equipment Leased to Others	2030	-		-	
Electric Plant Held for Future Use	2040	-		-	
Completed Construction Not Classified--Electric	2050	-		-	
Construction Work in Progress--Electric	2055	-		-	
Electric Plant Acquisition Adjustment	2060	-		-	
Other Electric Plant Adjustment	2065	-		-	
Other Utility Plant	2070	-		-	
Non-Utility Property Owned or Under Capital Leases	2075	-		-	
Accumulated Amortization of Electric Utility Plan - PP&E	2105	(62,342,058.57)	(425,599.84)	(62,767,658.41)	8
Accumulated Amortization of Electric Utility Plant - Intar	2120	-		-	
Accumulated Amortization of Electric Plant Acquisition A	2140	-		-	
Accumulated Amortization of Other Utility Plant	2160	-		-	
Accumulated Amortization of Non-Utility Property	2180	-		-	
Accounts Payable	2205	(8,376,554.30)		(8,376,554.30)	12
Customer Credit Balances	2208	(0.05)		(0.05)	
Current Portion of Customer Deposits	2210	(922,422.20)		(922,422.20)	15
Dividends Declared	2215	-		-	
Miscellaneous Current and Accrued Liabilities	2220	(298,300.33)		(298,300.33)	Ref C
Notes and Loans Payable	2225	-		-	
Accounts Payable to Associated Companies	2240	-		-	
Notes Payable to Associated Companies	2242	-		-	
Debt Retirement Charges(DRC) Payable	2250	(123,673.83)		(123,673.83)	12
Transmission Charges Payable	2252	-		-	
Electrical Safety Authority Fees Payable	2254	-		-	
Independent Market Operator Fees and Penalties Payat	2256	-		-	
Current Portion of Long Term Debt	2260	(15,785,022.00)		(15,785,022.00)	14
Ontario Hydro Debt - Current Portion	2262	-		-	
Pensions and Employee Benefits - Current Portion	2264	-		-	
Accrued Interest on Long Term Debt	2268	(17,937.53)		(17,937.53)	12
Matured Long Term Debt	2270	-		-	
Matured Interest on Long Term Debt	2272	-		-	
Obligations Under Capital Leases--Current	2285	-		-	
Commodity Taxes	2290	629,281.51		629,281.51	12
Payroll Deductions / Expenses Payable	2292	-		-	
Accrual for Taxes Payments in Lieu of Taxes, Etc.	2294	603,021.35		603,021.35	5
Future Income Taxes - Current	2296	-		-	
Accumulated Provision for Injuries and Damages	2305	-		-	
Employee Future Benefits	2306	-		-	
Other Pensions - Past Service Liability	2308	-		-	
Vested Sick Leave Liability	2310	-		-	
Accumulated Provision for Rate Refunds	2315	-		-	
Other Miscellaneous Non-Current Liabilities	2320	-		-	
Obligations Under Capital Lease--Non-Current	2325	-		-	
Development Charge Fund	2330	-		-	
Long Term Customer Deposits	2335	-		-	
Collateral Funds Liability	2340	-		-	
Unamortized Premium on Long Term Debt	2345	-		-	
O.M.E.R.S. - Past Service Liability - Long Term Portion	2348	-		-	
Future Income Tax - Non-Current	2350	1,084,000.00	390,000.00	1,474,000.00	Ref B
Other Regulatory Liabilities	2405	-		-	
Deferred Gains from Disposition of Utility Plant	2410	-		-	
Unamortized Gain on Reacquired Debt	2415	-		-	
Other Deferred Credits	2425	261,000.00		261,000.00	21
Accrued Rate-Payer Benefit	2435	-		-	
Debentures Outstanding - Long Term Portion	2505	-		-	
Debenture Advances	2510	-		-	
Reacquired Bonds	2515	-		-	
Other Long Term Debt	2520	(23,846,497.71)		(23,846,497.71)	18
Term Bank Loans - Long Term Portion	2525	-		-	
Ontario Hydro Debt Outstanding - Long Term Portion	2530	-		-	
Advances from Associated Companies	2550	(26,534,040.00)		(26,534,040.00)	18
Common Shares Issued	3005	(20,062,106.65)		(20,062,106.65)	19
Preference Shares Issued	3008	-		-	
Contributed Surplus	3010	-		-	
Donations Received	3020	-		-	
Development Charges Transferred to Equity	3022	-		-	
Capital Stock Held in Treasury	3026	-		-	
Miscellaneous Paid-In Capital	3030	-		-	
Installments Received on Capital Stock	3035	-		-	
Appropriated Retained Earnings	3040	-		-	
Unappropriated Retained Earnings	3045	(7,548,123.11)	285,185.07	(7,262,938.04)	20
Balance Transferred From Income	3046	-		-	
Appropriations of Retained Earnings - Current Period	3047	-		-	
Dividends Payable-Preference Shares	3048	-		-	
Dividends Payable-Common Shares	3049	-		-	
Adjustment to Retained Earnings	3055	-		-	
Unappropriated Undistributed Subsidiary Earnings	3065	-		-	
Non-Utility Shareholders' Equity	3075	-		-	
Residential Energy Sales	4006	(31,985,149.33)		(31,985,149.33)	23
Commercial Energy Sales	4010	-		-	
Industrial Energy Sales	4015	-		-	
Energy Sales to Large Users	4020	-		-	
Street Lighting Energy Sales	4025	(797,539.83)		(797,539.83)	23
Sentinel Lighting Energy Sales	4030	(25,550.14)		(25,550.14)	23
General Energy Sales	4035	(36,303,241.29)		(36,303,241.29)	23
Other Energy Sales to Public Authorities	4040	-		-	
Energy Sales to Railroads and Railways	4045	-		-	
Revenue Adjustment	4050	-		-	
Energy Sales for Resale	4055	(1,773,123.91)		(1,773,123.91)	23
Interdepartmental Energy Sales	4060	-		-	
Billed WMS	4062	(2,555,858.63)		(2,555,858.63)	Ref D
Billed One-Time	4064	-		-	
Billed NW	4066	(4,357,670.94)		(4,357,670.94)	Ref E
Billed CN	4068	-		-	
Billed - LV	4075	-		-	
Billed - Smart Meter Entity Charge	4076	(312,254.29)		(312,254.29)	23
Distribution Services Revenue	4080	(16,412,844.48)		(16,412,844.48)	Ref F
Retail Services Revenues	4082	(27,320.80)		(27,320.80)	26
Service Transaction Requests (STR) Revenues	4084	(360.25)		(360.25)	26
Electric Services Incidental to Energy Sales	4090	-		-	
Transmission Charges Revenue	4105	-		-	
Transmission Services Revenue	4110	-		-	
Interdepartmental Rents	4205	-		-	
Rent from Electric Property	4210	(1,628,386.54)		(1,628,386.54)	26
Other Utility Operating Income	4215	-		-	
Other Electric Revenues	4220	-		-	
Late Payment Charges	4225	(246,556.74)		(246,556.74)	26
Sales of Water and Water Power	4230	-		-	
Miscellaneous Service Revenues	4235	(291,423.51)		(291,423.51)	26
Provision for Rate Refunds	4240	-		-	
Government Assistance Directly Credited to Income	4245	-		-	
Regulatory Debits	4305	-		-	
Regulatory Credits	4310	-		-	
Revenues from Electric Plant Leased to Others	4315	-		-	
Expenses of Electric Plant Leased to Others	4320	-		-	
Special Purpose Charge Recovery	4324	-		-	
Revenues from Merchandise, Jobbing, Etc.	4325	(80,940.92)		(80,940.92)	26
Costs and Expenses of Merchandising, Jobbing, Etc.	4330	12,050.10		12,050.10	26
Profits and Losses from Financial Instrument Hedges	4335	-		-	
Profits and Losses from Financial Instrument Investmer	4340	-		-	
Gains from Disposition of Future Use Utility Plant	4345	-		-	
Losses from Disposition of Future Use Utility Plant	4350	-		-	
Gain on Disposition of Utility and Other Property	4355	-		-	
Loss on Disposition of Utility and Other Property	4360	-		-	

Gains from Disposition of Allowances for Emission	4365	-	-	
Losses from Disposition of Allowances for Emission	4370	-	-	
Revenues from Non-Utility Operations	4375	(1,110,896.53)	(1,110,896.53)	**26**
Expenses of Non-Utility Operations	4380	858,672.09	858,672.09	**31**
Non-Utility Rental Income	4385	-	-	
Miscellaneous Non-Operating Income	4390	(35,228.62)	(35,228.62)	**26**
Rate-Payer Benefit Including Interest	4395	-	-	
Foreign Exchange Gains and Losses, Including Amortiza	4398	-	-	
Interest and Dividend Income	4405	(26,459.60)	(26,459.60)	**32**
Equity in Earnings of Subsidiary Companies	4415	-	-	
Operation Supervision and Engineering	4505	-	-	
Fuel	4510	-	-	
Steam Expense	4515	-	-	
Steam From Other Sources	4520	-	-	
Steam Transferred--Credit	4525	-	-	
Electric Expense	4530	-	-	
Water For Power	4535	-	-	
Water Power Taxes	4540	-	-	
Hydraulic Expenses	4545	-	-	
Generation Expense	4550	-	-	
Miscellaneous Power Generation Expenses	4555	-	-	
Rents	4560	-	-	
Allowances for Emissions	4565	-	-	
Maintenance Supervision and Engineering	4605	-	-	
Maintenance of Structures	4610	-	-	
Maintenance of Boiler Plant	4615	-	-	
Maintenance of Electric Plant	4620	-	-	
Maintenance of Reservoirs, Dams and Waterways	4625	-	-	
Maintenance of Water Wheels, Turbines and Generators	4630	-	-	
Maintenance of Generating and Electric Plant	4635	-	-	
Maintenance of Miscellaneous Power Generation Plant	4640	-	-	
Power Purchased	4705	50,769,484.61	50,769,484.61	**Ref G**
Charges - Global Adjustment	4707	20,115,120.18	20,115,120.18	**36**
Charges-WMS	4708	2,555,858.63	2,555,858.63	**25**
Cost of Power Adjustments	4710	-	-	
Charges-One-Time	4712	-	-	
Charges-NW	4714	4,357,670.94	4,357,670.94	**25**
System Control and Load Dispatching	4715	-	-	
Charges-CN	4716	-	-	
Other Expenses	4720	-	-	
Competition Transition Expense	4725	-	-	
Rural Rate Assistance Expense	4730	-	-	
Charges - LV	4750	-	-	
Charges - Smart Metering Entity Charge	4751	312,254.29	312,254.29	**Ref H**
Operation Supervision and Engineering	4805	-	-	
Load Dispatching	4810	-	-	
Station Buildings and Fixtures Expenses	4815	40,955.33	40,955.33	**27**
Transformer Station Equipment - Operating Labour	4820	-	-	
Transformer Station Equipment - Operating Supplies an	4825	-	-	
Overhead Line Expenses	4830	-	-	
Underground Line Expenses	4835	-	-	
Transmission of Electricity by Others	4840	-	-	
Miscellaneous Transmission Expense	4845	-	-	
Rents	4850	-	-	
Maintenance Supervision and Engineering	4905	-	-	
Maintenance of Transformer Station Buildings and Fixtu	4910	-	-	
Maintenance of Transformer Station Equipment	4916	-	-	
Maintenance of Towers, Poles and Fixtures	4930	-	-	
Maintenance of Overhead Conductors and Devices	4935	-	-	
Maintenance of Overhead Lines - Right of Way	4940	-	-	
Maintenance of Overhead Lines - Roads and Trails Repa	4945	-	-	
Maintenance of Overhead Lines - Snow Removal from F	4950	-	-	
Maintenance of Underground Lines	4960	-	-	
Maintenance of Miscellaneous Transmission Plant	4965	-	-	
Operation Supervision and Engineering	5005	661,002.53	661,002.53	**27**
Load Dispatching	5010	223,193.58	223,193.58	**27**
Station Buildings and Fixtures Expense	5012	608,388.26	608,388.26	**27**
Transformer Station Equipment - Operation Labour	5014	64,518.54	64,518.54	**27**
Transformer Station Equipment - Operation Supplies an	5015	9,084.68	9,084.68	**27**
Distribution Station Equipment - Operation Labour	5016	44,493.07	44,493.07	**27**
Distribution Station Equipment - Operation Supplies and	5017	21,127.82	21,127.82	**27**
Overhead Distribution Lines and Feeders - Operation La	5020	598,189.90	598,189.90	**27**
Overhead Distribution Lines and Feeders - Operation Su	5025	133,936.23	133,936.23	**27**
Overhead Subtransmission Feeders - Operation	5030	1,925.31	1,925.31	**27**
Overhead Distribution Transformers- Operation	5035	753.59	753.59	**27**
Underground Distribution Lines and Feeders - Operation	5040	166,632.06	166,632.06	**27**
Underground Distribution Lines and Feeders - Operation	5045	27,320.16	27,320.16	**27**
Underground Subtransmission Feeders - Operation	5050	403.14	403.14	**27**
Underground Distribution Transformers - Operation	5055	3,230.39	3,230.39	**27**
Street Lighting and Signal System Expense	5060	-	-	
Meter Expense	5065	294,315.75	294,315.75	**27**
Customer Premises - Operation Labour	5070	150,213.89	150,213.89	**27**
Customer Premises - Materials and Expenses	5075	41,257.68	41,257.68	**27**
Miscellaneous Distribution Expense	5085	512,348.67	512,348.67	**27**
Underground Distribution Lines and Feeders - Rental Pa	5090	52.67	52.67	**27**
Overhead Distribution Lines and Feeders - Rental Paid	5095	8,202.12	8,202.12	**27**
Other Rent	5096	91,403.54	91,403.54	**27**
Maintenance Supervision and Engineering	5105	-	-	
Maintenance of Buildings and Fixtures - Distribution Sta	5110	224,709.95	224,709.95	**27**
Maintenance of Transformer Station Equipment	5112	91,106.68	91,106.68	**27**
Maintenance of Distribution Station Equipment	5114	35,138.14	35,138.14	**27**
Maintenance of Poles, Towers and Fixtures	5120	56,457.33	56,457.33	**27**
Maintenance of Overhead Conductors and Devices	5125	522,241.70	522,241.70	**27**
Maintenance of Overhead Conductors	5126	-	-	**27**
Maintenance of Overhead Services	5130	67,297.15	67,297.15	**27**
Overhead Distribution Lines and Feeders - Right of Way	5135	642,041.93	642,041.93	**27**
Maintenance of Underground Conduit	5145	91,315.39	91,315.39	**27**
Maintenance of Underground Conductors and Devices	5150	169,953.82	169,953.82	**27**
Maintenance of Underground Services	5155	81,651.14	81,651.14	**27**
Maintenance of Line Transformers	5160	211,053.87	211,053.87	**27**
Maintenance of Street Lighting and Signal Systems	5165	-	-	
Sentinel Lights - Labour	5170	-	-	
Sentinel Lights - Materials and Expenses	5172	-	-	
Maintenance of Meters	5175	81,681.84	81,681.84	**27**
Customer Installations Expenses- Leased Property	5178	-	-	
Water Heater Rentals - Labour	5185	-	-	
Water Heater Rentals - Materials and Expenses	5186	-	-	
Water Heater Controls - Labour	5190	-	-	
Water Heater Controls - Materials and Expenses	5192	-	-	
Maintenance of Other Installations on Customer Premis	5195	-	-	
Purchase of Transmission and System Services	5205	-	-	
Transmission Charges	5210	-	-	
Transmission Charges Recovered	5215	-	-	
Supervision	5305	48,437.89	48,437.89	**29**
Meter Reading Expense	5310	337,646.28	337,646.28	**29**
Customer Billing	5315	501,949.29	501,949.29	**29**
Collecting	5320	348,403.51	348,403.51	**29**
Collecting- Cash Over and Short	5325	-	-	
Collection Charges	5330	-	-	
Bad Debt Expense	5335	181,321.21	181,321.21	**29**
Miscellaneous Customer Accounts Expenses	5340	-	-	
Supervision	5405	59,942.43	59,942.43	**31**
Community Relations - Sundry	5410	582,621.34	582,621.34	**31**
Energy Conservation	5415	-	-	
Community Safety Program	5420	27,980.49	27,980.49	**31**
Miscellaneous Customer Service and Informational Expe	5425	-	-	
Supervision	5505	-	-	
Demonstrating and Selling Expense	5510	-	-	
Advertising Expense	5515	-	-	
Miscellaneous Sales Expense	5520	-	-	
Executive Salaries and Expenses	5605	366,005.91	366,005.91	**28**
Management Salaries and Expenses	5610	520,921.26	520,921.26	**28**
General Administrative Salaries and Expenses	5615	392,407.26	392,407.26	**28**
Office Supplies and Expenses	5620	413,553.31	413,553.31	**28**
Administrative Expense Transferred/Credit	5625	-	-	
Outside Services Employed	5630	227,541.99	227,541.99	**28**
Property Insurance	5635	205,612.26	205,612.26	**28**
Injuries and Damages	5640	-	-	
Employee Pensions and Benefits	5645	-	-	
Franchise Requirements	5650	-	-	
Regulatory Expenses	5655	149,855.77	149,855.77	**28**
General Advertising Expenses	5660	-	-	
Miscellaneous General Expenses	5665	223,160.74	223,160.74	**28**
Rent	5670	-	-	

Maintenance of General Plant	5675	653,778.49		653,778.49	**28**
Electrical Safety Authority Fees	5680	-		-	
Special Purpose Charge Expense	5681	-		-	
Independent Market Operator Fees and Penalties	5685	-		-	
OM&A Contra	5695	-		-	
Amortization Expense - Property, Plant, and Equipment	5705	4,316,535.96	(176,789.69)	4,139,746.27	**30**
Amortization of Limited Term Electric Plant	5710	-		-	
Amortization of Intangibles and Other Electric Plant	5715	-		-	
Amortization of Electric Plant Acquisition Adjustments	5720	-		-	
Miscellaneous Amortization	5725	(427,593.74)	317,204.46	(110,389.28)	**26**
Amortization of Unrecovered Plant and Regulatory Stud	5730	-		-	
Amortization of Deferred Development Costs	5735	-		-	
Amortization of Deferred Charges	5740	-		-	
Interest on Long Term Debt	6005	1,320,477.00		1,320,477.00	**33**
Amortization of Debt Discount and Expense	6010	-		-	
Amortization of Premium on Debt/Credit	6015	-		-	
Amortization of Loss on Reacquired Debt	6020	-		-	
Amortization of Gain on Reacquired Debt--Credit	6025	-		-	
Interest on Debt to Associated Companies	6030	1,618,623.35		1,618,623.35	**33**
Other Interest Expense	6035	64,813.46		64,813.46	**33**
Allowance for Borrowed Funds Used During Constructio	6040	-		-	
Allowance For Other Funds Used During Construction	6042	-		-	
Interest Expense on Capital Lease Obligations	6045	-		-	
Taxes Other Than Income Taxes	6105	36,159.57		36,159.57	**28**
Income Taxes	6110	(505,398.00)		(505,398.00)	**Ref I**
Provision for Future Income Taxes	6115	296,000.00		296,000.00	**35**
Regulatory Deferral PILs Adjustment	6120	-		-	
Donations	6205	22,926.00		22,926.00	**28**
Life Insurance	6210	-		-	
Penalties	6215	-		-	
Other Deductions	6225	-		-	
Extraordinary Income	6305	-		-	
Extraordinary Deductions	6310	-		-	
Income Taxes: Extraordinary Item	6315	-		-	
Discontinues Operations - Income/ Gains	6405	-		-	
Discontinued Operations - Deductions/ Losses	6410	-		-	
Income Taxes, Discontinued Operations	6415	-		-	
		0	**0**	**0**	

		(58,402.00)	**21**
		(30,544.00)	**21**
		21,987.00	**10**
	Ref A	(66,959.00)	
		390,000.00	**11**
		1,084,000.00	**9**
	Ref B	1,474,000.00	
		(228,454.65)	**16**
		(69,845.68)	**12**
	Ref C	(298,300.33)	
		(4,075,719.32)	**23**
		1,519,860.69	**36**
	Ref D	(2,555,858.63)	
		(4,435,515.64)	**23**
		77,844.70	**36**
	Ref E	(4,357,670.94)	
		(16,291,495.52)	**24**
		(121,348.96)	**26**
	Ref F	(16,412,844.48)	
		66,049,396.27	**25**
		(15,279,911.66)	**36**
	Ref G	50,769,484.61	
		312,130.72	**25**
		123.57	**36**
	Ref H	312,254.29	
		1,285,959.00	**34**
		(1,791,357.00)	**36**
	Ref I	(505,398.00)	

Color Legend: **Assets** **Liabilities and Equity**

2016

Account Description	Account Number	2016 IFRS TB	Category
Cash	1005	3,999,921.76	Ref A
Cash Advances and Working Funds	1010	-	
Interest Special Deposits	1020	-	
Dividend Special Deposits	1030	-	
Other Special Deposits	1040	-	
Term Deposits	1060	-	
Current Investments	1070	-	
Customer Accounts Receivable	1100	6,098,791.97	2
Accounts Receivable - Services	1102	-	
Accounts Receivable - Recoverable Work	1104	308,491.03	2
Accounts Receivable - Merchandise, Jobbing, etc.	1105	-	
Other Accounts Receivable	1110	212,986.57	2
Accrued Utility Revenues	1120	10,175,781.75	3
Accumulated Provision for Uncollectible Accounts--Cred	1130	-	
Interest and Dividends Receivable	1140	-	
Rents Receivable	1150	-	
Notes Receivable	1170	-	
Prepayments	1180	63,400.00	7
Miscellaneous Current and Accrued Assets	1190	-	
Accounts Receivable from Associated Companies	1200	-	
Notes Receivable from Associated Companies	1210	-	
Fuel Stock	1305	-	
Plant Materials and Operating Supplies	1330	1,486,453.34	6
Merchandise	1340	-	
Other Materials and Supplies	1350	-	
Long Term Investments in Non-Associated Companies	1405	-	
Long Term Receivable - Street Lighting Transfer	1408	-	
Other Special or Collateral Funds	1410	-	
Sinking Funds	1415	-	
Unamortized Debt Expense	1425	-	
Unamortized Discount on Long-Term Debt--Debit	1445	-	
Unamortized Deferred Foreign Currency Translation Gai	1455	-	
Other Non-Current Assets	1460	(1,081,000.00)	Ref C
O.M.E.R.S. Past Service Costs	1465	-	
Past Service Costs - Employee Future Benefits	1470	-	
Past Service Costs - Other Pension Plans	1475	-	
Portfolio Investments - Associated Companies	1480	-	
Investment in Associated Companies - Significant Influe	1485	-	
Investment in Subsidiary Companies	1490	-	
Unrecovered Plant and Regulatory Study Costs	1505	-	
Other Regulatory Assets	1508	(365,400.00)	21
Preliminary Survey and Investigation Charges	1510	-	
Emission Allowance Inventory	1515	-	
Emission Allowances Withheld	1516	-	
RCVARetail	1518	(144,622.09)	21
Power Purchase Variance Account	1520	-	
Special Purpose Charge Assessment Variance	1521	-	
Miscellaneous Deferred Debits	1525	-	
Deferred Losses from Disposition of Utility Plant	1530	-	
Renewable Connection Capital Deferral Account	1531	-	
Renewable Connection OM&A Deferral Account	1532	-	
Smart Grid Capital Deferral Account	1534	-	
Smart Grid Capital OM&A Account	1535	-	
Unamortized Loss on Reacquired Debt	1540	-	
Development Charge Deposits/ Receivables	1545	-	
RCVASTR	1548	81,104.78	21
LV Variance Account	1550	-	
Smart Meter Entity Charge Variance Account	1551	35,267.94	10
Smart Meter Capital and Recovery Offset Variance	1555	3,846.79	10
Smart Meter OM&A Variance	1556	-	
Deferred Development Costs	1560	-	
Deferred Payments in Lieu of Taxes	1562	-	
Deferred PILs Contra Account	1563	-	
Conservation and Demand Management Expenditures a	1565	-	
CDM Contra	1568	(10,502.04)	21
LRAM Variance Account	1570	-	
Qualifying Transition Costs	1570	-	
Pre-market Opening Energy Variance	1571	-	
Extraordinary Event Costs	1572	-	
Deferred Rate Impact Amounts	1574	-	
CGAAP Accounting Changes	1576	2.00	21
RSVAWMS	1580	(2,397,926.31)	21
RSVAONE-TIME	1582	-	
RSVANW	1584	(97,019.94)	21
RSVACN	1586	-	
RSVAPOWER	1588	(605,419.53)	21
RSVAGA	1589	117,098.64	21
Recovery of regulatory asset balances	1590	-	
2006 PILs & Taxes Variance	1592	-	
Disposition and Recovery of Regulatory Balances Contr	1595	569,639.85	Ref B
Electric Plant in Service - Control Account	1605	-	
Organization	1606	-	
Franchises and Consents	1608	-	
Miscellaneous Intangible Plant	1610	-	
Computer Software	1611	48,838.09	8
Land Rights	1612	173,683.64	8
Land	1615	-	
Land Rights	1616	-	
Buildings and Fixtures	1620	-	
Leasehold Improvements	1630	-	
Boiler Plant Equipment	1635	-	
Engines and Engine-Driven Generators	1640	-	
Turbogenerator Units	1645	-	
Reservoirs, Dams and Waterways	1650	-	
Water Wheels, Turbines and Generators	1655	-	
Roads, Railroads and Bridges	1660	-	
Fuel Holders, Producers and Accessories	1665	-	
Prime Movers	1670	-	
Generators	1675	-	
Accessory Electric Equipment	1680	-	
Miscellaneous Power Plant Equipment	1685	-	
Land	1705	-	
Land Rights	1706	602,307.00	8
Buildings and Fixtures	1708	-	
Leasehold Improvements	1710	-	
Station Equipment	1715	-	
Towers and Fixtures	1720	-	
Poles and Fixtures	1725	2,052,903.04	8
Overhead Conductors and Devices	1730	84,490.48	8
Underground Conduit	1735	935,416.92	8
Underground Conductors and Devices	1740	228,053.43	8
Roads and Trails	1745	-	
Land	1805	89,159.06	8
Land Rights	1806	-	
Buildings and Fixtures	1808	25,018,231.27	8
Leasehold Improvements	1810	-	
Transformer Station Equipment - Normally Primary abo	1815	6,482,899.98	8
Distribution Station Equipment - Normally Primary belo	1820	10,199,772.71	8
Storage Battery Equipment	1825	13,721.69	8
Poles, Towers and Fixtures	1830	12,953,353.36	8
Overhead Conductors and Devices	1835	9,758,124.22	8
Underground Conduit	1840	1,324,499.03	8
Underground Conductors and Devices	1845	10,065,639.00	8
Line Transformers	1850	9,912,658.97	8
Services	1855	6,063,049.50	8

2016 Audited Financial Statement Amounts For Balance Sheet and Income Statement

Balance Sheet		Sum of or portions of:	
Current Assets:			
Cash & Cash Equivalents	Ref A	1	3,899,721
Accounts Receivable		2	6,620,270
Unbilled Revenue		3	10,175,782
Due from Related Parties	Ref A	4	100,201
Payment in Lieu of Taxes Recoverable		5	550,032
Inventory		6	1,486,453
Prepaid Expenses & Deposits		7	63,400
Total Current Assets			22,895,859
Non-current Assets:			
PP&E (net amortization)		8	89,413,227
Deferred Tax Assets		9	1,081,000
Total Non-current Assets			90,494,227
Total Assets			113,390,085
Regulatory Deferral Account Debit Balances	Ref B	10	698,439
Deferred Tax Associated with Regulatory Deferral Account Balances	Ref C	11	390,000
			1,088,439
Total Assets & Regulatory Deferral Account Debit Balances			**114,478,524**
Current Liabilities:			
Accounts Payable & Accrued Liabilities	Ref D	12	(13,766,619)
Due to Related Parties		13	-
Current Portion of LT Debt	Ref E	14	(1,211,084)
Customer Deposits		15	(987,485)
Deferred Revenue	Ref D	16	(207,980)
Total Current Liabilities			(16,173,168)
Non-current Liabilities:			
Deferred Revenue		17	(1,847,591)
LT Debt	Ref E	18	(63,947,191)
Total Non-current Liabilities			(65,794,782)
Total Liabilities			(81,967,950)
Shareholder`s Equity:			
Share Capital		19	(20,062,107)
Retained Earnings		20	(7,830,499)
Total Shareholder`s Equity			(27,892,606)
Total Liabilities & Shareholder`s Equity			**(109,860,556)**
Regulatory Deferral Account Credit Balances	Ref B	21	(3,146,969)
Deferred Tax Liability Associated with Regulatory Deferral Account Balances	Ref C	22	(1,471,000)
			(4,617,969)
Total Equity, Liabilities & Regulatory Deferral Account Credit Balances			**(114,478,525)**

Income Statement		Sum of or portions of:	
Electricity Sales	Ref F/Ref G/Ref H	23	(82,764,200)
Distribution Revenue	Ref I	24	(15,495,940)
Cost of Electricity Sold	Ref J	25	81,410,411
			(16,849,729)
Other Operating Revenue	Ref I	26	(3,493,755)
Net Operating Revenue			**(20,343,484)**
Expenses:			
Operations & Maintenance		27	5,977,871
General & Administrative		28	3,188,235
Billing & Collection		29	1,572,173
Depreciation & Amortization		30	4,202,174
Community Relations		31	1,388,930
			16,329,384
Income from Operating Activities			**(4,014,099)**
Other Expenses:			
Finance Income		32	(33,313)
Finance Charges		33	3,058,063
Net Finance Costs			**3,024,750**
Income (loss) Before Income Taxes			**(989,349)**
Income Tax Expense (Recovery)			
Current		34	(44,000)
Deferred	Ref K	35	3,000
			(41,000)
Income (loss) for the Year Before Movements in Regulatory Deferral Account Balances			(1,030,349)
Net movement in Regulatory Deferral Account Balances related to Profit or Loss	Ref F/Ref G/Ref H/Ref J	36	1,353,788
Income Tax	Ref K	37	(3,000)
Net Loss (Income), being Total Comprehensive Loss (Income) for the Year			**320,439**

Meters	1860	3,970,589.64	8
Other Installations on Customer's Premises	1865	-	
Leased Property on Customer Premises	1870	-	
Street Lighting and Signal Systems	1875	-	
Land	1905	-	
Land Rights	1906	-	
Buildings and Fixtures	1908	-	
Leasehold Improvements	1910	-	
Office Furniture and Equipment	1915	-	
Computer Equipment - Hardware	1920	1,360.87	8
Computer Software	1925	-	
Transportation Equipment	1930	-	
Stores Equipment	1935	-	
Tools, Shop and Garage Equipment	1940	-	
Measurement and Testing Equipment	1945	-	
Power Operated Equipment	1950	-	
Communication Equipment	1955	-	
Miscellaneous Equipment	1960	-	
Water Heater Rental Units	1965	-	
Load Management Controls - Customer Premises	1970	-	
Load Management Controls - Utility Premises	1975	-	
System Supervisory Equipment	1980	1,506,997.76	8
Sentinel Lighting Rental Units	1985	-	
Other Tangible Property	1990	-	
Contributions and Grants - Credit	1995	(1,847,591.06)	17
Property Under Capital Leases	2005	-	
Electric Plant Purchased or Sold	2010	-	
Experimental Electric Plant Unclassified	2020	-	
Electric Plant and Equipment Leased to Others	2030	-	
Electric Plant Held for Future Use	2040	-	
Completed Construction Not Classified--Electric	2050	-	
Construction Work in Progress--Electric	2055	-	
Electric Plant Acquisition Adjustment	2060	-	
Other Electric Plant Adjustment	2065	-	
Other Utility Plant	2070	-	
Non-Utility Property Owned or Under Capital Leases	2075	-	
Accumulated Amortization of Electric Utility Plan - PP&E	2105	(12,072,523.15)	8
Accumulated Amortization of Electric Utility Plant - Inta	2120	-	
Accumulated Amortization of Electric Plant Acquisition A	2140	-	
Accumulated Amortization of Other Utility Plant	2160	-	
Accumulated Amortization of Non-Utility Property	2180	-	
Accounts Payable	2205	(14,386,982.09)	12
Customer Credit Balances	2208	(0.05)	12
Current Portion of Customer Deposits	2210	(987,485.10)	15
Dividends Declared	2215	-	
Miscellaneous Current and Accrued Liabilities	2220	(273,493.16)	Ref D
Notes and Loans Payable	2225	-	
Accounts Payable to Associated Companies	2240	-	
Notes Payable to Associated Companies	2242	-	
Debt Retirement Charges(DRC) Payable	2250	(46,800.81)	12
Transmission Charges Payable	2252	-	
Electrical Safety Authority Fees Payable	2254	-	
Independent Market Operator Fees and Penalties Payat	2256	-	
Current Portion of Long Term Debt	2260	-	
Ontario Hydro Debt - Current Portion	2262	-	
Pensions and Employee Benefits - Current Portion	2264	-	
Accrued Interest on Long Term Debt	2268	-	
Matured Long Term Debt	2270	-	
Matured Interest on Long Term Debt	2272	-	
Obligations Under Capital Leases--Current	2285	-	
Commodity Taxes	2290	732,677.19	12
Payroll Deductions / Expenses Payable	2292	-	
Accrual for Taxes Payments in Lieu of Taxes, Etc.	2294	550,032.35	5
Future Income Taxes - Current	2296	-	
Accumulated Provision for Injuries and Damages	2305	-	
Employee Future Benefits	2306	-	
Other Pensions - Past Service Liability	2308	-	
Vested Sick Leave Liability	2310	-	
Accumulated Provision for Rate Refunds	2315	-	
Other Miscellaneous Non-Current Liabilities	2320	-	
Obligations Under Capital Lease--Non-Current	2325	-	
Development Charge Fund	2330	-	
Long Term Customer Deposits	2335	-	
Collateral Funds Liability	2340	-	
Unamortized Premium on Long Term Debt	2345	-	
O.M.E.R.S. - Past Service Liability - Long Term Portion	2348	-	
Future Income Tax - Non-Current	2350	1,081,000.00	9
Other Regulatory Liabilities	2405	-	
Deferred Gains from Disposition of Utility Plant	2410	-	
Unamortized Gain on Reacquired Debt	2415	-	
Other Deferred Credits	2425	365,400.00	21
Accrued Rate-Payer Benefit	2435	-	
Debentures Outstanding - Long Term Portion	2505	-	
Debenture Advances	2510	-	
Reacquired Bonds	2515	-	
Other Long Term Debt	2520	(38,624,234.78)	Ref E
Term Bank Loans - Long Term Portion	2525	-	
Ontario Hydro Debt Outstanding - Long Term Portion	2530	-	
Advances from Associated Companies	2550	(26,534,040.00)	Ref E
Common Shares Issued	3005	(20,062,106.65)	19
Preference Shares Issued	3008	-	
Contributed Surplus	3010	-	
Donations Received	3020	-	
Development Charges Transferred to Equity	3022	-	
Capital Stock Held in Treasury	3026	-	
Miscellaneous Paid-In Capital	3030	-	
Installments Received on Capital Stock	3035	-	
Appropriated Retained Earnings	3040	-	
Unappropriated Retained Earnings	3045	(8,150,937.90)	20
Balance Transferred From Income	3046	-	
Appropriations of Retained Earnings - Current Period	3047	-	
Dividends Payable-Preference Shares	3048	-	
Dividends Payable-Common Shares	3049	-	
Adjustment to Retained Earnings	3055	-	
Unappropriated Undistributed Subsidiary Earnings	3065	-	
Non-Utility Shareholders' Equity	3075	-	
Residential Energy Sales	4006	(57,326,746.55)	Ref F
Commercial Energy Sales	4010	-	
Industrial Energy Sales	4015	-	
Energy Sales to Large Users	4020	-	
Street Lighting Energy Sales	4025	(635,219.31)	23
Sentinel Lighting Energy Sales	4030	(28,269.18)	23
General Energy Sales	4035	(39,641,147.86)	23
Other Energy Sales to Public Authorities	4040	-	
Energy Sales to Railroads and Railways	4045	-	
Revenue Adjustment	4050	-	
Energy Sales for Resale	4055	(1,298,215.95)	23
Interdepartmental Energy Sales	4060	-	
Billed WMS	4062	(3,062,528.74)	Ref G
Billed One-Time	4064	-	
Billed NW	4066	(4,066,893.18)	Ref H
Billed CN	4068	-	
Billed - LV	4075	-	
Billed - Smart Meter Entity Charge	4076	(302,117.18)	23
Distribution Services Revenue	4080	(15,614,779.81)	Ref I
Retail Services Revenues	4082	(23,850.40)	26
Service Transaction Requests (STR) Revenues	4084	(274.75)	26
Electric Services Incidental to Energy Sales	4090	-	
Transmission Charges Revenue	4105	-	
Transmission Services Revenue	4110	-	
Interdepartmental Rents	4205	-	
Rent from Electric Property	4210	(1,731,776.77)	26
Other Utility Operating Income	4215	-	
Other Electric Revenues	4220	-	
Late Payment Charges	4225	(177,224.77)	26
Sales of Water and Water Power	4230	-	
Miscellaneous Service Revenues	4235	(316,018.60)	26

Provision for Rate Refunds	4240	-	
Government Assistance Directly Credited to Income	4245	-	
Regulatory Debits	4305	-	
Regulatory Credits	4310	-	
Revenues from Electric Plant Leased to Others	4315	-	
Expenses of Electric Plant Leased to Others	4320	-	
Special Purpose Charge Recovery	4324	-	
Revenues from Merchandise, Jobbing, Etc.	4325	(229,684.76)	**26**
Costs and Expenses of Merchandising, Jobbing, Etc.	4330	2,507.11	**26**
Profits and Losses from Financial Instrument Hedges	4335	-	
Profits and Losses from Financial Instrument Investmer	4340	-	
Gains from Disposition of Future Use Utility Plant	4345	-	
Losses from Disposition of Future Use Utility Plant	4350	-	
Gain on Disposition of Utility and Other Property	4355	-	
Loss on Disposition of Utility and Other Property	4360	-	
Gains from Disposition of Allowances for Emission	4365	-	
Losses from Disposition of Allowances for Emission	4370	-	
Revenues from Non-Utility Operations	4375	(766,821.92)	**26**
Expenses of Non-Utility Operations	4380	762,272.73	**31**
Non-Utility Rental Income	4385	-	
Miscellaneous Non-Operating Income	4390	(19,337.84)	**26**
Rate-Payer Benefit Including Interest	4395	-	
Foreign Exchange Gains and Losses, Including Amortiza	4398	-	
Interest and Dividend Income	4405	(33,313.18)	**32**
Equity in Earnings of Subsidiary Companies	4415	-	
Operation Supervision and Engineering	4505	-	
Fuel	4510	-	
Steam Expense	4515	-	
Steam From Other Sources	4520	-	
Steam Transferred--Credit	4525	-	
Electric Expense	4530	-	
Water For Power	4535	-	
Water Power Taxes	4540	-	
Hydraulic Expenses	4545	-	
Generation Expense	4550	-	
Miscellaneous Power Generation Expenses	4555	-	
Rents	4560	-	
Allowances for Emissions	4565	-	
Maintenance Supervision and Engineering	4605	-	
Maintenance of Structures	4610	-	
Maintenance of Boiler Plant	4615	-	
Maintenance of Electric Plant	4620	-	
Maintenance of Reservoirs, Dams and Waterways	4625	-	
Maintenance of Water Wheels, Turbines and Generators	4630	-	
Maintenance of Generating and Electric Plant	4635	-	
Maintenance of Miscellaneous Power Generation Plant	4640	-	
Power Purchased	4705	73,967,927.06	**25**
Charges - Global Adjustment	4707	24,961,671.79	**36**
Charges-WMS	4708	3,062,528.74	**25**
Cost of Power Adjustments	4710	-	
Charges-One-Time	4712	-	
Charges-NW	4714	4,066,893.18	**25**
System Control and Load Dispatching	4715	-	
Charges-CN	4716	-	
Other Expenses	4720	-	
Competition Transition Expense	4725	-	
Rural Rate Assistance Expense	4730	-	
Charges - LV	4750	-	
Charges - Smart Metering Entity Charge	4751	302,117.18	**Ref J**
Operation Supervision and Engineering	4805	-	
Load Dispatching	4810	-	
Station Buildings and Fixtures Expenses	4815	50,381.46	**27**
Transformer Station Equipment - Operating Labour	4820	-	
Transformer Station Equipment - Operating Supplies an	4825	-	
Overhead Line Expenses	4830	-	
Underground Line Expenses	4835	-	
Transmission of Electricity by Others	4840	-	
Miscellaneous Transmission Expense	4845	-	
Rents	4850	-	
Maintenance Supervision and Engineering	4905	-	
Maintenance of Transformer Station Buildings and Fixtu	4910	-	
Maintenance of Transformer Station Equipment	4916	-	
Maintenance of Towers, Poles and Fixtures	4930	-	
Maintenance of Overhead Conductors and Devices	4935	-	
Maintenance of Overhead Lines - Right of Way	4940	-	
Maintenance of Overhead Lines - Roads and Trails Repa	4945	-	
Maintenance of Overhead Lines - Snow Removal from R	4950	-	
Maintenance of Underground Lines	4960	-	
Maintenance of Miscellaneous Transmission Plant	4965	-	
Operation Supervision and Engineering	5005	622,027.98	**27**
Load Dispatching	5010	232,037.56	**27**
Station Buildings and Fixtures Expense	5012	645,367.09	**27**
Transformer Station Equipment - Operation Labour	5014	56,147.01	**27**
Transformer Station Equipment - Operation Supplies an	5015	12,279.49	**27**
Distribution Station Equipment - Operation Labour	5016	14,089.48	**27**
Distribution Station Equipment - Operation Supplies and	5017	5,731.94	**27**
Overhead Distribution Lines and Feeders - Operation La	5020	590,961.28	**27**
Overhead Distribution Lines and Feeders - Operation Su	5025	204,265.94	**27**
Overhead Subtransmission Feeders - Operation	5030	5,187.79	**27**
Overhead Distribution Transformers- Operation	5035	7.07	**27**
Underground Distribution Lines and Feeders - Operation	5040	156,680.69	**27**
Underground Distribution Lines and Feeders - Operation	5045	22,823.74	**27**
Underground Subtransmission Feeders - Operation	5050	4,021.97	**27**
Underground Distribution Transformers - Operation	5055	15,657.41	**27**
Street Lighting and Signal System Expense	5060	-	**27**
Meter Expense	5065	354,831.34	**27**
Customer Premises - Operation Labour	5070	139,492.26	**27**
Customer Premises - Materials and Expenses	5075	56,305.91	**27**
Miscellaneous Distribution Expense	5085	470,319.60	**27**
Underground Distribution Lines and Feeders - Rental Pa	5090	61.55	**27**
Overhead Distribution Lines and Feeders - Rental Paid	5095	8,339.63	**27**
Other Rent	5096	104,334.61	**27**
Maintenance Supervision and Engineering	5105	-	**27**
Maintenance of Buildings and Fixtures - Distribution Sta	5110	281,749.92	**27**
Maintenance of Transformer Station Equipment	5112	27,628.09	**27**
Maintenance of Distribution Station Equipment	5114	36,394.68	**27**
Maintenance of Poles, Towers and Fixtures	5120	35,739.38	**27**
Maintenance of Overhead Conductors and Devices	5125	581,434.54	**27**
Maintenance of Overhead Conductors	5126	-	**27**
Maintenance of Overhead Services	5130	42,873.38	**27**
Overhead Distribution Lines and Feeders - Right of Way	5135	711,935.71	**27**
Maintenance of Underground Conduit	5145	83,892.88	**27**
Maintenance of Underground Conductors and Devices	5150	203,513.80	**27**
Maintenance of Underground Services	5155	73,080.32	**27**
Maintenance of Line Transformers	5160	71,121.48	**27**
Maintenance of Street Lighting and Signal Systems	5165	-	**27**
Sentinel Lights - Labour	5170	-	**27**
Sentinel Lights - Materials and Expenses	5172	-	**27**
Maintenance of Meters	5175	57,154.31	**27**
Customer Installations Expenses- Leased Property	5178	-	
Water Heater Rentals - Labour	5185	-	
Water Heater Rentals - Materials and Expenses	5186	-	
Water Heater Controls - Labour	5190	-	
Water Heater Controls - Materials and Expenses	5192	-	
Maintenance of Other Installations on Customer Premis	5195	-	
Purchase of Transmission and System Services	5205	-	
Transmission Charges	5210	-	
Transmission Charges Recovered	5215	-	
Supervision	5305	32,206.12	**29**
Meter Reading Expense	5310	350,588.88	**29**
Customer Billing	5315	468,565.50	**29**
Collecting	5320	341,960.51	**29**
Collecting- Cash Over and Short	5325	-	
Collection Charges	5330	-	
Bad Debt Expense	5335	378,851.89	**29**
Miscellaneous Customer Accounts Expenses	5340	-	
Supervision	5405	56,375.85	**31**

Community Relations - Sundry	5410	542,092.33	31
Energy Conservation	5415	-	
Community Safety Program	5420	28,189.29	31
Miscellaneous Customer Service and Informational Expe	5425	-	
Supervision	5505	-	
Demonstrating and Selling Expense	5510	-	
Advertising Expense	5515	-	
Miscellaneous Sales Expense	5520	-	
Executive Salaries and Expenses	5605	362,733.45	28
Management Salaries and Expenses	5610	530,930.17	28
General Administrative Salaries and Expenses	5615	371,544.05	28
Office Supplies and Expenses	5620	355,941.69	28
Administrative Expense Transferred/Credit	5625	-	
Outside Services Employed	5630	139,565.60	28
Property Insurance	5635	198,795.71	28
Injuries and Damages	5640	-	
Employee Pensions and Benefits	5645	-	
Franchise Requirements	5650	-	
Regulatory Expenses	5655	246,739.35	28
General Advertising Expenses	5660	-	
Miscellaneous General Expenses	5665	227,062.13	28
Rent	5670	-	
Maintenance of General Plant	5675	699,549.34	28
Electrical Safety Authority Fees	5680	-	
Special Purpose Charge Expense	5681	-	
Independent Market Operator Fees and Penalties	5685	-	
OM&A Contra	5695	-	
Amortization Expense - Property, Plant, and Equipment	5705	4,202,174.47	30
Amortization of Limited Term Electric Plant	5710	-	
Amortization of Intangibles and Other Electric Plant	5715	-	
Amortization of Electric Plant Acquisition Adjustments	5720	-	
Miscellaneous Amortization	5725	(112,432.93)	26
Amortization of Unrecovered Plant and Regulatory Stud	5730	-	
Amortization of Deferred Development Costs	5735	-	
Amortization of Deferred Charges	5740	-	
Interest on Long Term Debt	6005	1,468,529.97	33
Amortization of Debt Discount and Expense	6010	-	
Amortization of Premium on Debt/Credit	6015	-	
Amortization of Loss on Reacquired Debt	6020	-	
Amortization of Gain on Reacquired Debt--Credit	6025	-	
Interest on Debt to Associated Companies	6030	1,618,575.96	33
Other Interest Expense	6035	(29,042.59)	33
Allowance for Borrowed Funds Used During Constructio	6040	-	
Allowance For Other Funds Used During Construction	6042	-	
Interest Expense on Capital Lease Obligations	6045	-	
Taxes Other Than Income Taxes	6105	31,755.35	28
Income Taxes	6110	(44,000.00)	34
Provision for Future Income Taxes	6115	-	Ref K
Regulatory Deferral PILs Adjustment	6120	-	
Donations	6205	23,270.00	28
Life Insurance	6210	-	
Penalties	6215	348.62	28
Other Deductions	6225	-	
Extraordinary Income	6305	-	
Extraordinary Deductions	6310	-	
Income Taxes: Extraordinary Item	6315	-	
Discontinues Operations - Income/ Gains	6405	-	
Discontinued Operations - Deductions/ Losses	6410	-	
Income Taxes, Discontinued Operations	6415	-	
		0	

	3,899,721.00	1
	100,200.61	4
Ref A	3,999,921.61	

	627,361.00	10
	31,963.00	10
	(30,634.00)	21
	(59,051.00)	21
Ref B	569,639.00	

	390,000.00	11
	(1,471,000.00)	22
Ref C	(1,081,000.00)	

	(207,980.00)	16
	(65,513.16)	12
Ref D	(273,493.16)	

	(37,413,151.00)	18
	(1,211,084.00)	14
	(26,534,040.00)	18
Ref E	(65,158,275.00)	

	(32,865,176.37)	23
	(24,461,570.18)	36
Ref F	(57,326,746.55)	

	(3,906,962.16)	23
	844,433.42	36
Ref G	(3,062,528.74)	

	(4,087,091.52)	23
	20,198.34	36
Ref H	(4,066,893.18)	

	(15,495,940.47)	24
	(118,839.34)	26
Ref I	(15,614,779.81)	

	313,062.18	25
	(10,945.00)	36
Ref J	302,117.18	

	3,000.00	35
	(3,000.00)	37
Ref K	-	

APPENDIX 8

2013 PUC Inc. Annual Report

PUC Inc. ANNUAL REPORT 2013


PUC

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2013

HIGHLIGHTS

Financial	2013	2012
Gross Revenue	$89,888,107	$80,756,688
Net Income	$2,252,288	$1,768,870
Assets	$124,350,582	$112,793,148
Equity	$38,436,416	$36,755,628

Operations	2013	2012
Number of Customers (as of December 31)		
Residential	29,354	29,282
General Services	3,786	3,776

Electrical Requirements (GWh)	2013	2012
Residential	366.3	316.1
General Service	325.0	360.6
Losses, Unaccounted & Unbilled	39.3	36.6
Total Purchases	730.6	713.3
Peak System Demand (MW)	139.4	132.1

BOARD CHAIR and CEO MESSAGE

PUC Inc. continues to provide value and benefit to its sole shareholder, the City of Sault Ste. Marie. Once again, we provided $2.5 million in payments to the City. Since 2001 PUC Inc. has delivered $32 million to its shareholder.

PUC Distribution continues to focus efforts on improving reliability of supply. While 2013 outage performance indices deteriorated compared to 2012, we expect to realize continued improvement in the long run as we continue to implement various infrastructure renewal programs.

Looking to the future, PUC Distribution is working with several established partners to promote development of a smart grid in Sault Ste. Marie. Several projects were identified which we continue to actively pursue towards implementation.

We are especially proud of our achievement in controlling costs and providing value to our customers. In an environment where the increasing cost of power continues to outpace the normal cost of living, PUC Distribution's average residential bill is still the second lowest in the province. The fact that we keep only 19% of the total revenue we collect (81% goes to the province) is an important aspect of our operations that our customers need to know. This 19% is the revenue we have available to carry out all the work needed to operate and to reliably deliver power to our customers.

In response to the Minister of Energy's challenge early in 2013 to "bend the cost curve" for our customers, PUC Distribution undertook new collaborative efforts with a group of like-minded utilities, both in northern and southern parts of the province. Our collaboration with the CustomerFirst group is expected to provide cost efficiencies that will ultimately benefit our customers.

In 2013 our Shareholder Agreement was revised to include the requirement that we hold public board meetings. We would like to thank all members of the board and the executive team for their efforts in complying with this new requirement and for their support throughout the year.



L.A. Guerriero
Chair, PUC Inc.



Dominic Parrella
President & CEO, PUC Inc.





OUR BUSINESS

PUC Inc.

PUC Inc. is wholly owned by the Corporation of the City of Sault Ste. Marie. It has one active subsidiary, PUC Distribution Inc. and one inactive subsidiary, PUC Telecom Inc. (all assets of PUC Telecom were sold to Ontera, effective October 31, 2011). PUC Inc. is a registered company under the Ontario Business Corporations Act.

PUC Telecom

Effective October 31, 2011 the assets of PUC Telecom Inc. were sold to Ontera, its joint venture partner for the prior 10 years. The sale included approximately 120 km of fibre optic cable with varying numbers of fibre strands over specific distances, telecommunications equipment and customer service contacts. Certain fibre strands were reserved for the exclusive use of PUC affiliated companies.

Under the terms of the sale, PUC Telecom agreed to complete a number of commitments by October 31, 2013. All agreed-to commitments were met by the due date.

PUC Distribution Inc.

PUC Distribution Inc. distributes electricity to the majority of residences and businesses within the boundaries of the City of Sault Ste. Marie as well as parts of Prince and Dennis Townships and the Batchawana First Nation Reserve. The utility has 33,140 residential, commercial and small industrial customers, a total of 741 kilometers of conductor and 15 distribution stations. The distribution system is connected to the provincial transmission grid through two 115 kV transformer substations and 16 kilometers of 115 kV transmission lines owned by PUC Distribution Inc.

PUC Distribution is a regulated utility and must comply with requirements set by the Ontario Energy Board (OEB) with respect to conditions of service. Rates set for the distribution of electricity are approved by the OEB. As a participant in the electricity market PUC Distribution must comply with the rules of the Independent Electricity System Operator. The company must also adhere to all regulations established under the Ontario Electricity Act, 1998.

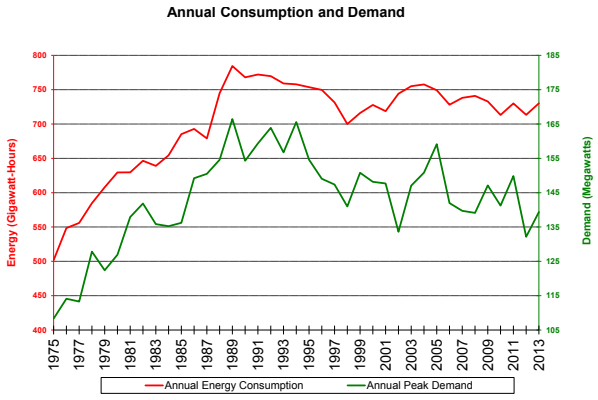
BUSINESS of PUC DISTRIBUTION INC.

System Loading

For 2013, the total amount of energy consumed by PUC Distribution's network was 730 GWh compared to 713 GWh for 2012. Electricity sales to customers for 2013 were up 2.4% from 2012. System peak demand for the year was 139.4 MW which occurred in December. The 2012 peak demand was 132.2 MW which occurred in January.

Figure 1 identifies total annual energy consumption and peak demand on the distribution system since 1975 (all quantities are adjusted to recognize embedded generator contributions).

Figure 1



Conservation and Demand Management (CDM)

The 2014 OEB mandated targets for PUC Distribution include an energy reduction target of 30.83 GWh and a summer demand reduction target of 5.58 MW. By year-end 2013, our projected accomplishment was 87% of the energy target and 43% of the demand target.

Throughout 2013 province-wide conservation and demand management programs continued to be offered by PUC Distribution Inc. and funded by the Ontario Power Authority "OPA". The OPA's "saveONenergy" campaign consists of consumer, commercial, institutional and industrial programs. The programs offer a wide range of tools, resources and incentives on energy conservation that can help reduce electricity costs and improve operating efficiencies.

During the course of the year, five consumer and three commercial and institutional initiatives were offered to customers. The consumer initiatives included the Fridge and Freezer Pickup, the Heating and Cooling Incentive, Energy Efficiency Coupons, Appliance Exchange Events and the Home Assistance Program. The commercial and institutional initiatives included Small Business Lighting, Retrofit Program and Audit Funding.
The Fridge and Freezer Pickup provides the opportunity for customers to have old appliances removed and recycled, in

an environmentally friendly manner, free of charge. Eligible appliances included refrigerators, freezers, window air conditioners and dehumidifiers. All primary appliances had to be at least 20 years old, in working condition and between 10 and 27 cubic feet in size. A total of 164 appliances were picked up and recycled in 2013.

The Heating and Cooling Incentive provided up to $650 in financial incentives towards the purchase of a new high efficiency electric furnace or central air conditioner. Over the course of the year, 529 residential customers participated in the program to take advantage of the financial incentive.

Energy efficiency coupons were available online throughout the year for residential customers to print and redeem at participating retailers. The coupons were also available on store shelves in the months of April and October. The coupons offered financial incentives at point of sale towards the purchase of energy efficient products. A total of about 3,014 coupons were redeemed by residential customers.

Appliance Exchange Events took place twice during the year. Customers receive incentives towards the purchase of new ENERGY STAR qualified appliances in exchange for their old appliances. The exchange events took place at participating retailers.

The Home Assistance Program provides residential retrofits which improve the energy efficiency of homes. These no charge retrofits are available to customers on fixed incomes who meet specific eligibility criteria. The Home Assistance Program provided assistance to 240 customers.

The Small Business Lighting initiative is available to small business customers who have a monthly peak demand less than or forecasted to be less than 50 kilowatts. All eligible customers are entitled to $1,500 in energy efficient lighting improvements with no financial contribution required by the customer. In 2013, 328 small business customers had energy efficient lighting upgrades completed.

The Retrofit Program provides substantial financial incentives to businesses for replacing existing equipment with high efficiency equipment and for installing new control systems that will improve the efficiency of operational procedures and processes. For many business owners, capital costs prove to be the primary barrier to investing and participating in a retrofit. The Retrofit Program's incentives tackle this barrier head on, making it possible for businesses to install and benefit from newer, more energy-efficient solutions. Throughout the year, 15 Retrofit projects were completed.

The Audit Funding initiative offers business customers incentives towards completing an energy audit. The energy audit assesses the potential for energy savings to be achieved through equipment replacement, operational practice changes, as well as other building systems projects. Two energy audits were incented over the course of 2013.

System Reliability

PUC Distribution is required by the OEB to track and report service reliability indices that measure system outage statistics for the electrical distribution system. These indices include the system average interruption duration index (SAIDI), the system average interruption frequency index (SAIFI) and the customer average interruption duration index (CAIDI), which is the ratio of SAIDI to SAIFI. All planned and unplanned outages lasting more than one minute must be reported. The indices are affected by factors such as customer density, the age and condition of the distribution system, susceptibility to lightning and other weather related impacts, the speed of response by crews and the scope of the supervisory and data acquisition (SCADA) systems deployed.

Reliability of electricity supply to PUC customers was negatively impacted by a number of significant weather related or equipment failure related outages in 2013. While overall reliability in 2013 appears to have deteriorated compared to 2012, our long term trend is expected to continue to improve on a year-over-year basis as we continue to replace deteriorated or failure prone equipment.

Outage statistics for the year 2013 deteriorated somewhat from 2012. Average duration and frequency of outages in 2013 increased over 2012 but were less than 2011. SAIDI was 2.48 for the year, compared to 1.65 for 2012. SAIFI was 2.67, compared to 2.17 for 2012. Figure 2 provides a summary of reliability indices since 2002.

Figure 2

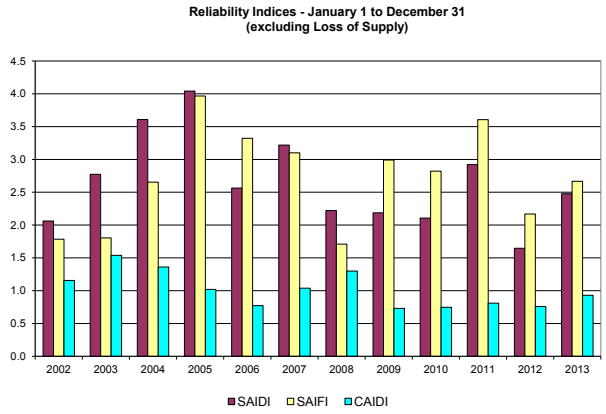


Figure 3 summarizes contributions by plant type to outage frequency and duration. There was one Loss of Supply event in 2013. Outages related to overhead plant provided the largest contribution to both outage duration and frequency, followed by transformer station equipment. Overhead plant accounted for 75% of all outage duration and 57% of all outage frequency. Transformer station equipment (breakers and switches) accounted for 13% of all outage duration and 12% of frequency.

Figure 3

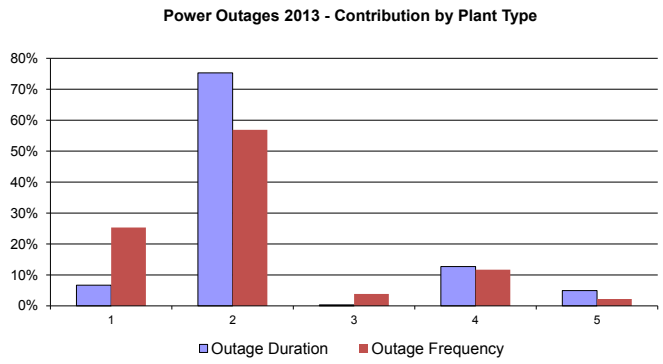


Figure 4 below summarizes the contributions by outage type for outages originating within PUC Distribution's system only (i.e. excluding the impacts of Loss of Supply). Equipment failure represented the largest impact for both duration and frequency of outages, accounting for 34% of SAIDI and 35% of SAIFI, followed closely by Trees on Lines at 32% of SAIDI and 26% of SAIFI.

Figure 4

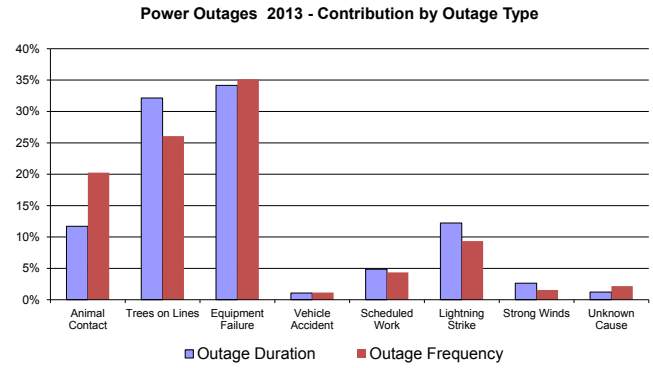


Figure 5 below summarizes the contribution of various categories of equipment failures to the annual system outage duration while Figure 6 summarizes contribution to annual outage frequency, for the period 2008 to 2013.

Figure 5

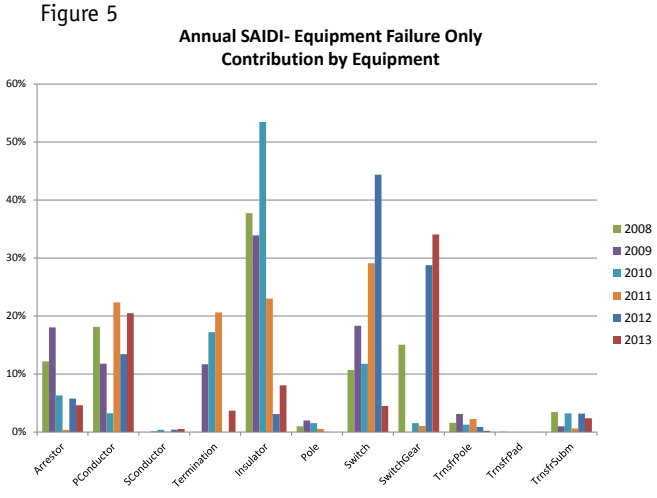
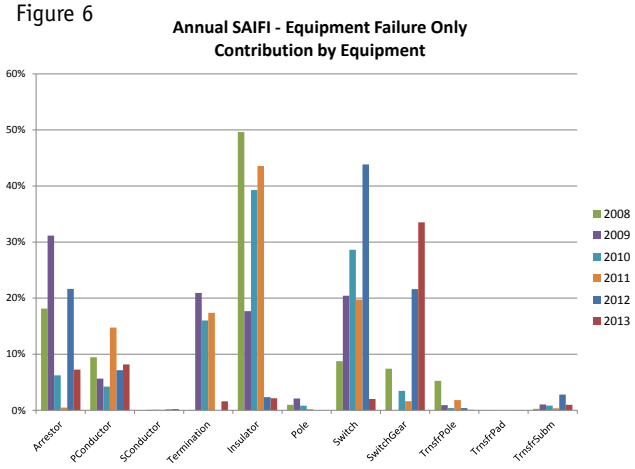


Figure 6



For 2013 failed switchgear (i.e. substation breakers and switches) was the largest contributor to system outages. Failed switchgear accounted for 34% of both total outage duration and frequency. The next highest contributor was PConductor (includes primary conductors and connectors) which accounted for 20% of duration and 8% of frequency.

Over the past several years, as can be seen from figures 4 and 5, failed insulators and switches have been significantly impactive on system outages. In response to this deteriorating reliability, we initiated a major commitment to replace approximately 3,000 failure prone insulators and 1,200 defective disconnect switches. All suspect insulators and switches will be replaced by end of 2014.

However, in 2012 and again in 2013, switchgear (i.e. substation breakers and switches) demonstrated increased impact on outages. Moving forward, we will devote significant effort to rebuilding and rehabilitating equipment at the two 115 kV transformer stations and the 15 distribution stations.

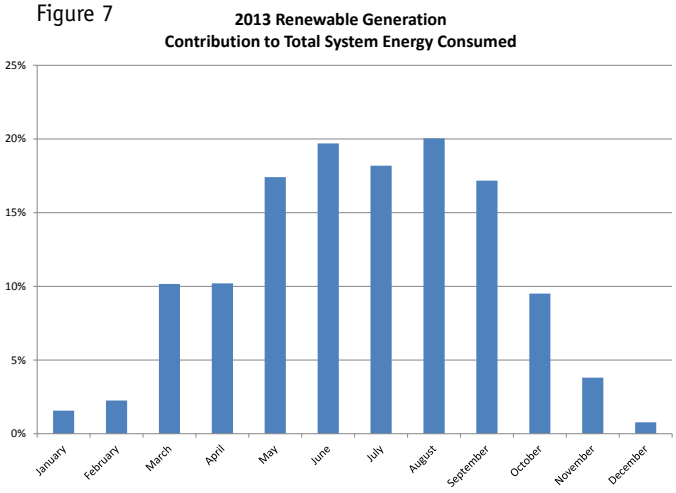
The age of the distribution system, including the distribution stations and transformer stations, makes it more vulnerable to outages. We have recognized the need to increase our level of infrastructure replacement and to improve system protection. In 2004 capital investment in renewal of the distribution system was $2.7 million. In 2013 the capital budget (related to the distribution system only) was $8.5 million. Over the next 10 years we expect to invest between $90 and $100 million of capital to renew the distribution system (including stations). In addition to infrastructure replacement, we will be making Smart Grid investments which will also help to reduce the extent and frequency of outages.

Renewable Generation Connections

Sault Ste. Marie currently has one of the highest saturations of renewable generation, in the form of photovoltaics, connected to a municipal distribution system in Ontario. Total solar energy generation on PUC's system is now approaching 62 megawatts. This is approximately equivalent to PUC's total load in off-peak daytime hours outside the summer air-conditioning period. As a result of this very unique situation, there is significant interest in conducting smart-grid/micro-grid research and development projects on the Sault Ste. Marie distribution system.

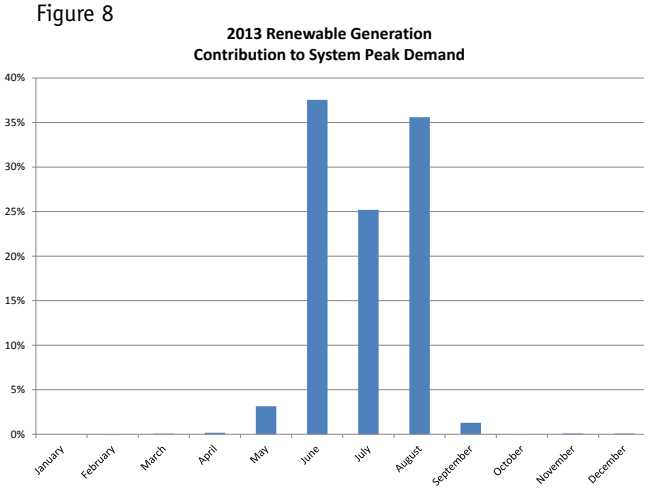
Solar generation connected to PUC Distribution's network supplied nearly 10% of the total energy consumed by PUC customers for the year 2013. Figure 7 identifies, on a monthly basis, the contribution produced by solar generation to total system energy consumed.

Figure 7



The greatest contribution from these generators towards system peak demand occurred in the months of June, July and August, ranging from a low of 25.2% of system demand in July to a high of 37.6% in June. Figure 8 identifies, on a monthly basis, the contribution from solar generation to monthly system peak demand.

Figure 8



Smart Grid Development

On May 14, 2009 the Ontario Legislature gave Royal Assent to Bill 150, the Green Energy and Green Economy Act, 2009 (the Act). The Act represents major legislation with far reaching impacts involving significant amendments to 15 other statutes.

The Act provides for a series of coordinated actions directed at enhancing economic activity and reducing our impact on the climate with two equally important thrusts:
1) making it easier to bring renewable energy projects to life, and
2) fostering a culture of conservation by assisting homeowners, government, schools and industries to transition to lower and more efficient energy use.

The Act established important new responsibilities for the Ontario Energy Board and other entities in achieving the objectives of conservation, promotion of renewable generation, and technological innovation through development of a smart grid.

Development of the "Smart Grid" is now a mandated requirement for all LDCs in Ontario. PUC Distribution is pursuing a number of Smart Grid projects in collaboration with local and international partners. We look forward to implementing leading edge technology in the near future that will improve reliability of supply and provide greater service to our customers.

CustomerFirst Inc. Collaboration for Cost Savings

Following the release of the Distribution Sector Review Panel's report in December of 2012, the Minister of Energy announced in March 2013 that the government would not implement one of the key recommendations of the report – that being, mandatory amalgamations of all LDCs across the province. In conjunction with that announcement, the Minister advised every LDC in Ontario that the government is… "focused on delivering ratepayer savings and on the need to "bend the cost curve" through more efficient service delivery."

Spurred by the Minister's comments, a group of eight like-minded LDCs, including PUC Distribution Inc., came together in mid-2013 to pursue collaborative efforts to demonstrate outcomes consistent with the Minister's directive. The CustomerFirst group collectively serves over 203,000 customers in municipal populations of nearly 571,000 citizens. The group is committed to increasing efficiency and customer service through collaboration, innovation and technology. Furthermore, the group is guided by respect for each member's shareholders and the communities which they serve.

The CustomerFirst members embrace a common theme: that on a cost basis, small-and mid-sized utilities are efficient and effective, and in many cases, are using the collaborative model to reduce costs for customers today. The members believe there are opportunities to expand scope and scale of the collaborative process to drive innovation, implement new technologies and to reduce costs for customers well before the 10 year timeframe identified by the Sector Review Panel.

The geographic diversity of CustomerFirst speaks volumes about the willingness of Ontario LDCs to collaborate for the betterment of both our customers and the industry. We expect this group will continue to grow as we develop services and capabilities that are of value to small and mid-sized utilities across the province.

FINANCIAL HIGHLIGHTS AND ANALYSIS

The financial highlights and analysis should be read in conjunction with the unaudited consolidated financial statements. The purpose of its inclusion in the annual report is to provide supplemental analysis and background material to enhance understanding of the company's business. Certain information included herein constitutes "forward-looking information". Forward-looking information means disclosure regarding possible events, conditions or results that are based on assumptions about future economic conditions and courses of action.

Certain information included herein may contain forward-looking information attributable to third parties. Although the company believes that it has a reasonable basis for the forward-looking information, such information is subject to a number of risks and uncertainties that may cause actual events, conditions or results to differ materially from those contemplated by the forward-looking information. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and weather. The company does not undertake any obligation to update publicly or to revise any of the forward-looking information included herein after the date hereof, whether as a result of new information, future events or otherwise.

Corporate Structure

PUC Inc. is wholly-owned by the Corporation of the City of Sault Ste. Marie and is a holding company which wholly-owns PUC Distribution Inc. and until December 31, 2013 wholly-owned PUC Telecom Inc.

PUC Distribution Inc. is a provincially regulated electric distribution company which is responsible for delivering electricity to residents of Sault Ste. Marie and specific surrounding areas, within its licensed service territory.

PUC Telecom Inc. had provided telecommunication services through a fibre optic ring within Sault Ste. Marie. However its operating assets were sold as of October 31, 2011. PUC Telecom was amalgamated with PUC Inc. as of January 1, 2014.

Net Income

The consolidated net income for the year ended December 31, 2013 was $2,252,288 compared to $1,768,870 for the year ended December 31, 2012. Earnings before taxes were consistent with 2012, however payments in lieu of income taxes were $497,752 lower than 2012.

Cash & Receivable from PUC Services Inc.

Cash and cash held by PUC Services Inc. on behalf of PUC Inc. fell in 2013 as a result of a portion of the new integrated facility (i.e. building) being financed through working capital and a decrease in regulatory liabilities.

Accounts Receivable

Increased energy prices, the timing of billing cycles and increased energy usage in November and December over prior year resulted in an increase in accounts receivable at December 31, 2013.

Notes Receivable

The note receivable from PUC Services Inc. remained unchanged in 2012.

Net Fixed Assets

The large increase in fixed assets was due to the completion of the construction of the new integrated facility which commenced in late 2011.

Net Regulatory Liabilities

PUC Distribution is required to bill and collect from customers on behalf of third parties, charges for energy, transmission and certain other provincial fees. Regulatory liabilities result from collecting more from electricity customers than was remitted to the third parties due to timing issues. Through the Ontario Energy Board's rate setting process, a regulatory liability is refunded to customers in subsequent years. Refunds applied to customers' bills in 2013 lead to a reduction in the net regulatory liabilities.

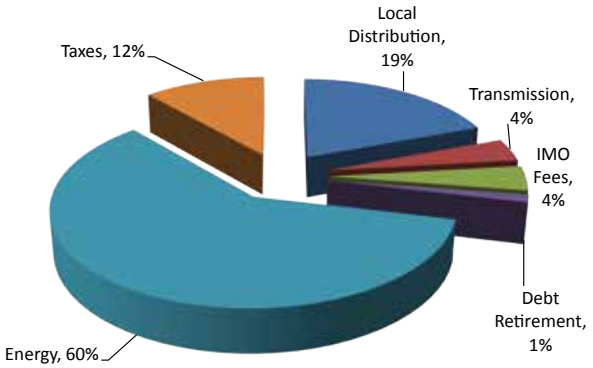
Notes Payable

The notes payable to the Corporation of the City of Sault Ste. Ste. Marie remained unchanged at $31.72 million. The construction loans of $5.0 million for the smart meter installation project and for the new integrated facility from Ontario Infrastructure Projects Corporation (OIPC) were locked into long term loans in 2013. The smart meter loan has a term of 15 years at 3.82% and an outstanding balance of $5.0 million at December 31, 2013. The new facility loan has a term of 25 years at 4.57% and an outstanding balance of $21.104 million at December 31, 2013.

Energy and Distribution Revenue

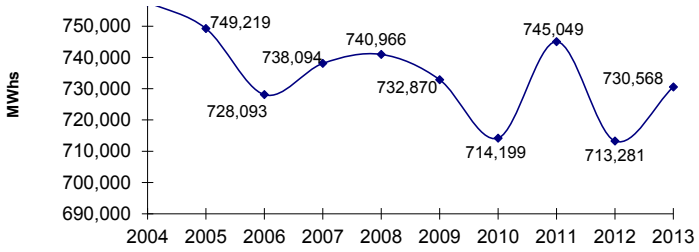
Approximately 80% of the energy revenue was collected from customers and flowed through at cost on behalf of other market participants. The remaining 20%, referred to as distribution revenue, is retained by the company to operate the local electric distribution system.

Allocation of funds collected on a typical 1,000 kWh residential bill as of July 1, 2013 is summarized in the following figure.



Distribution revenue was less in 2013 than 2012 as a result of the Ontario Energy Board's decision effective August 1, 2012 which instructed PUC Distribution Inc. to record smart meter costs and revenue that had previously been included in regulatory assets (net of regulatory liabilities) to be recorded in fixed assets, accumulated depreciation, distribution revenue, operating and administrative expenses and depreciation expense. Offsetting the reduction in revenue due to the smart meter decision was an increase in revenue from the approved cost of service rate increase as of July 1, 2013.

Energy withdrawn from the provincial grid increased in 2013 by 2% over 2012, as depicted in the figure below.



Other Revenue

Other revenue increased by $1,657,164. Reduction in third party construction work by PUC Distribution in 2013 was off-set by increased revenue for the rental of the new facility to PUC Services.

Distribution Expenses

Distribution expenses increased 4% over 2012.

General and Administrative Expenses

General and administrative expenses increased by 16% in 2013 as a consequence of increased facility costs from PUC Services.

Depreciation

The 2013 depreciation expense is under that of 2012. The smart meter regulatory entry to record depreciation on smart meters significantly increased depreciation expense in 2012.

Interest Expense

As in prior years, the Company paid $1.93 million in 2013 to its sole shareholder the Corporation of the City of Sault Ste. Marie. Since the company began operations in 2000, payments (dividends and interest) of $31.845 million were made to the Corporation of the City of Sault Ste. Marie.

Other interest increased by $476,954 in 2013. The construction loans of $5.0 million for the smart meter installation project and for the new integrated facility from Ontario Infrastructure Projects Corporation (OIPC) were locked into long term loans in 2013. The temporary construction loans that were at an interest rate of 1.95% were locked in for 15 and 25 years at 3.72% and 4.57%.

Gain on Sale of Assets

With the installation of smart meters, the disposition of the stranded conventional meters resulted in the $110,632 loss.

Provision for Payments in Lieu of Taxes (PILS)

An adjustment to the gain on the sale of PUC Telecom Inc. assets and reduced taxes payable by PUC Distribution (regulatory changes to depreciation compared to capital cost allowance) resulted in decreased PILs in 2013.

Liquidity and Capital Resources

The company's source of liquidity and capital resources has traditionally been generated from operations. The principle use of these funds is working capital requirements, maintenance, improvements, expansions to the electrical distribution system and other infrastructure, and to service the debt to the shareholder.

The company did not have third party debt until December 2009. In October 2009, a financing agreement with OIPC for up to $5.0 million to partially fund the mandated installation of smart meters was signed by PUC Distribution Inc. A construction advance of $3.5 million was received in December 2009 and a second construction advance of $1.5 million was received in December 2010. The loan was locked in for a period of 15 years commencing in 2013.

The company also locked in new integrated facility loan of $21.180 million with OIPC with a term of 25 years commencing in 2013.
In addition to the $1.93 million in interest payments made to the company's sole shareholder, a dividend payment of $610,080 was also made in 2013. Long-term debt remained at 60% of the company's capital structure in 2013.

PUC Inc.
Unaudited Consolidated Balance Sheet

	2013	2012
Assets		
Current Assets:		
Cash	$ 314,787	$ 538,117
Accounts Receivable	20,019,176	16,794,867
Inventory	1,675,485	1,274,852
Receivable from PUC Services Inc.	1,745,541	7,413,604
	23,754,989	26,021,440
Notes Receivable	8,310,000	8,310,000
Net Fixed Assets	81,467,997	76,136,708
Future Taxes	1,940,000	2,325,000
	$ 115,472,986	**$ 112,793,148**
Liabilities and Equity		
Accounts Payable	$ 13,743,264	$ 14,063,448
Net Regulatory Liabilities	5,469,267	7,783,142
Notes Payable	57,824,039	54,190,930
Equity:		
Common Shares	14,618,248	14,618,248
Special Shares	14,620,000	14,620,000
Retained Earnings	9,198,168	7,518,380
	38,436,416	36,755,628
	$ 115,472,986	**$ 112,793,148**

PUC Inc.
Unaudited Consolidated Income Statement

	2013	2012
Revenue		
Energy Revenue	$ 85,654,006	$ 78,179,751
Less Cost of Energy	68,769,142	60,573,316
Distribution Revenue	16,884,864	17,606,435
Other Revenue	4,234,101	2,576,937
	21,118,965	20,183,372
Expenses		
Distribution Expenses	6,100,113	5,859,541
General and Administrative Expenses	6,437,762	5,556,110
Depreciation	3,538,651	4,320,787
Interest Expense	2,692,443	2,215,489
	18,768,969	17,951,927
Earnings from Operations	2,349,996	2,231,445
Gain on Sale of Assets	(110,632)	22,253
Net Income Before Taxes	2,239,364	2,253,698
Provision for Payments in Lieu of Taxes	(12,924)	484,828
Net Income	**$ 2,252,288**	**$ 1,768,870**

Risk Factors

The company faces a number of risks in operating regulated and unregulated businesses.

Credit Risk

Credit risk is the risk that a party will fail to discharge its obligations and cause a financial loss to the company. Under the market rules introduced on May 1, 2002, the company is required to bill and collect electricity related charges on behalf of the majority of all market participants and remit the charges to the other market participants whether they are ultimately collected or not. The company's revenue is earned from a broad base of customers and it does not earn a significant amount of revenue from any single customer.

Credit risk is also mitigated through the use of letters of credit and cash deposits as permitted according to the Distribution System Code as revised by the OEB in 2004. The company does not provide significant electric service to the major industries in the municipality; however, financial difficulties at these companies could adversely affect the entire community and thus the distribution utility.

Weather Risk

Weather plays an important role in the operations of the distribution utility in two major areas. Severe weather conditions increase the likelihood of customer outages that affect operating costs and revenues. This risk is managed through such programs as the annual tree-trimming program, infrared surveys of plant and equipment, and by maintaining an adequate inventory of replacement parts.

The distribution rates allowed by the OEB are based on a fixed monthly charge and a variable volumetric charge. Differences from normal weather patterns could affect customer consumption and therefore variable distribution revenue in both a positive or negative way. The percentage of revenue collected from fixed charges and variable charges will be addressed by the OEB in the future.

Regulatory Risk

Regulatory risk is the risk that the Province and its regulator, the OEB, could establish a regulatory regime that imposes conditions that significantly reduces the rate of return that can be earned by electricity distributors. In addition, the ability to maintain the distribution system in the future depends on, among other factors, the OEB allowing recovery of the operating, maintenance and capital costs required in the future. The company monitors developments in the electricity industry and also relies on the Electricity Distributors Association to act on its behalf. Consultants with expertise in certain fields are utilized as required.

Environmental Risk

The company is subject to federal and provincial environmental regulation that is subject to change. Failure to comply with these regulations could result in orders to take specific actions or could subject the company to fines, penalties or third party claims. The company monitors developments in the environmental regulations and as required, utilizes consultants with the appropriate expertise.

Technology Risk

The use and complexity of the company's electronic infrastructure continues to increase and its reliability and security are critical to all areas of operation. As part of the management service contract with PUC Services Inc., an information technology (IT) department oversees networks, voice over internet protocol communications, enterprise software, smart meter operation, systems security and other emerging IT issues. In addition, outside resources with expertise in specific areas are utilized as necessary.

Human Resource Risk

As part of the management service contract with PUC Inc., PUC Services Inc. provides the workforce necessary to operate PUC Distribution Inc. Labour disruptions can affect ongoing operations. Collective agreements with the union employees in PUC Services Inc. are in effect until April 30, 2018.

PUC Services Inc., like others in the utility services industry, faces a significant number of retirements within the next decade. The retirement of individuals in technical, trades and management positions will result in the loss of a large pool of expertise, therefore replacements are hired in advance of projected retirements to promote the transfer of knowledge.

Other Risks

The company maintains a level of insurance coverage deemed appropriate by management and for matters for which insurance coverage is available.

Regulatory Issues

The company carries regulatory assets and liabilities on its balance sheet. Regulatory assets represent costs that have been deferred because it is probable that they will be recovered from customers in future periods through the rate-making process. Regulatory liabilities represent future reduction in revenue associated with amounts that are expected to be refunded to customers through the rate-making process.

Satisfactory settlement of retail settlement variance assets and liabilities have been approved for disposition by the OEB in each of the rate years up to the variance balance as at December 31, 2012 which will be disposed of in distribution

rates over a twelve month period commencing May 1, 2014. A request for settlement of the regulatory balance at December 31, 2013 will form a part of the 2014 rate application as is the normal process.

The OEB established a multi-year electricity distribution rate setting plan (rate rebasing) for the years 2008 to 2010. Under the plan, LDCs had rates adjusted based on projected expenditures. PUC Distribution was approved to be in the first group of LDCs to rebase rates in 2008 based on a "cost of service" rate application. On November 30, 2007, the company submitted a rate application based on the OEB Filing Requirements for Distribution Rate Applications. The company underwent a complete review of the level of the operating and capital expenditures required to maintain adequate customer service and improve system reliability and security. New approved rates based on the cost of service rate application were implemented July 1, 2008.

Rates, as determined in the "cost of service" rate proceeding, are adjusted by an inflationary factor and a productivity factor set by the OEB. PUC Distribution's rate increases for the portion of an electric bill which it retains to operate the local electricity system were 0.7% in 2009, 0.1% in 2010, 0.18% in 2011 and 0.88% in 2012 for a total increase of 1.86% over the four year period.

The company was scheduled to submit a "cost of service" rate application in 2011 for rates to be effective May 1, 2012, similar to that filed in 2007, based on projected expenditures. The company submitted a request and received approval from the OEB to delay filing its cost of service rate application for one year. In 2012, the company filed its cost of service rate application and received rate approval from the OEB effective as of July 1, 2013. The approved rates resulted in increased distribution revenue of 9.7% but decrease of approximately 2% to an average residential customer's overall monthly bill. The average annual distribution rate increase since the previous cost of service rate application is 2.3%.

In May 2009, the Green Energy and Green Economy Act, 2009 came into force. The Act allows LDCs to own renewable energy generation, addresses priority connection for renewable energy and smart grid implementation and instructed the OEB to set CDM targets that LDCs are to meet as a condition of their licences. The company's distribution licence has been amended requiring it to achieve 30.83 GWh of energies savings and 5.58 MW of demand savings from January 1, 2011 to December 31, 2014. The CDM program period has subsequently been extended to December 31, 2015. The company has signed an agreement with the OPA to deliver OPA funded CDM programs. It is expected that the company's mandated CDM targets will be reached through the OPA's programs.

In October of 2012 the OEB issued a report entitled Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach (RRFE). The report provides the direction that rate setting will follow commencing May of 2014. Three rate setting methods have been identified; a Fourth Generation Incentive Rate-setting method (building on the current Third Generation method); a Custom Incentive Rate-setting method (rates to be set on a five year forecast of revenue requirement and sales volumes) and an Annual Incentive Rate-setting Index method (adjustment of rates by a price cap index formula). Also required are five year capital plans and annual reporting of key performance outcomes. The company will assess the rate-setting methods and a method selected prior to the 2014 filing.

On April 13, 2012 the Province announced the creation of the Ontario Distribution Sector Review Panel to research, analyze, provide advice and make recommendations to the Minister of Energy regarding issues related to Ontario's electricity distribution sector and distribution models. The Panel was directed to consult with municipalities, Local Distribution Companies (LDCs), the Electricity Distributors Association (the EDA) and other energy experts. On December 12, 2012 the Panel released its report.

The Panel's report prompted significant outcry across the province over the key recommendation that consolidation of local distribution companies (LDCs) should be forced through legislation. Municipal Councils, as sole shareholders of LDCs, the Association of Municipalities of Ontario (AMO), the Electricity Distributors Association (the EDA) and LDC managers across the province unanimously condemned the concept of forced amalgamations. All agree that amalgamations should be encouraged, but that they should occur on a voluntary basis only, driven by the merits of the business case surrounding any proposals that may be considered.

On March 18, 2013 the new Minister of Energy, Bob Chiarelli, announced the government would not pursue forced amalgamations. Minister Chiarelli reaffirmed the government's commitment to deliver ratepayer savings and called upon all LDCs to come up with ways to … "bend the cost curve through more efficient service delivery." PUC continues to pursue efficiencies and productivity improvements, including active participation with both the EDA and other Northern Ontario utilities.

Accounting Policies

The audited financial statements of PUC Inc. have been prepared by management in accordance with Part V – Pre changeover accounting standards of the Canadian Institute of Chartered Accountants Handbook. The audited financial statements of PUC Distribution Inc. have been prepared by management in accordance with the Canadian Generally Accepted Accounting Principles for rate regulated entities. The company's management makes estimates and assumptions concerning reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the audited financial statements and amounts of revenues and expenses of the company for the period covered by the audited financial statements. The significant accounting policies of the companies are summarized in the notes to the audited financial statements.

Regulatory Assets

As a result of operating in a regulatory environment, regulatory assets and liabilities arise as part of the rate-making process. These assets and liabilities arise as a result of timing differences between costs being incurred or revenues being recognized versus when they are reflected in rates. Regulatory liabilities on the Balance Sheet at December 31, 2013 relate primarily to retail settlement variances and future taxes. The regulatory liabilities have been audited but a portion remains subject to approval by the OEB.

Employee Future Benefit Costs

As part of the management service contract with PUC Inc., PUC Services Inc. provides the workforce necessary to operate PUC Distribution Inc. PUC Services Inc. provides employee future benefits to current and retired employees including certain health and life insurance benefits. Future benefits for employees are recorded on an accrual basis. The accrual is based on costs determined by an independent actuary using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. The assumptions were determined by management with reference to recommendations of the actuary. The last actuarial valuation was completed for the year ended December 31, 2012.

PUC Services Inc. makes contributions on behalf of employees to the Ontario Municipal Employees Retirement System (OMERS), a multi-employer defined benefit pension plan. Pension fund premiums paid on behalf of employees are expensed when paid to OMERS. Employee future benefits are included in labour costs and charged to operations or capitalized as part of the cost of fixed assets.

Electricity Revenue and Unbilled Consumption

The company must use estimates for determining the amount of energy consumed and not yet billed due to the timing differences between billing dates and meter read dates, and the difference between billing dates and financial statement dates. Estimates are used in an attempt to match the cost of power expense, which is billed on a monthly basis, to electricity related revenue, which is based on meter reading periods that may straddle two months.

Future Tax Assets

As of October 1, 2001, the company became liable for payments in lieu of income and capital taxes in the same manner as if they were taxable under federal and provincial tax laws. As of the effective date of the regulations the assets of the company were deemed to be disposed of and reacquired at fair market value. The resulting tax bases of these assets were greater than their book value resulting in a future tax benefit associated with the additional deductions available for tax purposes. The future tax benefit is recognized on the balance sheet.

Future Accounting Standards

The company, as a publicly accountable enterprise, will be required to adopt International Financial Reporting Standards (IFRS) for annual reporting purposes for its fiscal year beginning January 1, 2015. An evaluation process is currently underway to determine the potential impact of the conversion to IFRS. The impacts on the consolidated financial statements are not reasonably determinable or estimable at this time.

Legal Issues

The company is subject to various litigation and claims with customers, suppliers, former employees and other parties as a normal course of operating a business. Currently, there are no significant legal matters pending.

Outlook

In late 2012 PUC Distribution submitted a "cost of service" rate application to the Ontario Energy Board (OEB). A "cost of service" application is an opportunity once every four years to adjust distribution rates to recover projected expenditures rather an annual adjustment based on less than inflation. PUC Distribution received approval to adjust its rates as of July 1, 2013. The application was successful in including the recovery of costs for the new building in the rate base and therefore in distribution revenue. However, the amount approved for operating, maintenance and administrative costs was significantly below the request submitted in the application. Therefore since the rates are set for 2014, 2015 and 2016 at an amount expected to increase by 1% to 1.5% per year, moving forward there will be a need to reprioritize operating, maintenance and administrative programs to fit within the spending envelope approved by the OEB.

The company continues to monitor its infrastructure program with the goal to improve outage frequency and duration and ensure a reliable system for the extended future. In addition to capital projects based on customer demand, reliability focused capital projects include: the pole replacement program, the voltage conversion program, phase one of the Substation 16 rebuild, transformer station refurbishments, the restricted wire replacement program, the ceramic disconnects and ceramic side-post insulator replacement programs. In addition, as part of under frequency load shedding as mandated by IESO, also to be addressed is the conversion of relays and expansion of the fibre network. The resources available to proceed with the projects to address system reliability will be depend on the volume of customer initiated work such as the Bell Aliant "Fibre To The Premise" (FTTP) project. Work will also continue on the implementation of energy conservation programs in order to reach the mandated energy reduction targets.

CORPORATE GOVERNANCE

During the past year the Board of Directors of PUC Inc. exercised all of the decision-making powers on behalf of the PUC Telecom Board The PUC Distribution Inc. Board is composed of three directors, two of which are independent, and makes decisions within the terms of reference established for that subsidiary.

The role of the PUC Inc. Board is to maximize shareholder value taking into account the legitimate interests of various stakeholders. Functions of the Board include the appointment of the President and Chief Executive Officer, appointment of Directors to subsidiary Boards, the provision of leadership in the development of a corporate strategic plan, approval of the corporate capital and operating budgets, review of annual financial statements, establishment of corporate policies, ensuring that policies are being followed and monitoring the performance of senior management.

The finance and audit committee of the PUC Inc. Board has the responsibility to ensure that the corporation has:

- implemented appropriate systems to identify, monitor and mitigate significant business risks;
- implemented appropriate systems of internal control to ensure compliance with legal, ethical and regulatory requirements, and that these systems are operating effectively;
- effectively carried out the internal audit function;
- reviewed and approved annual operating budgets;
- fairly presented annual audited financial statements in all material respects in accordance with generally accepted accounting principals.

Officers of the Corporation: (as of December 31, 2013)

Dominic Parrella, P. Eng.
President & CEO/Secretary

Terry Greco, CPA, CA
Vice President, Finance/ Treasurer

Claudio Stefano, P. Eng., MBA
Vice President, Operations & Engineering

Kevin Bell, P. Eng.
Vice President, Customer Services & Business Development

Board Members: (as of December 31, 2013)


Pat Mick


Mark Howson


Larry Guerriero


Doug Lawson


Cecilia Bruno


Bruno Barban


Frank Fata


Marchy Bruni


James Greco


Ella-Jean Richter
PUC Distribution Board


Jim Boniferro
PUC Distribution Board



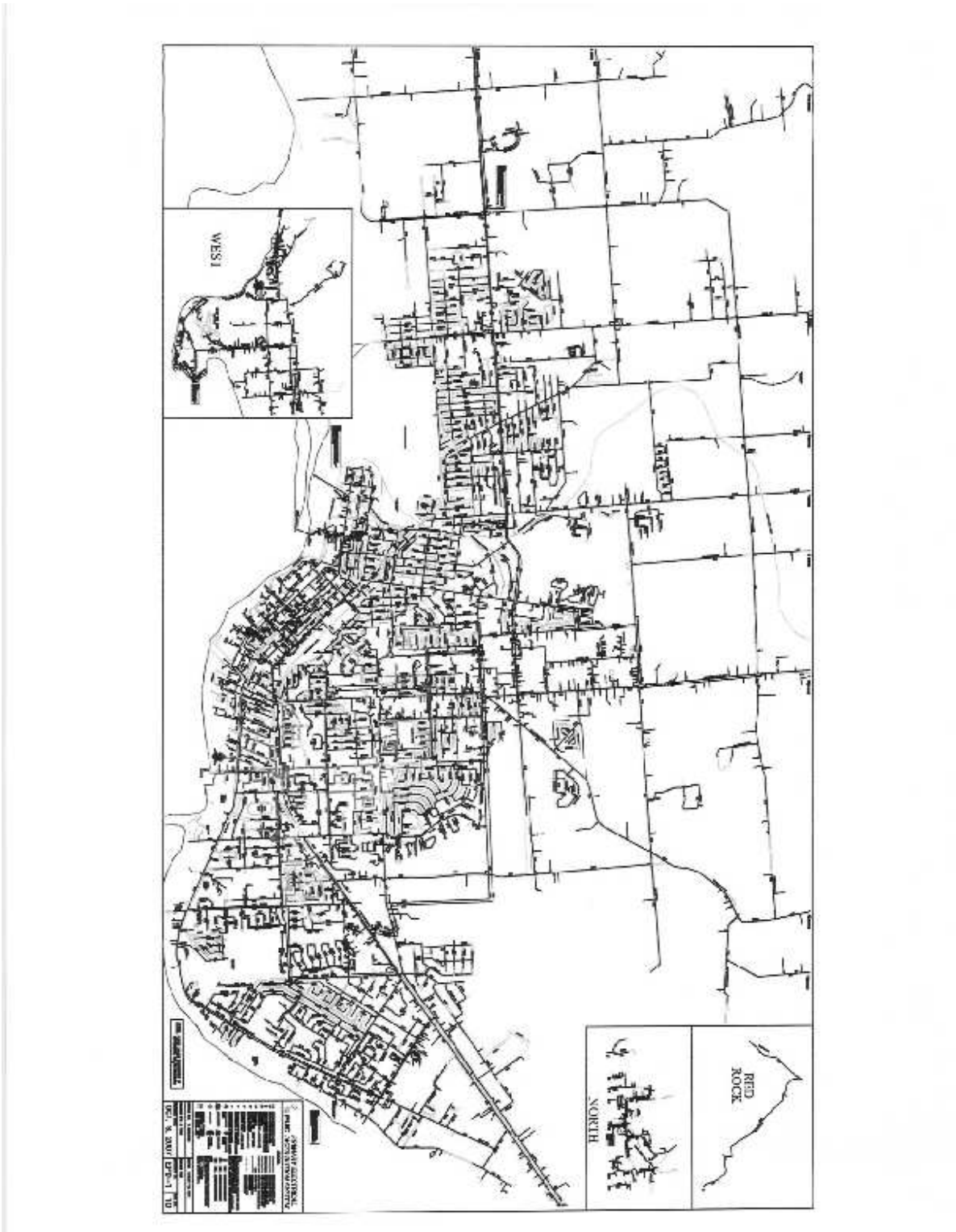
www.ssmpuc.com

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APPENDIX 9

Map of Distribution Service Territory and Service Areas

Map of Distribution Service Territory and Service Areas



APPENDIX 10

App. 2-AC Customer Engagement Activities Summary

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.
COS-SPECIFIC CUSTOMER ENGAGEMENT		
Customer Engagement Online Survey (in-house, 2017/18)	In 2018, PUC released a customer engagement survey that would provide customers with a new level of insight and transparency into operations, and infrastructure renewal projects. PUC's goal was to help customers stay informed, voice their opinions, create an open and honest dialogue about the state of the utility, the electrical distribution system, and plans for the future. Here are a list of priorities as per customer preference. 1. Customers believe PUC's first priority should be to keep rates as low as practical while maintaining good quality electrical service **= 58% said this was their first choice as PUC's # 1 priority** 2. Maintaining reliable electrical service (e.g. prevent/reduce power outages) **= 34% said this was their first choice as PUC's # 2 priority** 3. Helping customers reduce/manage consumption and by doing so reduce costs **= 34% said this was their first choice as PUC's # 3 priority** 4. Providing more information during power outages **= 41% said this was their first choice as PUC's # 4 priority**	PUC plans to host an information session about the application process for customers to better understand how the proposed rate increase will affect them, and capital investment projects in the DSP. **Low rates/maintain quality electrical service** Prolonged re-build of transformer stations Declined rate increase during 2015/16 Improved Reliability stats for SAIDI & SAIFI **Maintain reliable electrical service (prevent/reduce power outages):** Infrastructure renewal projects such as those in the DSP Voltage conversion projects (4kv to 12kv system) Improvements with vegetation management to reduce outages Focus on neighbourhoods with high equipment failure rates **Help customers reduce costs/manage consumption:** Conservation (CDM) information sessions, retail events, advertising Community partnership for energy-saving presentations Customer Connect - online portal that details consumption Customer Care phone calls include bill explanation with customers Business case studies (CDM-related projects) **Outage Notification:** Atlas Notification System (pro-active planned outage notification) Future plans to include text, email alerts Public Notices, website notifications, media releases **Community engagement/communication:** FTE providing information source for PUC operations, industry changes Customer consultations about infrastructure renewal in neighbourhoods Upgraded website to user-friendly Customer Connect - online account for accessibility Information sessions
SURVEYS		
Bi-annual Customer Satisfaction Survey - Residential and Commercial Customers (2015 & 2017)	In 2015 and 2017, customer satisfaction surveys were conducted by the third party organization, UtilityPulse, with both residential and commercial customers. **1. Reliability** **2.Better prices / lower rates** **3. Customer communication / online access** **4. Outage Notification**	PUC has made improvements such as, but not limited to, the following areas: **1. Reliability** Smart Meter/AMI data utilization for pro-active service delivery Customer Information System (CIS) & MCare (Electronic Service Orders) upgrade to improve services and response times for customers Improvements in vegetation management and infrastructure renewal VPR Partnership for assistance for those in need during emergencies **2. Better prices/lower costs** Expanding the tree trimming program to a 4-year cycle to cut costs Declining a rate increase in 2015/2016 based off the local economy and the status of Sault Ste. Marie's major employer Accountability training to ensure employees work efficiently **3. Customer Communication/Online Access** Customer Connect online platform to view detailed consumption Improvements in customer service; rebranding as Customer Care Customer Care training for management and staff Website upgrades, social media and local media communications Customer consultations for planned infrastructure renewal Energy conservation promoted via events, advertising, website, social media COS Customer Engagement Survey **4. Outage Notification** Upgrades to the phone system to handle more calls during outages Atlas Notification System for planned outages Website and media release information Upgraded phone system to handle more calls

Strategic Direction Plan Survey (2016)	In 2016, PUC started developing a new Corporate Strategic Plan to set direction and priorities for the utility over the coming years. **1. High cost of electricity/PUC advocating for customers** **2. Aging infrastructure** **3. Customer Sensitivity Training** **4. Information on lowering bills** **5. Moving services (online services made available)** **6. Incentives for upgrades (CDM, provincial initiatives)** **7. Accountability** **8. TOU Elimination**	**1. High cost of electricity/PUC advocating for customers** PUC advocated for customers during the February 2017 moratorium on winter disconnections Published media releases stating the breakdown of where the charges on the electricity bill go **2. Aging Infrastructure** Inclusion of renewal projects in the DSP Neighbourhood consultations with customers Information provided to customers about the distribution system **3. Customer Sensitivity Training** Management and employee participation in C.A.R.E. training Re-branded Customer Service to Customer Care **4. Information on lowering bills** Information sessions Customer Care trained on new CDM programs/initiatives available CDM promotions on website, social media, retail events, community events, Chamber of Commerce and B2B-related events **5. Moving Services** There are future opportunities to provide these services available online, rather than coming into the office to sign contracts **6. Incentives for upgrades (CDM programs/Gov't initiatives)** CDM presentations in the community, home shows (interactions) CDM advertising, social media, website Focus Groups to target electric heated-homes **7. Accountability** PUC participated in Accountability and Leadership training in 2017 to improve management and employee responsibility. An internal Business Improvement Committee was struck with a mandate to review internal business and process efficiencies. **8. TOU Elimination** Time-of-Use is a provincially mandated initiative. PUC continues to promote TOU, and understanding of the electricity bill Customer Care assists customers with consumption analysis and CDM promotes ways to conserve
Public Awareness of Electrical Safety Survey (2015 & 2016)	Ensuring the utility can provide safe electrical distribution Education and awareness about electrical safety, equipment, infrastructure Ensuring the utilities' operations are safe for workers and public Ontario One Call - Call Before You Dig Awareness	PUC scored the highest out of 36 LDC's with an awareness of 86% Ongoing Elementary School Safety program Caution and Chance Website Safety Section Purchase of Promotional "Dig Safe" for the Ontario One Call program Contribution to the production of electrical safety videos "Give 'Em a Brake" marketing for worker safety Participation in Science Festivals and Innovation Expos
INFORMATION SESSIONS		
Sault Ste. Marie Public Library (April 2017)	Lower Rates Better understanding of bill charges How to control energy usage Regulations like the Fair Hydro Act, Disconnections	Face-to-face interactive Information session at the library (advertised) PowerPoint presentation Conservation tips, upcoming/available programs Breaking down the costs in the electricity bill Understanding of disconnections, new industry regulations PUC received positive feedback about the event, stating the information provided was helpful and clarified concerns
Community Energy Learning Series (February 2017)	Lower Bills Understand bill charges How the electricity industry works Tips for Northern Ontario residents that deal with extreme cold Alternative energy What can they do to conserve?	Presentation at the Innovation Centre (partnership) How much the cost of electricity has risen in the last decade Bill breakdown Flow of electricity/how the industry operates Lighting tips, air sealing, energy efficient products/appliances, insulating, water heating, heating & cooling, windows Alternative energy like solar panels

MEETINGS		
Neighbourhood Project Meetings	Reliability Operational Transparency More involvement in decision-making	Engineering met with specific neighbourhoods and spoke with residents that would be affected by capital projects such as rear-lot pole replacements and underground cable replacements. Met with homeowners to discuss project objectives, logistics and impact to the property, if any.
FOCUS GROUPS		
HEAR (Home Energy Assessment and Retrofit)	Lower bills in the Winter High costs for electric heating Residential and Commercial customers with electric baseboards	CDM partnership presentation (local electricians/contractors) Pilot program offered residential home assessments Installation of programmable thermostats, low-flow shower heads, pipe wrap and block timers.
Customer First (Group of LDC's) Marketing Communications	Conservation information Understanding for residential and commercial customer base Knowledge of programs	CDM partnership with seven (7) other LDC's Improvements in marketing communications Residential and Commercial customers targeted Save on Energy branding Program availability knowledge with each customer base

COMMUNITY EVENT INTERACTIONS		
Retail Product Consultation Coupon Campaigns	Energy efficient products Conservation home upgrades	Partnerships with local hardware and home supply stores CDM product consultations in-store Promote energy efficient products, how it will help kWh usage Coupons to purchase products Conservation tips/tools available
Chamber of Commerce Business Breakfast	Business customers incentives Lower costs Increase energy efficiency	PowerPoint presentation on business incentives Partnered event with Algoma Power CDM provided awareness and program eligibility for businesses to minimize costs. Breakfast event and presentations for small business incentives, such as lighting, retro-fit programs and Save on Energy promotions. CDM would like to include a channel partner event and a business customer event in the future opportunities to meet with business customers
Chamber of Commerce Bridges to a Better Business	Small Business customer incentives Looking to minimize costs	CDM branded Save on Energy promotions and programs available Speaking opportunities with customers
Home/Trade Shows	Rate information Provincial rebates and regulations Face-to-face interactions with customers Ability to ask questions and have conversations about high costs Individual concerns	CDM promoted HEAR program, initiatives Explained Time-of-Use, Smart Meters, Online Services such as Customer Connect), capital projects, and sign-up customers for programs when eligible Customer Care & CDM reps on-site to answer questions personally
Festivals (RotaryFest and Bushplane Days)	Customers that have families may use more energy Safety awareness during an outage - downed power lines Time-of-Use, and what they can do to better manage usage	Explain Time-of-Use and consumption habits Electrical safety for children Provide information on program eligibility
SAFETY		
Caution and Chance Electrical Safety Awareness Program	Providing a safe electrical service to the community Ensuring children are safe and aware of any electrical hazards	Since 1995, this educational program has been implemented in elementary schools. Website Caution & Chance information section Social Media safety information posts
Marketing Campaigns "Give Our Workers a Brake" and the "Call Before you Dig"	Providing a safe electrical service Ensuring that safety is our top priority with workers/community	Marketing campaigns to promote safety Providing in-house underground utility location services to the community
CUSTOMER CARE		
Customer C.A.R.E. Training	Customers want to be treated fairly Customer-focus and valued Speak with a professional that can resolve their problems Strategic Direction Plan survey results revealed customers wanted employees to have "customer sensitivity" training	Entire organization underwent customer care training that included: How to ensure PUC is customer centered in everything we do Customer Loyalty Review of Customer Satisfaction survey (UtilityPulse-2017), what actual PUC customers have said they want/need Effective communication, active listening Why customers get upset, resolving customer concerns PUC has also re-branded its Customer Service to Customer Care to improve overall experience for each customer. Customer Care department will take the time to go through a person's bill with them. The representatives will connect customers with an Engineer or Planner to assist with questions related to neighbourhood projects. Being a local company, PUC is able to communicate in a more efficient manner as everyone
Internal Training	Consistent messaging from employees Knowledgeable, professional staff Information about electricity rates, industry changes, government rebates, and conservation program initiatives	Monthly staff meetings (include info about OEB backgrounders, winter disconnections, rate changes) CDM and Line Departments provide Customer Care, Billing and Metering departments with presentations review programs available Line department provides Customer Care department with presentations to help with terminology and understanding of the electrical distribution system
Customer Information System (CIS) and Mare (Electronic Service Orders)	Customer wait times for metering services Reliability with services offered Customer satisfaction Overall trust in PUC	PUC introduced the system upgrades to assist with inefficiencies with metering services, wrong meter readings, and customer billing issues. Upgraded from Harris to NorthStar system Real-time electronic communication with Meter department to improve services for customers Shorter wait times, quicker response Improved communication between customer, Customer Care, and the Meter Reading technicians to
Customer Connect	Monitoring consumption Customer control, ability to review bills Needed assistance with understanding bill breakdown How to manage usage, Time-of-Use Help with lowering bills	PUC introduced the Customer Connect option Online customer platform for easy access to information Ability to view current and historical data Allows for real-time access so the Customer Care department can analyze customer's bills, review spikes and provide information for better consumption habits based on the individual's usage As of November 2017, 8,596 PUC customers are signed up

Vulnerable Persons' Registry	Disabled customers or customers that experience any type of barrier Emergency services Reliability Ensuring safety is a priority for the community	PUC partnered with the Canadian Red Cross and the SSM Community Geomatics Centre for a service for vulnerable persons. Confidential database, links to PUC's GIS system Alerts Operations and Customer Care whenever an outage may impact a vulnerable person(s). Standard operating procedure includes cooperation with emergency services so PUC contacts first responders. Better communication during emergencies Ability to assist those in need, vulnerable/disabled
COMMUNITY SUPPORT		
Community Outreach	Corporate Social Responsibility Donations Event Sponsorships Investments back into the Community	**SSM Downtown Association** - banner installation & sponsorship **SSM Community Tree Lighting** - sponsorship **SSM Christmas Lighting Awards Program** - co-sponsor the event **The Lung Association Festival of Trees** - sponsor a CDM related tree, filled with energy efficient products **SSM Santa Claus Parade** - decorate a line truck, volunteer **Bon Soo Winter Festival** - Sponsorship **ARCH Hospice** - Employee Association Donation of over $7,500 **Christmas Safety Breakfast** - Donations to the SSM Food Bank **United Way** - $301, 222 fundraised/donated from 2008 - 2016 **LEAP Program** - Since 2012, donated over $130,000 to help low-income customers pay their electricity bills
COMMUNICATIONS		
Online Communications	Accessibility to information Knowledge of power outages Industry changes Conservation Program Availability Upcoming events, promotions Online services	**Website** - Upgraded to user-friendly, online Customer-focused portal "Customer Connect" for monitored consumption data, tree trimming services, "Call Before You Dig", infrastructure renewal projects, conservation tips, and program initiatives for homes and businesses **Social Media (Facebook, Twitter)** - Communications with different demographic audience and ability to post a variety of topics, more frequently
Public Notices	Accessibility to information Knowledge of power outages Reliability	PUC provides public notices to neighbourhoods in advance of planned projects and service modifications These notices are hand delivered to ensure customers receive them and are aware of any issues that may affect them or their routines
Public Relations / Media Relations	Accessibility to information Power Outage Notification Industry updates, Government rebates Conservation Program Availability Upcoming events, promotions Rate changes	PUC Communications department provides information to local online, print and radio media channels to ensure customers of all demographics receive the same information. Media interviews Press releases
Advertising	Accessibility to information	Public Service Announcements Time-of-Use ads Holiday lighting ads Conservation tips Tree trimming, worker safety
Bill Inserts	Improve rates Increase communication	PUC utilizes bill inserts to communicate regulatory information, new initiatives (such as the Atlas Outage Notification System), Government rebates, CDM programs and eligibility
Paperless Billing (E-Billing)	Reducing environmental impact Online access to bill (current and previous) Convenience	Online resource for customers 24/7 Access with Customer Connect platform (historical & current data) Paperless Billing Campaign is a future initiative to increase enrollment

APPENDIX 11

Customer Engagement Survey

Customer Engagement Overview

OVERVIEW

PUC Distribution Inc. (PUC) believes that customer engagement is the backbone of its community-driven operations. PUC recognizes that providing opportunities for customers to share their feedback will not only strengthen their relationship with them but also, improve the overall customer experience.

As a Local Distribution Company (LDC), PUC understands that its role in planning for the future of the electrical distribution system involves more than just measuring equipment service life. It requires including customers in the planning process to ensure that they have considered their needs and preferences when it comes to developing long-term plans. To that end, PUC is committed to growing and expanding on the success of its existing community service and customer engagement initiatives.

PUC has increased formal and informal community engagement activities with its customers over the last five (5) years. Those engagement opportunities identified a number of customer needs and preferences, along with room for improvements to be made. The areas identified that needed the most attention were improving customer communications, increasing customer consultations, and growing energy literacy in the community. Although many new ideas continue to be explored, we have successfully implemented a number of improvement initiatives over the past five years that have been directly related to customer feedback and expectations.

For the purposes of this summary, formal engagement is described as a direct, focused method to obtain detailed customer feedback pertaining to specific issues. For example, surveys, focus groups, and information sessions.

Informal engagement is described as an indirect method of engagement that supports two-way communications with customers. Customers are encouraged to share their opinions, feedback, and anecdotal experiences in an informal environment, such as a trade show, community festival, or retail consultation event.

CUSTOMER ENGAGEMENT (Formal)

The customer engagement program at PUC has gradually become more integrated into the operations of the company. It has evolved from a basic business-to-consumer relationship to a more strategic and informed partnership. This has been accomplished by the increased communications and outreach through surveys, media releases, and community speaking engagements, such as community information sessions. The formal customer engagement methodology is derived from the need to improve our community's overall energy literacy, especially pertaining to the electrical distribution system, its assets, and PUC's operations. We utilize the following to gain feedback from our customers, and to promote open discussion of customer issues, so that we may ensure we are continuously adapting to a customer-driven environment.

a. Customer Surveys

Additional efforts to inform, educate and engage with customers have been conducted through public surveys. The surveys gauge the understanding of the electricity bill, the electrical distribution system, PUC operations, well as the overall public perception and customer satisfaction.

i. Customer Engagement Survey (COS Application)

Purpose: This survey was developed to inform customers of the proposed rate increase associated with the 2018 Cost of Service application. It provided a short overview of PUC operations, cost drivers, bill breakdown, and a variety of capital projects needed to be completed. It allowed customers to comment, and open two-way communication between PUC and its customer base, in order to move forward with efficient customer engagement strategies.

Initiated By: PUC, third party consulting company

Participants: 2,004 (1,321 completed surveys)

Nature and Timing of Deliverables: PUC wanted to target 1,000 respondents regarding service reliability, COS application and most importantly, the proposed rate increase. The customer engagement survey was meant to open discussion about operations, and capital projects needed for system reliability. The survey results will be used as a benchmark to address customer concerns, and measure/track improvements.

DSP-related: Customers agreed that keeping rates as low as practical while maintaining good quality electrical service was the most important priority for PUC. The DSP was revised several times to ensure that the proposed rate increase was as low as possible, while taking the Asset Management Plan into consideration for necessary system renewal projects.

- The survey detailed the Operations, Maintenance and Administrative cost drivers, including new Regulatory Requirements, utility costs, bad debt, industry regulations, and inflationary increases which have all increased since 2012/2013. For that reason specifically, the DSP includes an additional staff member to assist with Rates and Regulatory needs. Currently, there is one person tasked with the R&R responsibilities.

- 48% of respondents agreed that they had a better understanding of the proposed rate increase to cover the OM&A costs, and another 12% that were interested in obtaining more information. The 5th project in the DSP complies with the OEB mandate requiring general service customers >50kW to be equipped with MIST revenue meters.
- Customers were informed of capital projects such as the overhead/underground system renewal, pole replacements, substation builds, and the voltage conversion replacement plan. One of the capital projects included in the DSP is the building of a new 12kV distribution station to replace two 4kV existing distribution stations that are currently in very poor condition and at the end of their useful service life. This will help reduce operating costs when the two 4kV stations are retired from service.

Future Considerations: PUC will expand on the DSP-related customer engagement through information sessions regarding projects listed in the DSP, including a Q&A discussion for customer input and concerns to be addressed. Furthermore, customer engagement related to the DSP framework and ongoing implementation will be conducted with timely, effective discussion.

Customer Engagement Survey - KEY FINDINGS

PUC, along with the assistance of a third party consultant, developed the Cost of Service, Customer Engagement survey to distribute to its customers. The survey provided PUC an opportunity to expand on its customer engagement, and provide customers with information on the proposed rate increase. The survey provided a short overview of PUC operations, cost drivers, the breakdown of a customer's electricity bill, and a variety of capital projects to be completed.

The survey had informational videos embedded within it. The videos included pertinent information related to the COS application, such as the cost drivers associated with operations, and planned capital projects. The survey was designed to provide two-way engagement between the PUC and its customer base. It allowed customers to provide feedback about existing services, and to share their thoughts about a proposed increase.

Some of the recurring themes in the survey analysis were:

- The cost of electricity
- Seniors on fixed incomes
- Dislike Smart Meter System (inefficient, costly)
- TOU discrimination (seniors, families, shift workers)
- High electric heating costs in Northern Ontario winters
- Government Assistance (should assist more with infrastructure renewal)
- PUC should be advocating/lobbying for customers with the Government
- Internal spending; cut costs before requesting an increase (provide evidence of doing so)
- Operation transparency (customers want more details and information on where money will be used)

The cost of electricity is a large concern for customers, and ensuring that good service is provided in the most cost-effective way needs to be a priority for PUC. The survey data indicates a large percentage of customers are on fixed incomes and are struggling to afford their electricity bills.

As a follow-up to the survey, and as an enhancement to the customer engagement element of PUC's operations, there are plans to host public information sessions. These will open discussion about the COS application, proposed increase, and most importantly address some of the customer comments received in the survey. PUC wants to ensure that their customers know they are listening to them, and care about their opinions. There will be specific sessions to ensure PUC engages larger business customers as well.

The following is a breakdown of the survey data, as well as the analysis of over 3,500 customer comments.

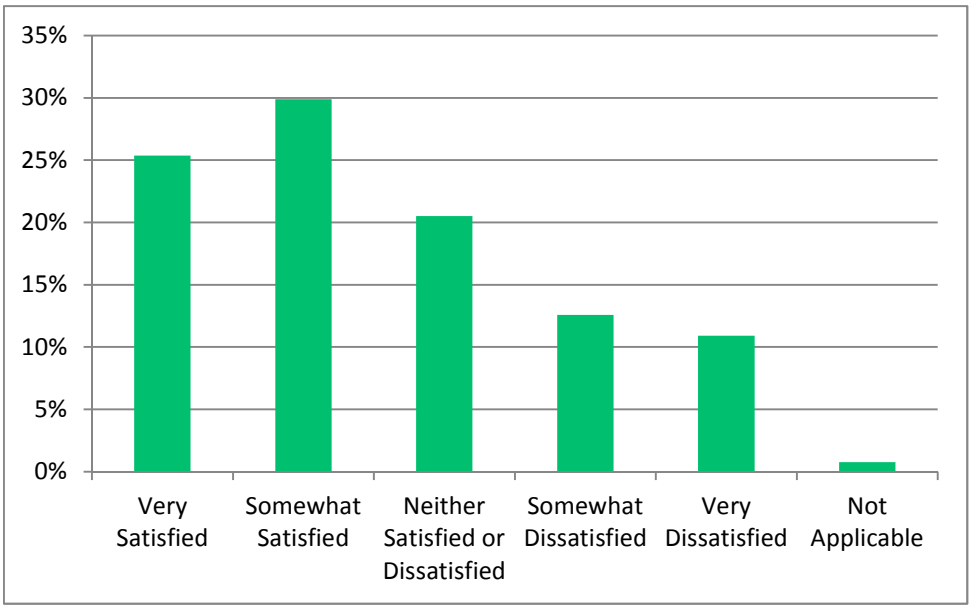
Customer Engagement Survey - DEMOGRAPHICS & SEGMENTATION

As of January 24, 2018, PUC Distribution's Customer Engagement survey had a combined total of 1,962 participants with 1,321 completed responses. The majority of respondents were aged 55-74, and based on the comments received in the survey, most are retired and living on a set income. The second largest contributors are ages 35-54. There was an equal amount of male and female participants.

The largest group of participants were homeowners at 85%, with the second largest being tenants at 12%. Unfortunately, the response from PUC business customers was low, so with that in mind, PUC plans on coordinating information sessions, specifically targeted to inform business customers on how the increase may affect them.

97% of survey participants were located in the City of Sault Ste. Marie, while another 3% of respondents were PUC customers in surrounding areas. PUC Distribution's customers are serviced by a multi-utility service provider, including electricity, water and the sewer charge for the City of Sault Ste. Marie, all included on a common bill. 85% of participants receive both electricity and water services. This is evident through the survey comments received, as many mention both electrical and water services.

Customer Engagement Survey - OVERALL SATISFACTION



Question 8

When asked about the overall customer satisfaction, results showed that 56% of respondents said that they were "very" or "somewhat satisfied" with the overall service(s) they received from PUC, while 24% were somewhat or very dissatisfied.

Out of the 342 comments received, participants elaborated on the factors they were unhappy with, or what they wanted more information about.

With the main concern identified in the comments as the 'High Cost of Electricity', PUC has worked hard to ensure that the proposed rate increase in the COS application, is as low as possible while still balancing infrastructure needs with customer affordability.

Additionally, many comments were received requesting more information about PUC's operations and transparency with internal spending. The Customer Engagement team will be delivering public information sessions to answer some of these and other questions that were raised in the survey comments.

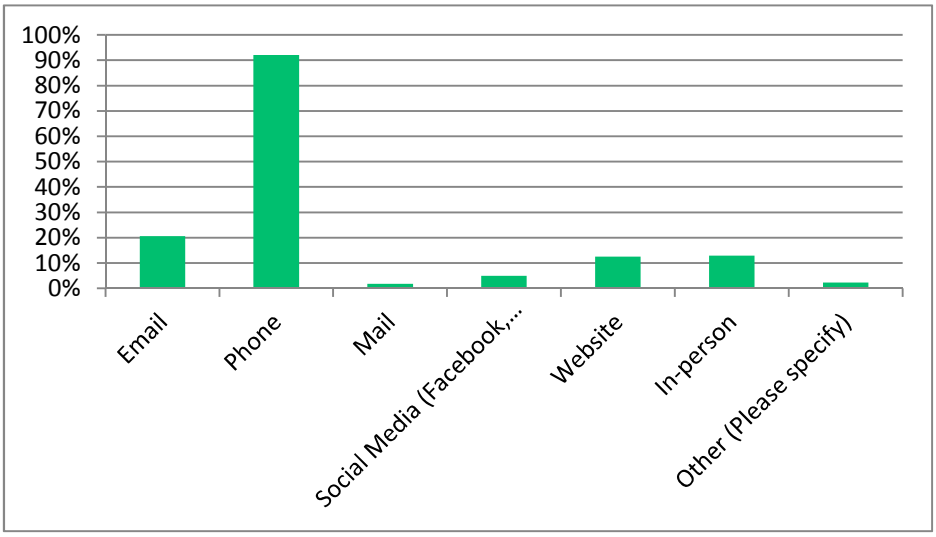
Customer Engagement Survey - PUC PRIORITIES

The OEB requires LDC's to understand customers' preferences so customers were asked to place PUC priorities in order of importance to them. The results support the importance of keeping costs as low as possible without sacrificing system reliability.

Out of the 1,321 respondents, these are the top three customer priorities:

1. 58% of respondents selected; "**Keep rates as low was practical while maintaining good quality electrical service**" as their number one priority. This supports the belief that customers want reliability, but want to ensure that it is done in a cost-effective way.
2. 34% of respondents selected; "**Maintaining reliable electrical service (e.g. prevent/reduce power outages)**" as their number two priority.
3. 34% of respondents selected; "**Helping customers reduce/manage consumption and by doing so reducing costs**" as their number three priority.

Customer Engagement Survey - COMMUNICATION

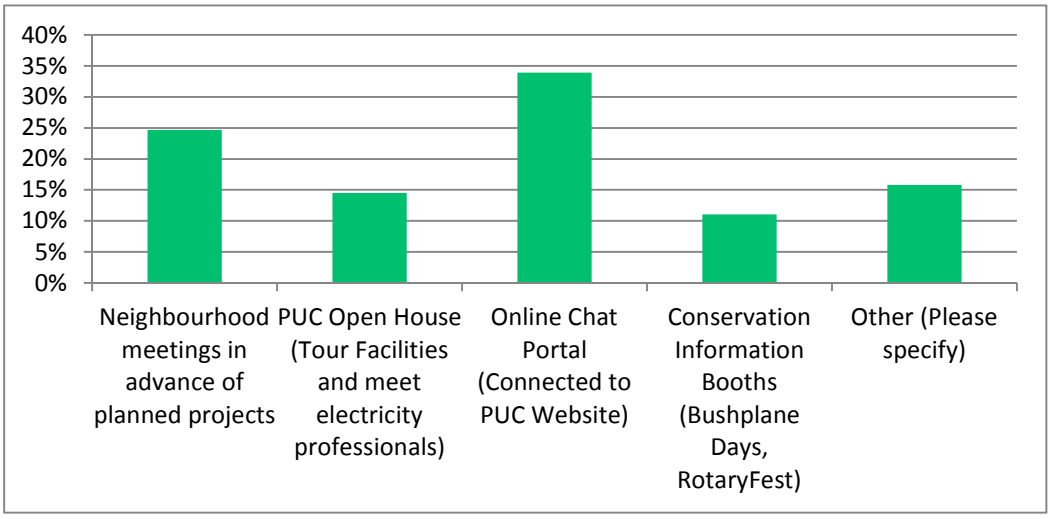


Question 14

Customers indicated overwhelmingly that their preferred method for contacting PUC for service issues was via the phone. However, some customers mentioned in the comments that they would appreciate the opportunity to speak with a PUC employee face-to-face, at their home.

In 2017, in an effort to improve customer service, PUC introduced a new stage in the planning process. Engineering technicians are now required to include customers whose property will be impacted by infrastructure renewal in the design phase of the project. Customer input will now be included directly into the design phase. The first example of this new engagement process occurred in 2017, with a number of submersible transformer being converted to a pad-mounted transformers in a neighborhood.

Improved customer communications is needed; this is evident through comments received and the overall perception customers have about PUC. However, while customers indicated that they would like PUC to improve communications and engagement, they do not want it at a significant cost to their bills.



Question 27

34% of customers responded in favour of an online chat portal as an improvement in communications, wanting to be connected to a live representative when they do have an issue. In response to this feedback, PUC is actively exploring options for integrating an online chat portal into its website by the end of 2018.

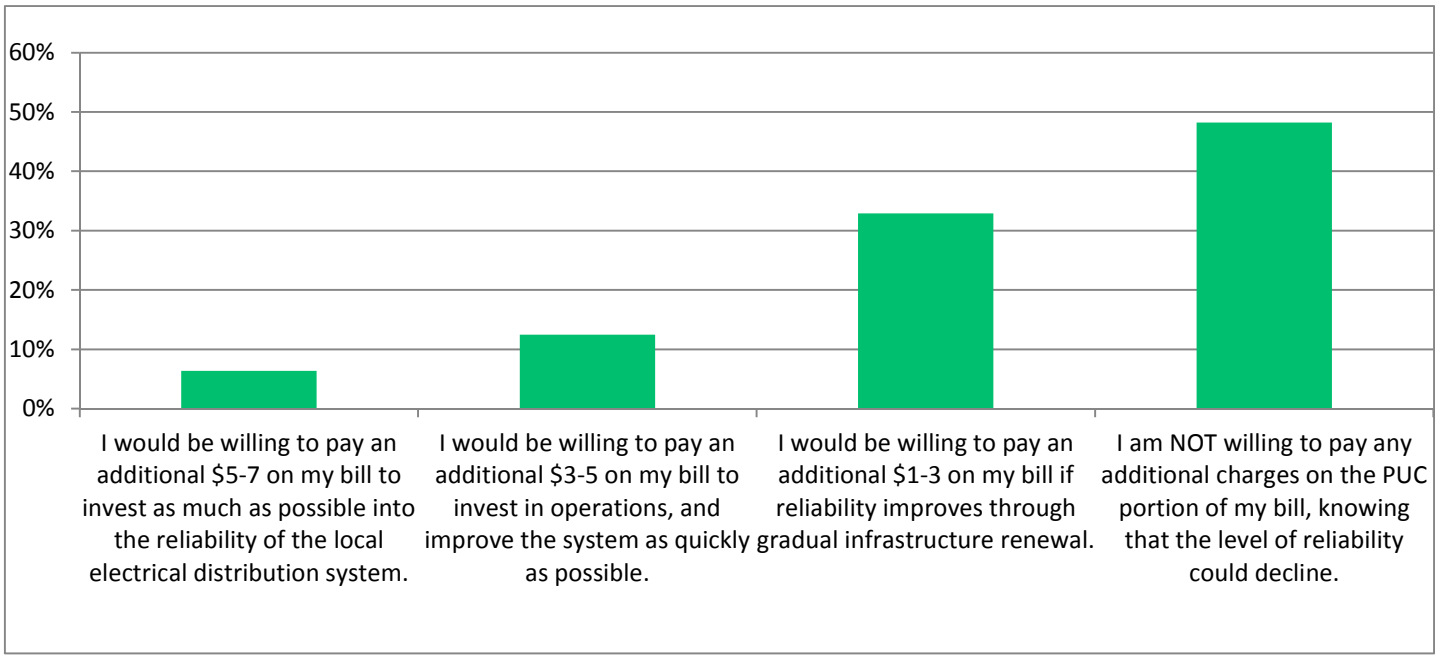
Customer Engagement Survey - OPERATIONS, MAINTENANCE & ADMINISTRATION

Participants were provided information on the cost drivers behind the PUC's proposed rate increase in the OM&A video. The goal was to provide customers with a better understanding of the reasons behind the proposed rate increase. After reviewing comments, it was evident that customers want more information, some questioning the validity of each cost increase, others not understanding regulations pertaining to the LDC. The survey results show that the majority of customers have a better understanding of the reasons behind the rate increase. However, there are still a large amount of customers that need more information, before they can support it.

This is another reason why PUC plans to host information sessions, release the survey results, address comments received, and provide clarification about operations. It will ensure customers have adequate knowledge of how PUC is regulated, what measures are in place to reduce spending, and how costs were reduced internally before requesting a rate increase.

Customer Engagement Survey - CAPITAL INVESTMENT PROJECTS

The participants were provided information on cost drivers related to infrastructure renewal, including voltage conversion, and sub-station rebuilds. After which, they were asked if they would be willing to pay any additional amount to assist with maintaining reliability, improving reliability, or not paying anything knowing that reliability of the system could decline.



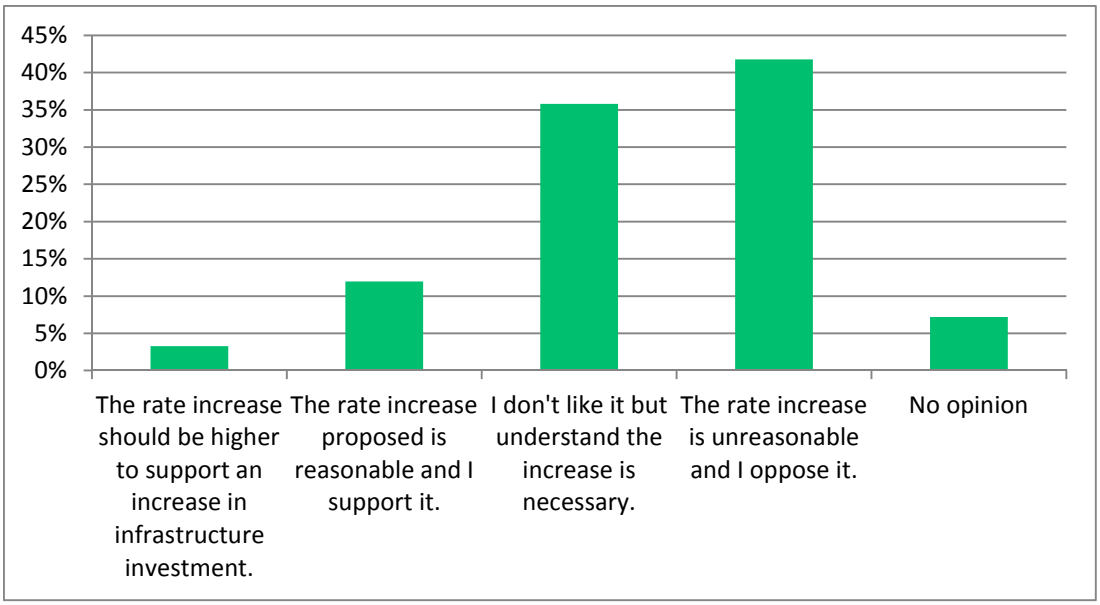
Question 22

The results represent an almost evenly divided group of customers 52% willing to pay something to improve reliability, and 48% unwilling to pay any additional amount for an increase in reliability.

While there were positive comments received from customers indicating that they understand the necessity of upgrading, along with maintaining equipment to ensure reliable service. There were also customers who stated that they need more information to support an increase of any kind; not that they oppose it.

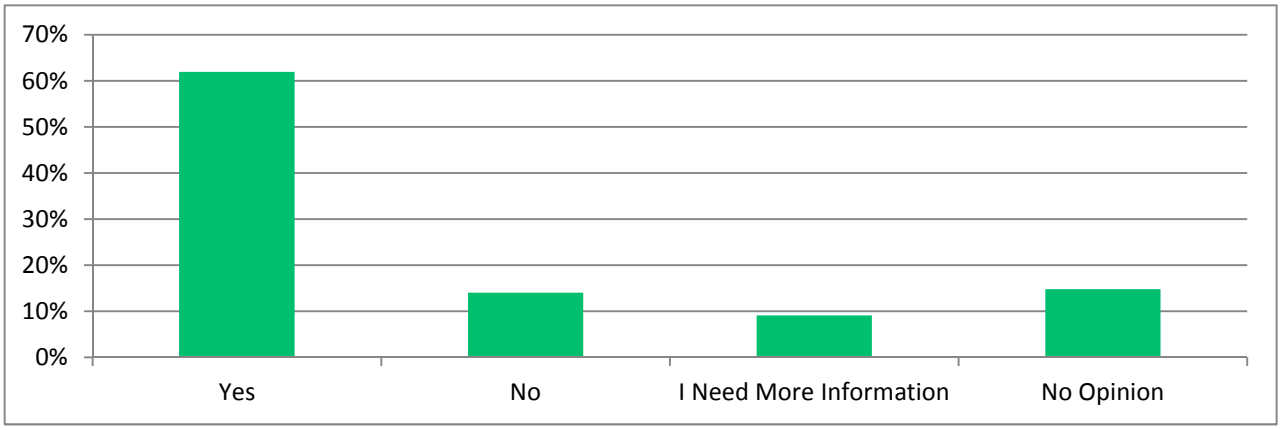
Customer Engagement Survey - PROPOSED INCREASE

When asked, ***Now that you're familiar with some of the planned projects, what do you think of the proposed rate increase to support infrastructure investment?*** A large segment of customers believe it to be unreasonable and do not support it. After reviewing comments, there were participants who once again mentioned needing clarification to make an informed decision to support or oppose the increase.



While a majority of customers either support the increase, or understand the necessity behind it – PUC recognizes that more needs to be done to engage with customers.

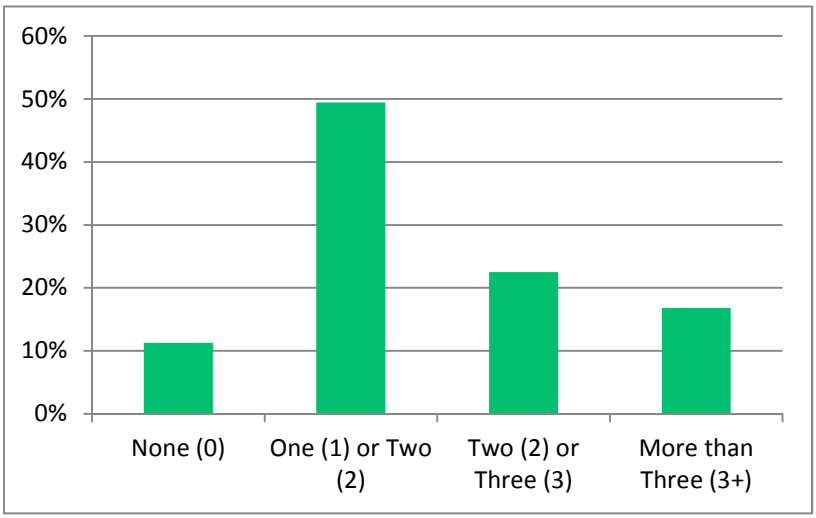
Most participants did state that they were provided with enough information in the survey to understand the reasons behind the proposed rate increase. This supports the previous question of customers understanding the rate increase is necessary, but not liking it or supporting it, based on the information provided to them. PUC will continue to provide information and address comments received in the survey to ensure customer concerns are addressed.



Question 24

Customer Engagement Survey - RELIABILITY

Customers chose "maintaining reliable electrical service" as the second priority for PUC. When customers were asked; ***In the Past Year, How Many Power Outages Have You Experienced?*** The results show that the majority of customers do not experience many outages.



Question 25

Customers rarely experience outages more than 3 times in a year. These statistics correspond with PUC's the reliability data for SAIDI and SAIFI. When asked; ***What was the longest power outage they had in the past year?*** 72% of participants indicated that they had only experienced short outages, up to 90 minutes.

When asked if they contacted PUC about the power outage, 71% of customers commented that they did not, stating that they trust the organization knowing that the problem will be reported, acknowledged, and fixed as soon as possible. 79% of customers agree that the reliability is "very good" or "good" when it comes to PUC response times for outages.

Reliability means more than maintaining quality electrical service; it also relates to PUC's responsiveness to customer needs and preferences. PUC has increased the amount of calls it can handle through software upgrades, provided an updated outage notification system, and improved services such as service orders for real-time metering.

Customer Engagement Survey - Exhibits

- Cost of Service Survey Master Script See: EXHIBIT 1
- Cost Of Service Survey Storyboard: EXHIBIT 2

ii. Customer Satisfaction Surveys (2015 and 2017)

Purpose: Gauge overall customer satisfaction, the utility's performance, public perception, and utilize as an engagement tool to collect quantitative data. Customers were also consulted about the willingness to pay an increase for expenses such as capital, and operational items.

Initiated By: PUC, through the Utility Pulse Division of Simul Corporation

Participants: **2017** - 1,553 Households (401 Completed Interviews) – Residential (85%) Commercial (15%)
2015 – 1,600 Households (403 Completed Interviews) – Residential (85%) Commercial (15%)

Nature and Timing of Deliverables: The survey allowed PUC to gain valuable insight from the results, including customer preferences about system reliability, infrastructure replacement, and PUC priorities. Unless otherwise stated, the results listed below are based on the most recent (2017) Electric Utility Customer Satisfaction Survey data.

DSP-related: 91% *(pg. 25 – 2017 UtilityPULSE CS Survey)* of ALL respondents with an opinion agree that PUC provides consistent, reliable electricity, and continues to meet customer expectations. Over the last 5 years, PUC has improved reliability for customers through voltage conversion projects, substation rebuilds, outage management system improvements and upgrades to the overhead/underground distribution system.

The amount of customers that believe a pro-active replacement of equipment to ensure reliable power (even though it may cost more) has declined by 8% from 72% in 2015 *(pg. 93 – 2015 UtilityPULSE CS Survey)* to 64% in 2017*(pg. 38 – 2017 UtilityPULSE CS Survey)*, based on **ALL** respondents. Although 89% of PUC customers *(pg. 16 – 2017 UtilityPULSE CS Survey)* agree that reliability is consistent with their expectations, 69% of all respondents *(pg. 41 – 2017 UtilityPULSE CS Survey)* (69% Residential and 70% Small Commercial) are willing to pay more to replace aging equipment to improve safety and reliability. As a result of customer input, this DSP focuses on equipment in poor or very poor condition, or near the end of its service life, in alignment with the Asset Management Plan.

The DSP includes a variety of projects that are driven in part by safety. For example, one of these projects is the rebuild of a substation (16), in very poor condition, and at the end of its service life. Due to the state of the existing station infrastructure, the switchgear is deemed to be unsafe to operate while energized and must be isolated and de-energized prior to operation. This results in isolation out on the 34.5kV sub-transmission lines, the path for one of two circuits feeding the local hospital.

Future Considerations: We have identified future opportunities to include more specific questions related to projects in the DSP. The biggest challenge is ensuring that the electrical engineering terms are communicated clearly enough for customers to understand equipment, processes and how the system works, which will be part of our customer education efforts.

Here are some of the results that compare 2015 and 2017 survey data (residential and businesses):

2015 *UtilityPULSE Customer Satisfaction Survey*	**2017** *UtilityPULSE Customer Satisfaction Survey*	**Variance**
* 89% agree PUC provides consistent, reliable electricity (pg. 14)	* 91% agree PUC provides consistent, reliable electricity (pg. 25)	+2% increase in reliability
* 89% agree PUC quickly handles outages and restores power (pg. 14)	* 90% agree PUC quickly handles outages and restores power (pg. 25)	+1% increase in outage management
* 89% agree electricity safety is a top priority for employees and contractors (pg. 14)	* 91% agree PUC ensures electricity safety is a top priority (pg. 25)	+2% increase in safety as a top priority
** 45% indicated they had a blackout or outage problem in the last year (pg. 9)	** 32% indicated they had a blackout or outage problem in the last year (pg. 12)	-13% decrease in blackout or outage issues; coincides with outage management and less occurrences
* 81% agree PUC is "easy to do business with" (pg. 15)	* 85% agree PUC is "easy to do business with" (pg. 5)	+4% increase in ease of doing business
* 75% agree PUC is customer-focused and treats customers as if they're valued (pg. 15)	* 73% agree PUC is customer-focused and treats customers as if they're valued (pg. 5)	- 2% decrease in being customer focused and treat customers as if they're valued
* 50% agree that the cost of electricity is reasonable when compared to other utilities (pg. 15)	* 44% agree that the cost of electricity is reasonable when compared to other utilities (pg. 25)	-6% decrease One of the lowest LDC rates in Ontario; customer perception remains a challenge.
** 13% had a billing problem in the last year; with majority stating the amount owing was too high (pg. 8)	** 25% had a billing problem in the last year; with majority stating the amount owing was too high (pg. 13)	+12% increase Generally, our analysis suggests the "problem" is high cost rather than billing errors.

Based on* **ALL *respondents with an opinion*

***Based on* **ALL** *respondents*

Reliability

- 89% of **ALL** respondents agree PUC has a standard of reliability that meets their expectations *(pg. 16 – 2017 UtilityPULSE CS Survey)*
- 92% of **ALL** respondents agree that PUC is effective in responding to outages *(pg. 19 – 2017 UtilityPULSE CS Survey)*
- 94% of **ALL** respondents agree PUC restores power quickly *(pg. 19 – 2017 UtilityPULSE CS Survey)*
- 57% of **ALL** respondents with an opinion agree PUC provides good value for money *(pg. 25 – 2017 UtilityPULSE CS Survey)*

We have identified this as an opportunity to educate customers about operations and what is done with the amount that PUC retains on their bill. This is evident through CDM initiatives such as funded programs, in-store retail product consultations, and information sessions for understanding the electricity bill. It is our responsibility, in the position of trust and public interest that we communicate what PUC is doing to improve the electric system, ways we are trying to keep the rates at reasonable levels and improvements to expect with capital investments.

PUC is increasing customer engagement and improving the methodology used to do so, including an interactive customer survey that provides a detailed overview of operational and capital costs for customers to understand. Based on the results of our formal engagement, PUC has implemented several customer-driven changes which are as follows:

Better prices/lower rates

PUC customers are increasingly focused on their electricity costs, with emphasis on receiving better prices and lower rates. There has been a dramatic increase, from 36% of total respondents with suggestions in 2015 *(pg. 75 – 2017 UtilityPULSE CS Survey),* and now 67% of **ALL** respondents in 2017 *(pg. 46 – 2017 UtilityPULSE CS Survey)*. PUC does not believe our customers want to see us sacrificing their electrical distribution system's reliability and service levels for the lowest rate. PUC believes its obligation to the public is to provide a safe, reliable, and efficient service as well as meeting regulatory requirements as an LDC.

During 2015/2016 operations, PUC declined a potential rate increase, recognizing in part severe concerns on the state of the local economy. Our largest employer, a steel manufacturer experienced a time of financial hardship. Knowing that a vast majority of customers rely on income from the steel manufacturer, we understood that it was not a good time for the suggested rate increase, even though it was needed.

Most customers are unaware of the ageing of the electrical distribution system infrastructure, operational costs, and asset renewal. With that in mind, we have introduced engagement opportunities to provide energy literacy. The price of electricity has also risen provincially in the last few years, and customers are feeling the effects on their bills. Although the Provincial 25% cost reduction has been of great assistance to residential customers, small business has not seen the same reduction and have been hit hard by local economic conditions.

Although a large percentage of our assets are part of an aging electrical distribution system, we have held off on capital investments for large-scale infrastructure such as the transformer stations, based on customer concern for increasing costs. PUC has developed its DSP to include asset renewal at a steady pace, rather than a significant increase that would affect the customers more advertently. Especially being in the North, where heating costs can be highly impacted during the winter months, and the local economy is still reeling from the effect of the steel industry.

Customer Communication = Online Access *(2017 UtilityPULSE CS Survey Results)*

- 83% of total respondents access the internet for information; 71 % use online banking *(pg. 27)*
- 72% of **ALL** respondents agree PUC effectively provides information about the outage *(pg. 19)*
- 75% of **ALL** respondents agree PUC provides information to help customers reduce their costs *(pg. 47)*
- 69% of **ALL** respondents agree PUC is using media channels for updates *(pg. 19)*
- 58 % of **ALL** respondents agree researching information about energy conservation *(pg. 28)*
- 53% of **ALL** respondents agree that it was important to review their bill online *(pg. 28)*
- 44% of **ALL** respondents agree that tools and calculators are important to help manage consumption *(pg. 28)*
- 34% of **ALL** respondents agree automated alerts to remind you of your bill date *(pg. 28)*

We have increased our online presence for power outage notification and conservation on our website and local media outlets. The introduction of the customer portal, Customer Connect, was implemented to aid customers in understanding usage, utilized as a tool to change consumption habits based off TOU data, and to ensure customers had the information to make choices about usage.

Trust

Overall, 85% of Secure and Favourable respondents are confident that PUC Distribution is using good judgment to prioritize investments *(pg. 37 – 2017 UtilityPULSE CS Survey Results)*

Willing to Pay For

In 2015, customers (*based on 90% of **ALL** respondents from the PUC), top **operational** items they were willing to pay more for *(pg. 96 – 2017 UtilityPULSE CS Survey Results)*

- 54% increased tree trimming
- 46% a proactive outage management system
- 46% educating customers and the public about electricity safety
- 45% educating customers about energy conservation

In 2017, customers (based off **ALL** respondents), top **operational** items they were willing to pay more for: *(pg. 44 – 2017 UtilityPULSE CS Survey Results)*

- 23% a proactive outage management system
- 23% educating customers about energy conservation
- 13% increased self-service options on the website

In 2017, customers (based off **ALL** respondents), top **capital** items they were willing to pay more for: *(pg. 41 - 2017 UtilityPULSE CS Survey Results*)

- 69% replacing aging equipment to improve safety and reliability
  - Of those who answered YES = Residential 69% / Small Commercial 70%
- 50% upgrading equipment to accommodate future growth in the community
  - Of those who answered YES = Residential 47% / Small Commercial 63%

Which of the following OPERATIONAL items would you be willing to pay more for?					
PUC Distribution	Yes	No	Not sure	Residential Yes	Small Commercial Yes
A proactive outage management system	23%	74%	3%	23%	27%
Increased self-service options on the website	13%	85%	2%	13%	12%
Educating customers about energy conservation	23%	76%	1%	23%	22%

(pg. 44 – PUC Distribution Inc. 2017 UtilityPULSE Customer Satisfaction Survey)

Which of the following CAPITAL items would you be willing to pay more for?					
PUC Distribution	Yes	No	Not sure	Residential Yes	Small Commercial Yes
Replacing aging equipment to improve safety and reliability	69%	29%	2%	69%	70%
Upgrading equipment to accommodate future growth in the community	50%	48%	2%	47%	63%
Adding automation and technology to reduce outage time	45%	52%	2%	43%	55%
Investing in technology to deal with cyber security issues	37%	58%	5%	37%	33%

(pg. 41 – PUC Distribution Inc. 2017 UtilityPULSE Customer Satisfaction Survey)

Strategy for replacing equipment

PUC Distribution	Residential	Small Commercial
Run-to-failure when there are limited customers affected ensures full-value is received from the equipment	21%	13%
Pro-active replacement, even though it may cost more, should ensure reliable power	63%	68%
Don't Know	16%	18%

(pg. 39 – PUC Distribution Inc. 2017 UtilityPULSE Customer Satisfaction Survey)

Strategy for replacing equipment

PUC Distribution	2017	2015
Run-to-failure when there are limited customers affected ensures full-value is received from the equipment	20%	19%
Pro-active replacement, even though it may cost more, should ensure reliable power	64%	72%
Don't Know	16%	10%

Base: total respondents

(pg. 38 – PUC Distribution Inc. 2017 UtilityPULSE Customer Satisfaction Survey)

iii. Strategic Direction Plan Survey (2016)

Purpose: PUC started the process of developing a new Corporate Strategic Plan to set direction and priorities for the utility over the coming years. Customers were asked their opinions on the organization's strategic direction, and what they believed were key challenges for the utility. PUC wanted to gain feedback to support the development of the strategic plan.

Initiated By: PUC, through Ironside Consulting Services Inc.

Participants: 194 Respondents (Customers and other Stakeholders)

Nature and Timing of Deliverables: The survey allowed PUC to gain valuable insight from the results, including input to align the utility's vision, values and PUC priorities.

DSP-related: 83% of survey participants agree that PUC's key challenges include rate increases, 67% agree aging electric infrastructure, and 55% state the uncertain local economy. 92% of customers are aware that PUC does not set the price of electricity, although 76% believe the cost for electricity is not reasonable.

65% of respondents determined that in order to meet these challenges, PUC must ensure that rates are kept fair and competitive. PUC elected to defer a rate increase in 2016 based on the state of the local economy.

52% of respondents believe that rate increases must be reasonable in order to address aging infrastructure. The DSP includes necessary system improvements that will occur gradually, and not at a substantial cost increase to PUC customers, due to their concerns about affordability. PUC has worked to balance the infrastructure and affordability drivers with a proposed rate increase that will affect the total average (using 750kWh) residential electricity bill, by less than $3.00/month.

Customers spoke about the importance of including Customer Service Sensitivity Training, which PUC implemented in 2017 as part of the entire organization's participation in C.A.R.E. Training. Customers wanted more information on bills, residential, commercial and industrial electricity rates in Ontario which PUC introduced at the Public Library information sessions, as well as the Innovation Centre presentations. Comments were received about the importance of affordability as well as money allocation going towards infrastructure improvements.

Customers mentioned online services for moving of service, rather than having to come into the office to initiate service change. They would like to see more incentive programs to get rid of older, inefficient appliances, and more conservation awareness to improve public education and customer outreach. There were also customers who spoke of accountability as an organization; striving to decrease spending internally with overtime, fleet vehicles, and purchasing. The PUC underwent Accountability and Leadership training in 2017 to improve management and employee responsibility. An internal Business Improvement Committee was struck with a mandate to review internal business and process efficiencies. Lastly, customers wanted to eliminate TOU based on discrimination with stay at home parents, large families, aged, ill and unemployed demographics.

iv. Public Awareness of Electrical Safety Survey (2015 and 2016)

Purpose: PUC Distribution participated in a public electrical safety awareness survey to provide a benchmark level concerning the public's electrical safety awareness and identify opportunities where additional education and outreach may be required.

Initiated By: PUC, through the Utility Pulse Division of Simul Corporation

Participants: A representative sample of PUC Distribution's service territory population was surveyed to gauge the public's awareness level of key electrical safety concepts related to distribution assets (the survey was based on a template provided by the Electrical Safety Authority).

Nature and Timing of Deliverables: In 2016 the results of the survey were further analyzed, and a number of opportunities to improve our existing outreach programs were identified. One item of note from the survey results indicated that more emphasis was required to ensure public awareness of Ontario One Call. Of the 36 LDC's that utilized Utility Pulse for the electrical safety awareness survey, PUC Distribution scored the highest with an awareness score of 86%.

In an effort to improve the Ontario One Call awareness, PUC approved a budget in 2016 (for 2017) to purchase promotional Dig Safe decals for the entire operations fleet. Additionally, in partnership with the Association of Electrical Utility Professionals (AEUSP), PUC contributed to the production of a series of Electricity Safety videos for television broadcast in our service area.

PUC Distribution continues to look for every opportunity to communicate and engage with the public to promote electrical safety awareness in our service area. Below are examples of PUC Distribution's public safety communication initiatives:

- Elementary School Electrical Safety Program (Caution and Chance) for Grade 3 – 5 within our geographic service territory. Participation included 24 schools. (73 classes, and 1,874 students)
- Advanced Research & Technology Innovation Expo (ARTIE) (approx. 360 students and their teachers participated)
- Sault Ste. Marie Science Festival (approx. 500 adults and children attended)
- Sault Ste. Marie PUC website – Safety tab with particular activities aimed at educating young people on electrical safety

DSP-related: The DSP includes a variety of system renewal projects that are driven by system reliability, public and worker safety. In addition, the DSP includes ongoing operating costs to support community and public safety engagement.

Future Considerations: PUC has identified the importance of continuing the Caution and Chance Electrical Safety Program and ensuring that Public Service Announcements along with other advertising are utilized to promote safety as a top priority. PUC will also ensure that customers understand the validity of safety behind projects, such as those included in the DSP, by providing more detail and clarification of projects driven by safety.

b. **INFORMATION SESSIONS**

i. Sault Ste. Marie Public Library (April 2017)

Purpose: PUC has received a variety of customer comments regarding issues with bills being too high, and requests to help with lowering utility costs, through customer care calls, surveys, and event interactions. PUC advertised and held a free informational workshop hosted at the Centennial Library. This was timed in accordance with the recent news from the OEB about disconnection bans. The workshop was divided into two parts; the first part focused on breaking down an average PUC bill and explaining how the charges are set. The second part of the workshop provided customers information and ideas to control their energy usage, which included Save on Energy tips and tools.

Initiated By: PUC, (Community Engagement and CDM teams) in partnership with the Sault Ste. Marie Public Library

Participants: There were approximately 40 attendees. Both the Communications and Conservation teams were on-site to speak with customers and answer any questions they had regarding the industry, and PUC's electrical distribution services. The Q&A period allowed customers to share concerns about rates, rising electricity costs, and overall customers mentioned they were pleased with the amount of information supplied.

Nature and Timing of Deliverables: PUC's objective to inform and engage customers was delivered precisely after the media release of the disconnection ban. It is the organization's responsibility to act as a key ambassador for the public, when delivering information that will affect them or their bills.

DSP-related: The DSP was not directly affected by this engagement opportunity, it does take into account the overall concern from customers about affordability by keeping the proposed rate increase as low as practical while focusing on necessary system renewal.

Future Considerations: We have identified future opportunities to increase the number of sessions held and plan to target different groups and organizations like service clubs and the local Chamber of Commerce (business customers).

ii. Community Energy Learning Series Presentations (February 2017)

Purpose: PUC identified a need through customer interactions, to address assistance needed to lower bills, understand bill charges, and the electricity industry and its operations. The PUC was involved with the SSM Innovation Centre, as its Energy Innovation Hub conducted by the Smart Energy Business Strategist who provided public presentations to increase "energy education" using industry facts/trends to reduce energy consumption through energy efficiency and conservation. The overall goal was to improve understanding of consumption habits, tips on lighting, air sealing, appliances, insulating, water heating, heating and cooling, windows and alternative energy technologies available such as solar panels. One presentation focused on understanding what goes into the cost of electricity**,** geared toward the general public and people who desire a greater understanding of what goes into their electricity bill while discussing both government and consumer forces impacting the cost of electricity. The other presentation focused on how to use less energy and save money since the residential cost of electricity has risen significantly in the past decade. Its goal was to teach homeowners and businesses how to save energy and money.

Initiated By: Sault Ste. Marie Innovation Centre, in association with the PUC

Participants: There were approximately 15 attendees.

Nature and Timing of Deliverables: The SSM Innovation Centre recognized that there was a need during the winter months to educate the public about conservation, alternative energy sources, and the electricity industry.

DSP-related: The DSP was not directly affected by this engagement opportunity, it does take into account the overall concern from customers about affordability by keeping the proposed rate increase as low as practical while focusing on necessary system renewal.

Future Considerations: We will continue to develop new partnership opportunities where these types of presentations can be delivered to the community. PUC will utilize advertising and promotions to assist with future events, as the sessions had low attendance.

iii. Neighbourhood Project Meetings

Purpose: In 2017, PUC held customer consultations in neighbourhoods affected by the system renewal projects. PUC engaged customers to discuss the overall program objectives, as well as logistics and possible impact to their property. The consultations were aimed to speak with customers about rear-lot pole replacement and underground conversion for pad-mount equipment location placement.

Initiated By: PUC

Participants: There were approximately 20 of customers spoken to.

Nature and Timing of Deliverables: PUC's objective was to inform and engage with customers through individual consultations before work began. The feedback was positive; the project was completed successfully and with customer involvement in the decision-making process.

DSP-related: The neighbourhood consultations confirm that the execution of projects was enhanced by including this form of customer engagement, and will be included in all future projects.

Future Considerations: PUC found that the one-on-one engagement not only led to a successful project but also improved the level of customer satisfaction from those impacted. We have identified future opportunities to incorporate these interactions on upcoming infrastructure renewal projects, like those mentioned in the DSP. PUC will need to restructure its engagement, and ensure that consultations occur with work planners, engineers, and eventually filter through a standardized engagement process involving customers.

iv. Focus Groups (2016 and 2017)

Purpose: Focus groups were conducted to promote the HEAR (Home Energy Assessment and Retrofit), CDM pilot program and obtain qualitative research data about the current perception of PUC and the Save on Energy program. The first focus group was geared to addressing the substantial amount of homes in Northern Ontario that utilize electric heat. The second focus group was conducted to help improve marketing communications for both residential and small business customers.

Initiated By: PUC, in partnership with the Customer First (group of LDC's)

Participants: 16 respondents, the group was mixed with residential and small business individuals. The customers involved in the focus groups use mostly electric heat in their homes and identified that as their main source of heating.

Nature and Timing of Deliverables: Customers state that utilizing electric heat as their main source of heating in Northern Ontario is costly, ranging anywhere from $100 to $500/per month. This pilot program offered residential home assessments and the installation of programmable thermostats, low flow shower heads, pipe wrap, and block timers.

DSP-related: The DSP was not directly affected by the focus groups.

Future Considerations: PUC has been approached by the local college to partner with their Public Relations and Event Management program to conduct future focus groups on a wide range of energy-related issues.

Focus Group Findings/Results:
The focus group results show that some PUC customers believe they are doing as much as possible to save energy; most commonly by switching light bulbs, using Time-Of-Use savings, and turning off or unplugging unused equipment/machinery. Some are utilizing technology, and interest in capabilities to do so is high with participants. Most thought that some of the large-scale efforts, such as renovations, may not be worth up-front costs vs. the length of time it would take to recoup as an investment.

The participant's overall impression is favourable towards the LDC being the preferred face of energy saving programs in comparison to the Government, whom they associate larger negative issues with Ontario's electrical system. Customers wanted to see relevant comparisons between older vs. newer high-efficiency appliances, before/after cost-savings, detailed usage based on specific electronic/appliance, testimonials from home/businesses that have utilized the program, technology that provides warnings for excessive usage and specific targets for each customer (E.g. Restaurant owners with fridges, coolers, stoves and apartments with refrigerators, air conditioners, etc.).

The CDM department at PUC provided a testimonial from a local automotive dealership that utilized an energy efficiency program to capitalize on lighting savings for its business. We have identified future opportunities that include a customer-focused survey in our COS Application to present opinions and feedback to the Ontario Energy Board; acting as a voice for the customer to the Government. Customers stated that PUC priorities should be: ensuring fair and competitive rates, enhancing quality and reliability of electricity services and ensuring the electrical infrastructure is maintained for future generations.

CUSTOMER ENGAGEMENT (Informal)

PUC's informal customer engagement program includes; industry-related events, community event partnerships, and awareness programs that allow PUC to connect with its customers. PUC utilizes these engagement opportunities to interact with customers, listening to their concerns, and maintaining a presence in the community it serves.

a. COMMUNITY EVENT PARTICIPATION

i. Retail Product Consultation Coupon Campaigns

Through the focus group, PUC customers mentioned that they are unsure what to change or upgrade in their home/business to increase energy efficiency. PUC's CDM team supports the retail product coupon and consultation campaign, where it works alongside local hardware and home supply stores, to promote energy efficient products, provide coupons to purchase those items and provide conservation tips. The customers were pleased with the amount of conservation knowledge received and small improvements such as changing their light bulbs that they could do.

ii. Bush plane Days Festival

This engagement opportunity supports the community's need for social responsibility and is scheduled in September, so we can allocate this time to speak with families about back-to-school consumption habits, new assistance programs available, and provide electrical safety tips to children. The Canadian Bushplane Heritage Centre draws thousands for its Annual Bushplane Days Festival. We provide information about power outages, line work, energy awareness, Caution and Chance for children, and offer giveaways such as TOU stickers.

iii. Rotary Fest Summer Festival

This customer outreach supports the community's need for corporate social responsibility, community sponsorship, and fostering the growth of community festivals. This event is scheduled in the summer with the Rotary Service Club, and we utilize this opportunity to promote children's electrical safety, program assistance for families, and sign-up people for available programs.

iv. Home and Trade Shows

The customer engagement during the Annual Home and Trade Show in our community promotes maintenance and sustainability for home and businesses. During this event, we are able to communicate with customers that may not visit or call PUC offices. This opportunity enables face-to-face communications in an intimate setting for people to ask questions and feel comfortable doing so. Most customers wanted information about rates, the cost of electricity, and how to save. PUC staff offer information about the Save on Energy/HEAR program, CDM initiatives, and explain the time-of-use, smart meter operations, online services such as Customer Connect, capital projects, and sign-up customers for save-on-energy programs when eligible.

v. Caution and Chance Electrical Safety Awareness Program



Safety is a top priority for PUC operations. Internally, PUC fosters a culture of safety across the entire organization and continues to support community awareness through safety campaigns such as "Give Our Workers a Brake" and "Call Before You Dig.". Since 1995, PUC has invested in the Caution and Chance Electrical Safety program. This educational program supports our organization's priority of safety, starting with children in elementary schools. These safety awareness presentations are conducted at local schools by our employees. We attribute, in part, our high score in the public safety awareness survey, (86%), to this investment and commitment to safety education and awareness.

vi. Chamber of Commerce Business Networking Events

The survey and focus group responses from business customers wanted more information to assist in lower costs and increasing energy efficiency. The CDM team provided business customer support, awareness and program eligibility to minimize costs. There was a breakfast event and presentations for small business incentive information, such as lighting, retro-fit programs and save on energy promotions. We have identified future opportunities that include increased involvement with Chamber of Commerce events to reach a broader business network, open discussion about business issues, and promote the Save on Energy brand.

COMMUNITY SUPPORT

PUC believes in sustaining a positive relationship with the community it serves, and social responsibility as an organization. The following engagement activities relate to PUC's charitable involvement in the community, as we take into account how important our customers feel about giving back to the community. Along with various event sponsorships, these are some of the charitable events that PUC is involved in:

a. The Sault Ste. Marie Downtown Association

PUC employees install banners year round on streetlights in the downtown sector. PUC is also a proud sponsor of the DTA outdoor street party festival event that includes live bands, music, food and beverage, and activities.

b. SSM Community Tree Lighting sponsorship

PUC employees attend the lighting of the community Christmas tree and sponsor the star in recognition of the energy savings, especially during the holidays

c. Sault Ste. Marie Christmas Lighting Awards Program

PUC co-sponsors this event that encourages community pride and recognizes the efforts of residents who light up their home/business for the Christmas season. Winners are awarded a plaque and a credit on their PUC bill.

d. The Lung Association Festival of Trees

PUC employees submit a decorated holiday tree with energy efficient products (thermostats, power bars, lighting, and a PUC electricity credit) in support of the Lung Association

e. SSM Santa Claus Parade

PUC employees decorate a line truck and volunteer for the annual local holiday tradition

f. Bon Soo Festival (event sponsorship)

PUC sponsors the area's largest winter carnival tradition, which has been around since 1964.

g. ARCH Hospice

The PUC Employee Association fundraised over $7,500 for ARCH through an annual golf tournament. The Association was formed in 1976 to look after the welfare of its colleagues, consists of 9 representatives from various departments across the utility, and has a current membership total of 148, out of 178 employees.

h. Christmas Safety Breakfast

This PUC employee event includes a donation of canned goods for the Local Sault Ste. Marie Food Bank.

i. United Way

From 2008 to 2016, **$301,222** has been raised by PUC employees, and Corporate has matched contributions.

j. LEAP program

PUC Distribution participates in the LEAP Emergency Financial Assistance Program, delivered by United Way - Community Assistance Trust. The funds provided by PUC to the United Way are used locally to provide grants to eligible low-income customers of PUC Distribution that qualify. Since 2012, we have donated over $130,000 to the program, supporting customers who have difficulty paying their electricity bills.

COMMUNICATION

Through customer interactions, engagement activities and community support initiatives, we have identified one of the most important customer needs is to keep our customers informed. Information about operational transparency, capital projects, bill changes, regulations, service improvements and what our company is doing to ensure we can provide safe, reliable, and efficient electrical service to the community. Community refers to those affected by decisions made by our organization, and also our stakeholders in a community-owned asset. PUC considers "Engagement" as a continuum of community involvement, moving towards greater community collaboration and evolving as a partnership.

As a proud community partner for the last 100 years, we maintain that we provide a safe, reliable, and efficient electrical distribution system to our service territory. It is our responsibility as a community-owned asset to deliver service, provide information, and continue to communicate with those affected by our

operations. Communication is a key element to share knowledge, inform of any changes, and develop a trusting relationship with our customers.

a. Communications and Community Engagement FTE (Full-time Employee)

PUC understands the need for improved communications with customers to ensure we are encouraging their feedback and growing as a customer-driven utility. PUC has established the role of a full-time, community engagement and communications employee, who was hired to focus on outreach in daily operations, both internal and external. The Supervisor of Customer Engagement was trained in public relations and has shown advocacy for customers when speaking to the media about concerns, and providing clarification on PUC operations that the public can understand. This pro-active and dedicated voice works alongside the management team, engineering, customer care and CDM to promote energy literacy, industry changes and transparency in PUC operations for customers.

This ensures that communication flows from PUC, to inform and educate customers through the various channels. The role encompasses community engagement through public speaking events, media releases, and escalated customer care issues. Most importantly, the position represents the centralized source for information and knowledge of operations to relay to media and the public. We have released information that speaks to a variety of operational issues, as well as industry changes. For example, Public Service Announcements about electrical safety, and media releases that provide knowledge about the Ontario Energy Board disconnect legislative changes.

b. Power Outages

Through customer interactions, PUC has recognized that our customers are concerned about response times, waiting for assistance during outages, and reliability.

i. The implementation and utilization of smart meter data provided an opportunity to leverage these assets for improvement. Today, we are able to utilize the AMI data to provide Outage and Restoration alerts to the Operations and Customer Care staff to efficiently dispatch crews in advance of the “wait until they call” approach. This helps to ensure that PUC is pro-active in delivering service. This also provides System Operators with a mapping view to help identify the precise area and feeders that are impacted for a direct response. We have identified future opportunities to enhance these systems that include the development of a mapping view for customer access.

ii. During an outage, customers would call in and become upset when they received a busy signal or long wait times, during an already stressful time. In response to these concerns, PUC upgraded the phone system to increase capabilities of handling more customer calls. This meant that customers would not have to hear a busy signal, and could be connected to a representative. Upgrading the system allowed for more calls to be handled with an expanded call sorting and queue capability to assist with managing customer calls. It also introduced an automated messaging service that can be customized to detail the current situation. “We are aware of the current power outage in the Queen Street area, and crews are currently on site working to restore power.”

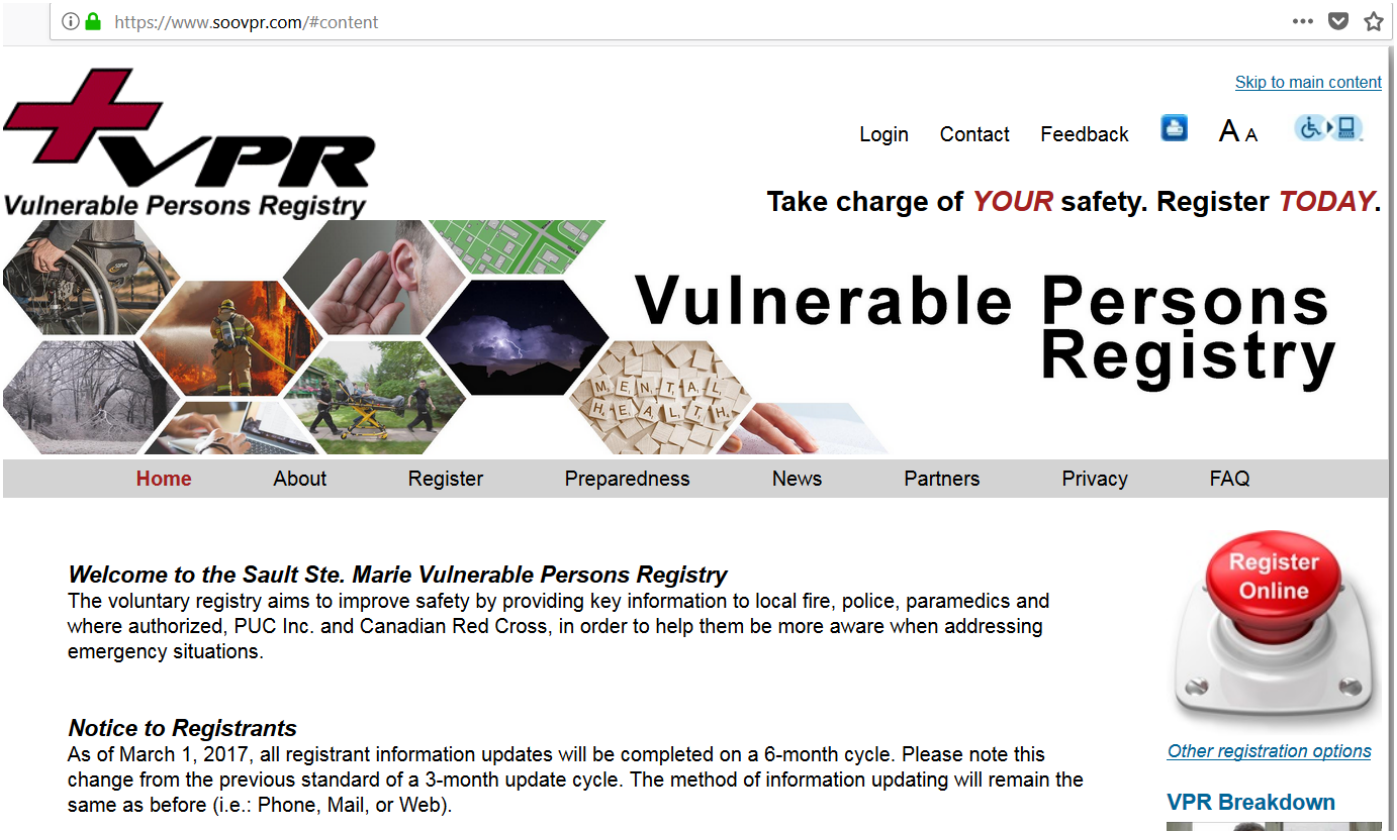
iii. While improvements were made to the emergency, unplanned outage notification system, customers expressed the desire for improvements to be made in PUC's planned outage notification process. PUC addressed these concerns by developing the Atlas Notification System. Implementing this new system required the planning and incorporation of three different components including a geographic mapping system, PUC's customer information database and an automated dialing system. The Atlas Notification System is three separate systems; a geographic information system (GIS), PUC's customer information database and an Interactive Voice Response system (auto-dialer). When work involving service interruption to customers is being planned, PUC staff will identify which area will be affected by the disruption. The electric meters in the identified area will be cross-referenced with the PUC customer database, and a call list will be compiled. That list will be used by the auto-dialer to notify affected customers

We have identified future opportunities that include the ability to increase notification through various devices, for example, text messages, or emails to alert customers of a power outage in their area. We would also like to include an option for communication with renters/multi-renters/apartment buildings with single meter so that those directly affected are contacted, and the onus does not fall directly on the landlord or building owner.

c. Vulnerable Person's Registry (VPR)

PUC services a community with an ageing mature demographic. With this in mind, PUC partnered with the Canadian Red Cross and the SSM Community Geomatics Centre for an innovative service for vulnerable persons. This significant customer-focused initiative utilizes the AMI outage information system to provide vital information to emergency responders. The cooperation of all three entities created a confidential database for "Vulnerable Person Registration" that links to PUC's GIS, providing an email alert to Operations and Customer Care staff whenever an outage impacts a VPR customer. If a VPR customer registers with this service, their status becomes a part of PUC's operational planning and response. This has proven to be of immense value during planned outages to look for additional options when practical for these customers and especially vital during emergency restoration. A standard operating procedure has been developed in cooperation with local emergency services that includes escalation criteria for weather conditions and duration, which allows PUC operations to contact first responders to provide VPR check-ins and support when required. This program can be used by first responders in localized emergency situations including but not limited to; extended power outages, Fire and 911 response, and boil water advisories. It sets a new standard of care, concern, and responsiveness for persons with disabilities who may experience emergencies in our community.

www.soovpr.com



d. Website

Through our community engagement activities, Customer Care department interactions, as well as the 2017 Utility Pulse survey results noting that "83% of customers access the internet for information," PUC has recognized the need for online services. Over the last few years, PUC has invested in a variety of online initiatives to improve communication with customers, based on an increase in online usage and the advantages of self-serve options, like reviewing usage online. Our commitment to serving customers includes providing access to information, 24/7/365.

We strive to improve our online presence through website enhancements that improve the overall customer experience, making it user-friendly, visually stimulating and encouraging customers to monitor usage. In 2013, comments received through customer interactions suggested a user-friendly website experience was needed. There was a need for improvement in the communication of outages and duration information. PUC updated the website with a refresh project which also included a customer-focused portal; Customer Connect. This refresh included improved outage notification, project awareness, tree trimming work areas, conservation awareness, and program initiatives for homes and businesses that were easily accessible.

We have identified future opportunities that include the development of an outage map/grid, specific page for system renewal projects (as included in capital investment projects detailed in DSP), social media links for conservation awareness promotions, and self-serve options such as opening, closing and relocating an account.

e. Social Media

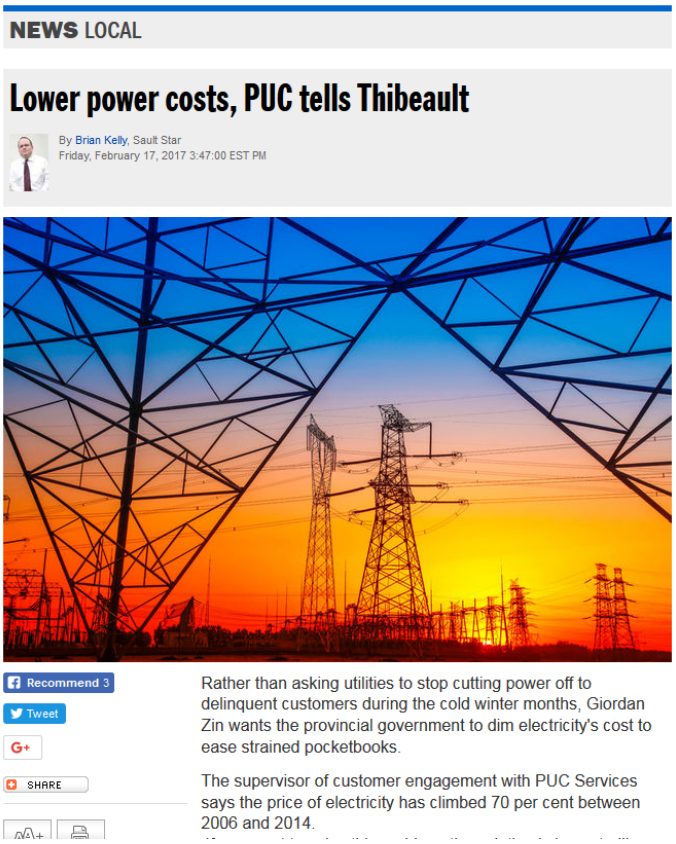
The introduction of Social Media accounts such as Facebook, in 2013 and Twitter in 2012 allowed PUC to communicate with a larger online audience and reach different target markets with messages about; worker safety, electrical shock and safety, home renovation/upgrades, energy-efficient products, electricity industry information, conservation tips, community engagement events such as retail product consults/coupon giveaways, and charitable fundraising.

f. Public Notices

Customers want a reliable electrical service, and through interactions have spoken to the inconvenience of outages. PUC ensures that any changes in service are communicated so that our customers are able to pre-plan beforehand. We provide advanced notification of planned projects and service modifications. These include, but are not limited to hand-delivered notices in the affected neighbourhood. We have identified future opportunities that include possible email notifications and text messages to serve as a convenient method for PUC to communicate any project information or service changes that may affect them.

g. Media Interviews/Press Releases

Our PUC Communications is tasked with continuously providing customers with information about changes that may affect their bill, projects, consumption rates, operations, regulations/legislation and current energy industry events. In order to ensure that information reaches all of our audiences, we utilize multiple media channels. This communication is supported through media relations within our community, such as media interviews and press releases. These interviews are arranged through the Department and include the CEO and the Supervisor of Communications/Community Engagement. Each interview is an opportunity for PUC to address and speak to issues affecting customers.



NEWS LOCAL

Lower power costs, PUC tells Thibeault

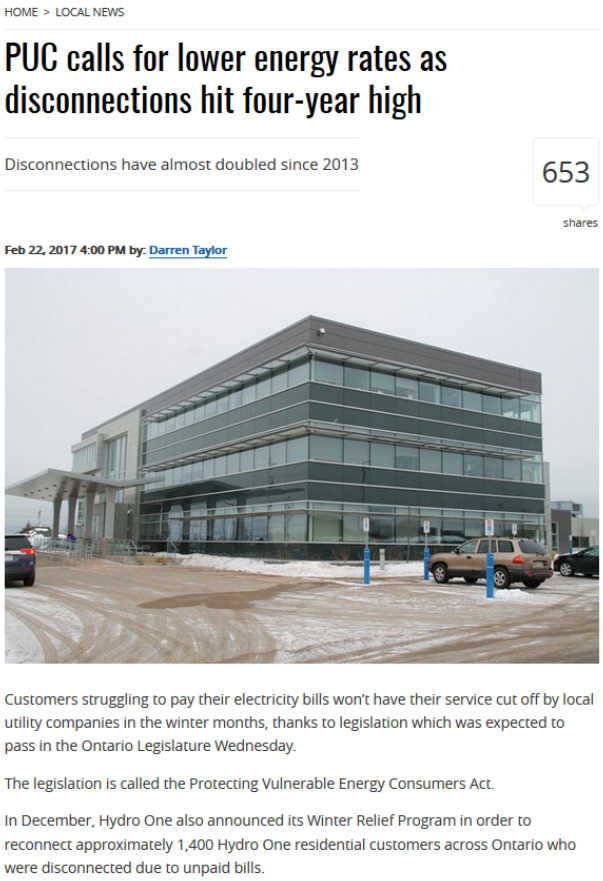
By Brian Kelly, Sault Star
Friday, February 17, 2017 3:47:00 EST PM

Recommend 3 Tweet G+ SHARE

Rather than asking utilities to stop cutting power off to delinquent customers during the cold winter months, Giordan Zin wants the provincial government to dim electricity's cost to ease strained pocketbooks.

The supervisor of customer engagement with PUC Services says the price of electricity has climbed 70 per cent between 2006 and 2014.

http://www.saultstar.com/2017/02/17/lower-power-costs-puc-tells-thibeault



HOME > LOCAL NEWS

PUC calls for lower energy rates as disconnections hit four-year high

Disconnections have almost doubled since 2013

653 shares

Feb 22, 2017 4:00 PM by: Darren Taylor

Customers struggling to pay their electricity bills won't have their service cut off by local utility companies in the winter months, thanks to legislation which was expected to pass in the Ontario Legislature Wednesday.

The legislation is called the Protecting Vulnerable Energy Consumers Act.

In December, Hydro One also announced its Winter Relief Program in order to reconnect approximately 1,400 Hydro One residential customers across Ontario who were disconnected due to unpaid bills.

https://www.sootoday.com/local-news/puc-calls-for-lower-energy-rates-as-disconnections-hit-four-year-high-543044

h. Advertising

To ensure we provide our customers with the most updated information, we support local advertising through a variety of outlets such as print, online, radio and television. The advertising campaigns promote our community brand as well as building awareness with conservation tips, PSA's (Public Service Announcements), Time-of-Use, tree trimming and worker safety to name a few. We ensure that there is a strategic alignment with our advertising campaigns that promote significant issues to our customers. For example, during December, we advise of high costs due to entertaining during the holidays, holiday lighting and TOU changes. We have identified future opportunities that include obtaining specific feedback from customers for communication outlet preference.

i. Bill Inserts

We include inserts for increased communication about provincial legislation, regulations, the Atlas program, services, changes, conservation program initiatives, etc. and it is a direct line of communication to the customers, as well as a record of information provided through paperwork. We have identified future opportunities that include adding this as a focus group initiative. This would allow us to understand how many customers find this method of communication efficient as well as the overall retention of information.

j. Paperless Billing (E-Billing)

This initiative was introduced based on customer feedback and the importance of reducing the environmental footprint and improving accessibility. Those registered will receive their monthly bill via email. Some customers have made comments about the availability of credit card payment. Based on the cost analysis in comparison to the number of customer requests received, covering those costs would be at a loss for the organization at this time. However, in the event of a collection situation where they need to pay with credit card, there is a fee that accompanies using that payment method and a third party that provides the availability of the credit card service. We have identified future opportunities that include a paperless billing campaign, introducing bill email reminders which have the customers' bill in a short breakdown so they can pay or log on to Customer Connect and review.

CUSTOMER CARE/CONTROL

Over the years, electricity costs have risen, and customer concerns have escalated as a result. Our challenge as a local utility is to encourage customers to curb their consumption habits and help them manage their electricity usage. PUC understands that each touchpoint with customers on the phone, website, social media, or in-person influences what customers think and feel about our organization. It is our responsibility to provide information to help customers understand how the system works, what costs are associated with operations, as well as lowering their electricity bill.

Over the last 3 years, PUC's Customer Service department has rebranded itself to Customer Care, with more focus on caring for the customer rather than just serving the customer. The website, inbound/outbound scripts, and templates have shifted to represent this value. PUC will continue to encourage its employees to see the value in every customer interaction, in order to enhance customer experiences, and overall public perception of the PUC.

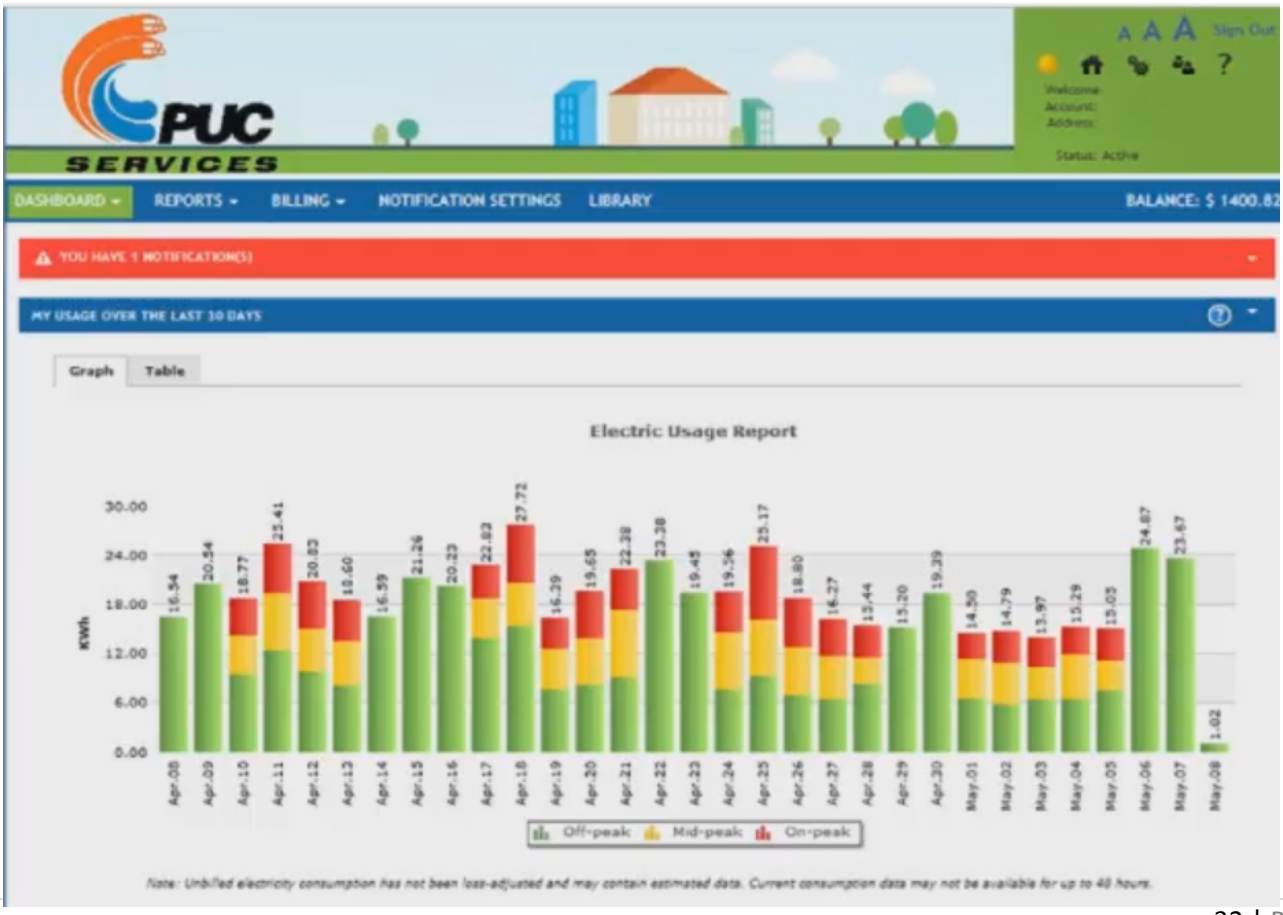
Our commitment to customer care goes beyond the Customer Care department; it involves the entire organization and includes our core value of responsiveness to our community. We are fortunate enough to have a local office where a customer can speak to an engineer about a technical question, a billing representative for their statement, a planner about upcoming neighbourhood projects, and even a forestry technician about tree trimming near their home or business, all in one place of business.

The top 3 customer issues we receive are; high bills, billing inquiries and moving of services. We often get questions about government initiatives as well, such as the 25% rebate. PUC recognizes that there is room for improvement. According to the 2017 Utility Pulse survey, “68% believe we adapt well to changes in customer expectations.” Customers want “their problem solved quickly, to have a personal interaction with a customer care representative and to speak with a knowledgeable and courteous customer care representative.” “73% said that PUC is customer-focused and treats customers as if they’re valued.” To improve our operations to support a customer-driven culture, we have invested in the following elements so customers can be reassured that we are here to serve them.

a. Customer Connect

PUC receives the most calls concerning the cost of electricity during the winter months when the weather is the coldest. The Customer Connect platform was designed to help those customers monitor their consumption, bill, and review historical data to stay informed about their energy usage. As of November 2017, 8,596 or 26% of customers are signed up for Customer Connect.

The Customer Care department also uses this tool directly with customers as a walk-through for understanding the bill, and specific charges on dates or times of high utilization. It allows for real-time access, to advise people of various spikes, TOU, and in-person, to add a visual representation of consumption, when a customer comes to the office. The customers can better understand once provided with the knowledge, and possibly change consumption habits if necessary, or realize why their bill charges were at the amounts listed. This element is critical to operations during the winter months in the North when the weather is coldest, and costs are highest.



b. Front Desk Support

PUC ensures that customer care is offered through face-to-face interaction, based on our population and ageing demographics. Customers are able to come to the administrative offices and go through their bill step-by-step with a Customer Care Representative. In a city with a mature demographic, this asset is becoming more vital to our operations as each day passes. PUC has the advantage of having local representatives that can speak to the same environment, especially during the cold winter months when everyone is trying to keep warm. When customers are experiencing difficulty, we offer a walk-in service. This helps us to ensure we take the extra time to better serve our customers' needs and help them with understanding industry and operational information. This element has worked efficiently with the Customer Connect online tool so that our representatives can provide a visual representation of what the electrical usage looks like with hourly, daily and weekly viewpoints. Although we offer this walk-in service, many customers would prefer online and self-serve options. We have identified future opportunities that include more online forms and email correspondence such as contracts, as currently, we request customers come into the office to sign a paper contract that is kept on file.

c. Customer Service Training

PUC decided to invest in customer care training for the entire organization in 2017 after a variety of customer interactions, and engagement opportunities reflected customers' negative perception of the utility. Our entire organization underwent CARE Training (Customers Are the Reason we Exist). This interactive training program encouraged customer-centred operations, customer loyalty, communication skills, resolving customer disputes and concerns as well as changing the overall attitude towards customers, understanding the vital role they have in our operations. This training was provided by the Simul Corporation, in mixed department group sessions and was well-received by staff. The training provided staff with up-to-date insights into customer satisfaction and what customers were saying about the utility. We have identified future opportunities which include annual investment in company-wide refresh training with the C.A.R.E. model to improve customer satisfaction and support the commitment to customer care being one of our top priorities.

d. Internal Training

Customers want to have knowledgeable, professional staff that can provide the most up-to-date information about the industry and changes that may affect them. PUC holds monthly staff meetings that include the latest industry and company information such as the winter disconnects, OEB backgrounders and any rate changes that may affect a customer's bill. Our Conservation (CDM) and Line departments provide the Customer Care, Billing and Metering departments with presentations to review upcoming program initiatives offered. The Line department provides the Customer Care department with presentations to help with terminology and understanding of the electrical distribution system. Additionally, our Customer Care department representatives shadow the Metering and Line departments in field operations so that they can experience firsthand, the exact equipment and processes that are used. This enables representatives to speak with customers if they are having trouble with affordability, understanding the electrical system, and any other technical questions that may require a broader field of experience to answer. Throughout the organization, our employees, from frontline to management, are encouraged to respond to escalated customer concerns and to assist with finding solutions. This reassures our customers that they are a priority.

e. Customer Information System (CIS) and MCare (Electronic Service Orders)

PUC received customer complaints that the metering service process did not work efficiently with the Customer Service Order paperwork, and ensuring reliability with meter reading times. Customer Care, Billing and Metering departments were receiving complaints about the meters being wrong, incorrect readings, billing issues, and overall dissatisfaction with the meter service. In conjunction with the Customer Connect upgrade, PUC decided to upgrade the Customer Information System from its existing "Harris" system to the "Northstar" system. This provided electronic metering service orders and real-time electronic communication with Meter department staff to improve services. This has improved communication and response times between the customer, Customer Care department, and the meter reading technicians.

CONCLUSION

PUC Distribution believes that its customers trust in its ability to make decisions to ensure a safe, reliable and efficient electrical service is delivered to their homes and businesses. Through various customer engagement opportunities, PUC has been able to implement customer-driven initiatives into our operations.

These activities include customer satisfaction and strategic planning surveys, focus groups, information sessions, residential and business awareness events, and innovative community partnerships to drive sustainable growth. We have supported customer-driven initiatives such as Customer Connect, the online usage platform, Atlas, the outage notification system,

As a local distribution company, PUC has developed and enhanced its customer engagement over the last five years. We understand that customers would rather not pay more for their electricity bills; however, the reality is that the ageing infrastructure in our community needs to be revitalized, in order to provide that reliability.

Each interaction with customers allows us to grow as a community-owned asset, and better align our operations with our customers' needs. As such, PUC will continue to search for new opportunities to engage customers and provide them access to more information about our activities, which will allow for an improved flow of communication.

EXHIBIT 1 – Cost of Service Survey Master Script

Introduction Page (text for screen, not verbally – LANDING PAGE)

Welcome,
Thank you for participating in PUC Distribution's Customer Engagement Survey.

We are applying to the Ontario Energy Board (OEB) for approval to increase PUC's portion of the electricity bill, also known as the delivery rate. If approved, a (750kWh) residential electricity bill would increase by approximately $2.17 per month.

The purpose of this survey is to give you a better understanding of the details behind our proposed rate increase, and to provide you with an opportunity to share your feedback.

The survey is broken down into a few sections. Most sections have a short video that provides a quick summary and are followed by a "YOUR SAY" segment. These segments provide you with the opportunity to share your thoughts.

Please keep in mind that all numbers are preliminary and may change prior to final submission as we consider customer feedback.

Your feedback will also be shared with the OEB, the independent energy regulator that ultimately approves the rate that PUC can charge on the bill.

Help us get to know you a little better!

1) What are the first three digits of your postal code?
    a. P6A
    b. P6B
    c. P6C
    d. Other (please specify)

2) What is your age?
    a. 18 to 34
    b. 35 to 54
    c. 55 to 74
    d. 75 +
    e. Prefer not to answer

3) Are you?
    a. Male
    b. Female
    c. Other
    d. Prefer not to answer

4) Which of the following best describes you?
    a. Homeowner
    b. Tenant (Renter)
    c. Landlord
    d. Business
    e. Other (Please specify)

5) Including yourself, how many people live in your household?
    a. 1
    b. 2
    c. 3
    d. 4
    e. 5+

6) Where do you live within PUC Distribution's service area?
    a. City of Sault Ste. Marie
    b. Prince Township
    c. Dennis Township
    d. Batchewana First Nation Rankin Reserve
    e. I reside outside of PUC's service territory
    (Please specify your location below)

7) If you are a PUC customer, what services do you currently receive from PUC?
    a. Electricity
    b. Electricity and Water
    c. I am not a PUC customer.

8) How satisfied are you with the overall service(s) you receive?
    a. Very satisfied
    b. Somewhat satisfied
    c. Neither satisfied or dissatisfied
    d. Somewhat dissatisfied
    e. Very dissatisfied
    f. Not applicable

    Please explain why you feel that way.

9) Which of the following is your **primary** source of heating?
    a. Electricity
    b. Natural Gas
    c. Propane
    d. Oil
    e. Wood
    f. I'm not sure
    g. Other (Please specify)

Please watch the following video before completing the questions below. Ensure your volume is on and turned up, so you can hear the information. Closed Captioning is available for those that need it.

INTRODUCTION - VIDEO 1

Hi, I'm Jordan and I'd like to thank you for participating in PUC Distribution's customer engagement survey. This survey is part of our Cost of Service application to the Ontario Energy Board. The Ontario Energy Board (or OEB) regulates the electricity industry in the province. This includes local distribution companies, or LDC's, like PUC.

The OEB's Cost of Service application occurs every five years and determines what each LDC can charge for its distribution rate. PUC is currently applying to the OEB for approval to increase the average residential electricity bill, by approximately $2.17 per month.

This short survey will guide you through our Cost of Service Application, and more importantly, get your feedback on it. We are looking for valuable information from you, our customer, to better understand your needs and how we can provide you with the best possible service.

YOUR SAY

10) Among the following PUC priorities, place what you think each is in order of importance. Using the scale 1 = Most Important and 5 = Least Important
    - Community Engagement/Communication
    - Providing more information during power outages
    - Maintaining reliable electrical service (e.g. prevent/reduce power outages)
    - Keep rates as low as practical while maintaining good quality electrical service
    - Helping customers reduce/manage consumption and by doing so reducing costs

11) Where do you currently find information on topics such as electricity rates, conservation tips, and consumption/usage information? Please select **ALL** that apply.
    a. Local Media
    b. Call, Email or In-person at the PUC Office
    c. PUC Website
    d. PUC Information Booths (Home/Trade Shows)
    e. Open Houses/Information Sessions
    f. Government of Ontario Website
    g. Ontario Energy Board Website
    h. Other (Please specify)

Please watch this video before completing the questions below. Please ensure your volume is on so you can hear the information. Closed captioning is available for those that need it to participate.

YOUR ELECTRICITY BILL – VIDEO 2

Let's start by taking a look at your electricity bill.
Did you know that every charge on your hydro bill is either mandated by the provincial government or regulated by the Ontario Energy Board?
Here is a breakdown of a PUC customer's 2017 electricity bill, using the Provincial average of 750kwh per month. The bill is made up of 5 components:

- Energy, which = 53% of the bill - this is the cost of the actual electricity you use. PUC does not keep this amount; instead, it's paid to provincial agencies.
- Distribution = 27% of the bill. This is PUC's portion; it covers the costs of the poles, wires and transformers that are used to deliver electricity.
- Transmission, which = 4%. This covers the cost of transmitting high voltage electricity from generation sites across the province, to our community. PUC does not keep this charge as it is paid to the transmission companies.
- Regulatory fees, which = 4% PUC does not keep this, as this fee must be paid to regulators
- and Taxes, which = 12%

You'll notice that the delivery line from your bill isn't on this chart, that's because the delivery charge is made up of both the distribution and transmission fees. As you can see, PUC's portion (or the distribution charge) is only about 27% of the total bill. This charge is the ONLY fee that PUC has any control over and the ONLY charge we keep - the remaining 73% of the bill is passed on to power generation companies, transmission companies, the provincial government and regulatory agencies.

This means, 27% of the electricity bill covers the total cost of operating our community's utility. Everything from financing capital projects, day-to-day operations, infrastructure replacement, and employee wages. To help put this in perspective; 27¢ from every dollar on the electricity bill covers the entire cost of operating PUC's electric utility.

YOUR SAY

12) Do you think the amount ($0.27 cents from each dollar on an average 750kWh residential bill), that PUC Distribution keeps for operating and maintaining safe, local electricity service is reasonable?
    a. Very Reasonable
    b. Somewhat Reasonable
    c. Neither Reasonable or Unreasonable
    d. Somewhat Unreasonable
    e. Very Unreasonable

    Please explain why you feel that way.

13) How familiar are you with the Time-Of-Use information about off-peak, on-peak and mid-peak usage rates?
    For example, holidays are off-peak and if the holiday is on a weekend then the following weekday is off-peak in lieu of.
    a. Very familiar
    b. Somewhat familiar
    c. Not very familiar
    d. Not at all familiar

Please watch this video before completing the questions below. Please ensure your volume is on so you can hear the information. Closed captioning is available for those that need it to participate.

ELECTRICAL DISTRIBUTION OVERVIEW – VIDEO 3

Did you know that PUC Distribution's service territory includes more than just the City of Sault Ste. Marie? It actually extends to parts of Prince and Dennis Townships and the Batchewana First Nation Rankin Reserve.

Before we get into what we need the rate increase for, let's talk about how electricity is delivered across PUC's service territory to your home or business.

We receive power from the provincial transmission grid at 115 thousand volts which supply our two transformer stations. Here we step-down the voltage to 34 thousand volts and transmit it to 14 neighbourhood distribution stations or substations. These substations further reduce power to 12 thousand volts or in some cases, 4 thousand volts. Power is then delivered to neighbourhoods through overhead or underground wires along the streets and roadways. The last step in the journey is the individual distribution transformers that lower the voltage one more time, before the electricity is used by you, the customer.

YOUR SAY

14) When you have an electrical service issue, what is your preferred method to contact PUC for assistance?
Please select **ALL** that apply.
    a. Email
    b. Phone
    c. Mail
    d. Social Media (e.g. Facebook, Twitter)
    e. Website
    f. In-Person
    g. Other (Please specify)

15) If you've ever contacted PUC about an electrical service issue, how satisfied were you with the customer care you received?
    a. Very satisfied
    b. Somewhat satisfied
    c. Neither satisfied nor dissatisfied
    d. Somewhat dissatisfied
    e. Very dissatisfied
    f. Not Applicable
    Please explain why you feel that way.

16) If you've ever had a PUC Field Representative visit your home or business concerning an electrical service issue (e.g. power outage, overhead or underground system work), how satisfied were you with the service level provided?
    a. Very satisfied
    b. Somewhat satisfied
    c. Neither satisfied nor dissatisfied
    d. Somewhat dissatisfied
    e. Very dissatisfied
    f. Not Applicable
    Please explain why you feel that way.

17) As we move forward, PUC Distribution would like to improve communications and engagement with our community. Of the following ideas, what would you prefer to see?
    a. Neighbourhood meetings in advance of planned projects
    b. PUC Open House (e.g. Tour PUC facilities and meet electricity professionals)
    c. Online Chat Portal (Connected to PUC website)
    d. Conservation Information Booths (e.g. Bushplane Days, RotaryFest)
    e. Other (Please specify)

Please watch this video before completing the questions below. Please ensure your volume is on so you can hear the information. Closed captioning is available for those that need it to participate.

PROPOSED RATE INCREASE – VIDEO 4

Now that we've reviewed the bill breakdown, let's take a look at our proposed rate increase.
Since 2013's application, our service revenue requirements have increased, by approximately $3.3 million, up from $18.8 million to $22.1 million. This is largely driven by increases in operation, maintenance, and administrative costs, as well as a number of infrastructure renewal projects.

While we understand the concerns around rising electricity costs, the unfortunate reality is, additional financial resources are needed for us to continue addressing our community's electrical distribution needs.

If the rate increase is approved, an average residential customer, using the Provincial average of 750 kWh a month, will see an approximate two dollar and seventeen cent increase on their monthly electricity bill. This represents a sixteen point five percent increase on the PUC portion of the bill or a two point one percent increase on the total electricity bill. And, for the duration of the following five-years – distribution rate increases would be held to less than the rate of inflation.

As mentioned earlier, this rate increase is largely driven by increased costs which we will be breaking down in the upcoming videos.

YOUR SAY

18) In order to improve our customer communication, please choose your **preferred** method for PUC to communicate with you.
    a. TV (e.g. CTV)
    b. Online (e.g. Sootoday)
    c. Print (e.g. Sault Star)
    d. Radio
    e. PUC Website
    f. Social Media
    g. Information Sessions
    h. Bill Inserts
    i. Email Blasts
    j. Other (Please specify)

19) To increase awareness of electricity usage, PUC offers an online energy usage tool called, Customer Connect. Have you ever used it to monitor your hourly, daily and weekly electrical usage?

    (If you would like more information about Customer Connect, please contact Customer Care at 705-759-6522)
    a. Yes, I find it useful to visually track usage.
    b. Yes, I've used it a few times.
    c. I don't have access to a computer.
    d. No, I'm not interested in online services.

20) Have you visited the PUC website for any of the following in the last 6 months? Please select **ALL** that apply.
    If not, please choose Not Applicable.
    a. Customer Connect
    b. Paperless Billing (E-Billing)
    c. Conservation Programs and Information
    d. Power Outage Inquiry
    e. Project Information Search (e.g. Overhead line work in your neighbourhood)
    f. Not Applicable
    g. Other (Please specify)

Please watch this video before completing the questions below. Please ensure your volume is on so you can hear the information. Closed captioning is available for those that need it to participate.

OPERATIONS, MAINTENANCE & ADMINISTRATION – VIDEO 5

In previous videos, we've talked about the 3.3 million dollar increase in our service revenue requirements. Approximately, 61% or 2 million dollars of this increase is driven by operational, maintenance and administrative costs. Here's a breakdown of those costs:

21 percent of the 2 million dollar increase is made up of new Regulatory Requirements.
These include things like:

- PCB chemical testing for overhead transformers, to ensure they are all PCB-free by 2025.
- New meter reading requirements for large general service customers.
- Newly mandated initiatives, like the Under Frequency Load Shedding program – which is designed to improve the reliability of the Provincial electricity grid.
- And finally, the hiring of an additional staff member to assist with growing OEB requirements – all contribute to the increased costs in Regulatory Requirements

10 percent of the increase covers the rising cost of utilities since our last application. This accounts for basic utilities for the transmission and distribution stations, and the administrative building and service center.

5 percent of the increase is a result of the growing cost of utilizing the Smart Meter Network, which include things like the automated meter-reading software fees.

Another 7 percent of the increase is needed to cover Bad Debt, which has grown, due to the rising number of customers unable to pay their electricity bill. This can be attributed to the combination of; the rising cost of electricity, the moratorium on winter disconnections, and the state of our local economy.

9 percent of the increase accounts for the growing costs of meeting Industry Regulations. For example, costs for things like; OEB Annual Assessments, Cost of Service Applications, and mandated Customer Engagement Programs have all grown since 2012.

7 percent of the increase covers the cost to operate our Vegetation Management or Tree Trimming program. While, PUC has extended this program to a four-year cycle to reduce costs annually, costs fluctuate based on the total area needing to be cleared, and the number of contractors bidding on that year's cycle.

The remaining 41% of the increase in service revenue requirements is driven largely by inflationary growth in things like; employee wages, benefits, contracted services, insurance costs, and fuel expenses.

YOUR SAY

21) Now that you're familiar with the rising costs associated with our operational, maintenance, and administrative needs. Do you feel you have a better understanding of the proposed rate increase, to cover those costs?
    a. Yes
    b. No
    c. I Need More Information
    d. No Opinion
    Please explain why you feel that way.

Please watch this video before completing the questions below. Please ensure your volume is on so you can hear the information. Closed captioning is available for those that need it to participate.

CAPITAL INVESTMENT PROJECTS – VIDEO 6

As mentioned, operations, maintenance and administrative expenses account for two-thirds of the total service revenue requirement increase. The remainder is driven by Capital Investments in infrastructure renewal. Let's explore some of the infrastructure renewal projects PUC has planned for the next few years.

Probably, the most visible components of the electrical distribution system are the overhead lines and poles. PUC has about 621 km of overhead lines using about twelve thousand, seven hundred poles. Of those, approximately 102 poles have been in service for more than 60 years. Over the next five years, our plan is to replace approximately 150 poles, identified as being in poor or very poor condition.

Additionally, some of the older overhead lines in our system were constructed with a type of copper wire, which no longer meets reliability and safety standards. Our proposed plan would see those lines replaced within the next ten years.

The underground electrical distribution system is comprised of approximately 122 kms of cable, 30 kms of which are approaching the end of their service life. Additionally, underground infrastructure like switches, concrete vaults, and submersible transformers are also a priority for replacement based on their condition. Our plan will continue addressing this aging infrastructure, and focus on neighbourhoods with high equipment failure rates.

Substations are a critical part of any electrical system, as they supply entire neighbourhoods with power. A single substation can provide enough power for 2,000 homes. Replacing a sub-station costs approximately three point five million dollars and takes about two years to complete.

It's important to note that the average service life for a transformer is 40 years so special attention needs to be paid to those located within our substations, as 66% of station transformers have been in service longer than 35 years. With that in mind, we plan on replacing two substations by 2022.

Locally, our substations transform electricity from 34 thousand volts to twelve or four thousand volts. Over the last few years, PUC has been converting the four thousand volt system to a twelve thousand volt system. This is because the four thousand volt system is at, or very near, the end of its service life.

PUC is proposing a replacement plan that will completely retire the 4 thousand volt system by 2022; including poles, wires and transformers and replace it with the more efficient and reliable 12 thousand volt system.

YOUR SAY

22) The long-term plan that includes operational and maintenance costs, asset renewal and replacements to ensure reliability and system performance will include a monthly bill price increase.

Which statement best represents your point of view?

a. I would be willing to pay an additional $5-7 on my bill to invest as much as possible into the reliability of the system.
b. I would be willing to pay an additional $3-5 on my bill to invest in operations, and improve the system as quickly as possible.
c. I would be willing to pay an additional $1-3 on my bill if reliability improves through gradual infrastructure renewal.
d. I am NOT willing to pay any additional charges on the PUC portion of my bill knowing that the level of reliability could decline.

Please explain why you feel that way.

23) Now that you're familiar with some of the planned projects, what do you think of the proposed rate increase to support infrastructure investment?
    a. The rate increase should be higher to support an increase in infrastructure investment.
    b. The rate increase proposed is reasonable and I support it.
    c. I don't like it but understand the increase is necessary.
    d. The rate increase is unreasonable and I oppose it.
    e. No opinion

    Please explain why you feel that way.

24) Are you satisfied with the amount of information we provided you in this survey to understand the reasons behind the proposed rate increase?
    a. Yes
    b. No
    c. I Need More Information

    Please explain why you feel that way.

Please watch this video before completing the questions below. Please ensure your volume is on so you can hear the information. Closed captioning is available for those that need it to participate.

POWER OUTAGES AND SYSTEM RELIABILITY – VIDEO 7

Power outages are an unfortunate reality in the electricity industry. That said, at PUC we work very hard to keep outages to a minimum and if required, as short as possible.

One of the annual industry measurements for system reliability is the System Average Interruption Duration Index, or SAIDI. This is measured by the average number of hours the power to a customer is interrupted. In 2016, the total time the average customer was without power was 90 minutes. This is below our target of 112 minutes, per year.

The other annual industry measurement is the System Average Interruption Frequency Index, or SAIFI. This is measured by the average number of times the power to a customer is interrupted.
In 2016, the total number of times the average customer experienced an interruption was 1.4 times. This is well below the target of 2.3 interruptions per year.

As you can see, PUC's reliability metrics are trending in a positive direction. We attribute these results to our ongoing commitment to improving system reliability through infrastructure renewal and a successful vegetation management program, better known as tree trimming.

PUC knows that reliability is important to customers, and that's why we plan to increase our investment in infrastructure renewal to improve system reliability. This will ensure we continue to provide a safe, reliable and efficient electrical system for the community we serve.

YOUR SAY

25) In the past year, how many power outages have you experienced?
    a. None (0)
    b. One or Two (1 or 2)
    c. Two or Three (2 or 3)
    d. More than Three (3 +)

26) What was the longest power outage you had in the past year?
    a. Less than 30 minutes
    b. 30 – 60 minutes
    c. 1 – 1.5 hours
    d. More than 1.5 hours

27) Did you contact PUC about the power outage?
    a. Yes
    b. No
    c. I can't remember

28) If you contacted PUC about a power outage, how satisfied were you with the way PUC responded to the outage?
    a. Very satisfied
    b. Somewhat satisfied
    c. Neither satisfied or dissatisfied
    d. Somewhat dissatisfied
    e. Very dissatisfied
    f. Not Applicable

    Please explain why you feel that way.

29) On average a PUC customer loses power due to outages for less than 90 minutes over the year. Do you feel this level of reliability is?
    a. Very good
    b. Good
    c. Poor
    d. Very poor
    e. No opinion

    Please explain why you feel that way.

Final Thoughts (text for screen, not verbally)

YOUR SAY

30) Is there anything in particular that PUC Distribution can do to improve its electricity service for you?

31) Outstanding Questions – Do you have any further **questions, concerns you would like to share?**

Thank you for your time, we know how valuable it is and we appreciate your feedback and input.

Click on the link below to enter for a chance to win one (1) of five (5) credits of $100.00 (One hundred Canadian dollars), towards your PUC bill.

MUST be a PUC customer (residential or business) at the time of the draw.

Limit one (1) entry per household.

Please note that survey responses are NOT associated with your draw entry information.

https://www.surveymonkey.com/r/WIN100PUCCREDIT

Thank you!

PUC Distribution Inc. Customer Engagement Survey Contest

Official Contest Rules

The Customer Engagement Survey contest is sponsored and administered by PUC Services Inc. ("PUC") on behalf of PUC Distribution Inc. The contest begins on January, 9, 2018 at 11:00 a.m. E.S.T. and ends on February 11, 2018 at 11:59 E.S.T. By participating, entrants agree to be bound by these contest rules and the decisions of PUC, which are binding and final, without right of appeal, on all matters relating to this Contest. Contest is subject to all applicable federal, provincial and local laws. Void where prohibited by law. **NO PURCHASE IS NECESSARY**.

Eligibility

- Must be a PUC customer (residential or business) at the time of the draw.
- Must be 18 years of age or older.
- Limit one (1) entry per household.
- All Contest entries must be submitted by February 11, 2018 at 11:59 E.S.T. to be eligible to win.
- By entering this contest, all participants are deemed to have accepted the Contest Rules.
- Must not be an employee, representative, agent or Board member of PUC Services Inc., PUC Distribution Inc., or any of its affiliates.
- Must correctly answer a skill-testing question on the contest entry page.
  (2x4) + (100/5)

How to Enter

During the contest period, participants may enter the contest once by completing the PUC Distribution Customer Engagement Survey. Once participants have completed the survey, there will be a Survey Draw Link to click on that will redirect participants to the contest entry page where participants will fill in and complete the requested information. Participants must also correctly answer a skill-testing question on the contest entry page in order to be eligible to win. Participants are allowed only one entry to the contest. Multiple entries from the same participant or from the same household will void all of such participant's or participants' entries.

Prizes

There are five (5), $100 bill credit grand prizes, to be randomly drawn on February 12, 2018 at 9:00 a.m. E.S.T., after the Contest Period has ended. The total approximate value of all prizes is $500.00. The Prize will be applied directly to the winner's next PUC electricity bill and will appear as a line item on their bill. PUC will notify the winner when the credit has been applied. The prize must be accepted as is, has no cash value and is non-transferable. Winners must attend PUC head office located at 500 Second Line East, Sault Ste. Marie, Ontario and show proof of identification, along with their account number, to claim their prize. The $100 credit will be applied to the winner's next PUC bill.

Odds of Winning

The odds of winning a prize depends on the total number of eligible entries received during the contest period.

How to Win

There will be a random drawing for each of the five (5) grand prizes conducted by PUC at the following date, time and location: February 12, 2018 at 9:00 a.m. EST at PUC Head Office located at 500 Second Line East, Sault Ste. Marie, Ontario. Five Entrants will be selected from all eligible entries received. The selected Entrants must also provide proof of identity (driver's license or other government issued photo identification). Failure to provide such proof of identity shall disqualify the selected Entrant.

Notification

Selected Entrants will be notified by telephone using the phone number provided in the Contest entry form. If a participant is identified as a selected Entrant then such selected Entrant must respond to claim the prize within ten (10) business days. A prize will be forfeited if it goes unclaimed for ten (10) business days, from the date a phone call is made. In the event the prize is not claimed within the allotted time period or the selected Entrant is disqualified or the prize is otherwise forfeited, PUC will re-draw and choose a new selected Entrant randomly from all remaining entries until a winner is declared. PUC shall have no liability if the winner notification is lost, intercepted or not received by a selected Entrant

Use of Information

All personal information collected herein will be used only for the administration of determining the eligibility for the contest draw in accordance with the requirements of Municipal Freedom of Information and Protection of Privacy Act (MFIPPA). By participating in this Contest, Contest winners are deemed to have consented to the disclosure of their names and photos, without compensation, being included in any publicity carried out by PUC. Each participant consents to the collection, use and disclosure of his/her personal information for the purposes of this Contest and grants permission for PUC to disclose personal information to its related and affiliated companies, contractors and agents to assist in the Contest.

Limitation of Liability

PUC assumes no responsibility for late, lost, incomplete, incorrect, delayed or misdirected entries or for any failure of any website, for any problems or technical malfunction of any computer online systems, servers, access providers, computer equipment, software, failure of any e-mail or entry to be received by PUC on account of technical problems or traffic congestion on the Internet or at any website, or any combination thereof, including any injury or damage to a participant's or any other person's computer, mobile device or other electronic device related to or resulting from this Contest. In the event the Contest is compromised by a virus, non-authorized human intervention, tampering or other causes beyond reasonable control of PUC which corrupts or impairs the administration, security, fairness or proper operation of the Contest, PUC reserves the right in its sole discretion to suspend, modify or terminate the Contest.

General Conditions

Participants agree, by participating, (I) to be bound by the terms of these Contest Rules and the decisions of PUC, which are final and binding, without right of appeal, on all matters relating to this Contest; and (ii) to indemnify, release and hold harmless PUC and its parent companies, affiliates, subsidiaries, officers, directors, agents, representatives and employees from any liability, for any injuries, losses or damages of any kind, including death, to persons, or property resulting in whole or in part, directly or indirectly, from participation in this Contest or acceptance, misuse, non-use or use of any Prize. By accepting a Prize, winners release PUC from any and all liability, loss or damage incurred with respect to the awarding, receipt, or possession of any prize, and acknowledge that PUC is not responsible in any way for any issues in connection with the prizes awarded or any losses, damages, or claims relating to the Contest. Any and all issues, questions, disputes, claims and causes of action arising out of this contest or any prize award shall be resolved in accordance with the laws of the Province of Ontario.

If there are any questions or concerns about the contest rules and regulations, please contact: customer.care@ssmpuc.com or 705-759-6522, Monday – Friday, 9:00 a.m. E.S.T. to 4:30 p.m. E.S.T.

EXHIBIT 2 – COST OF SERVICE SURVEY STORYBOARD

APPENDIX 12

PUC Distribution's Business Plan

PUC Distribution Inc.

Business Plan

2017 to 2021

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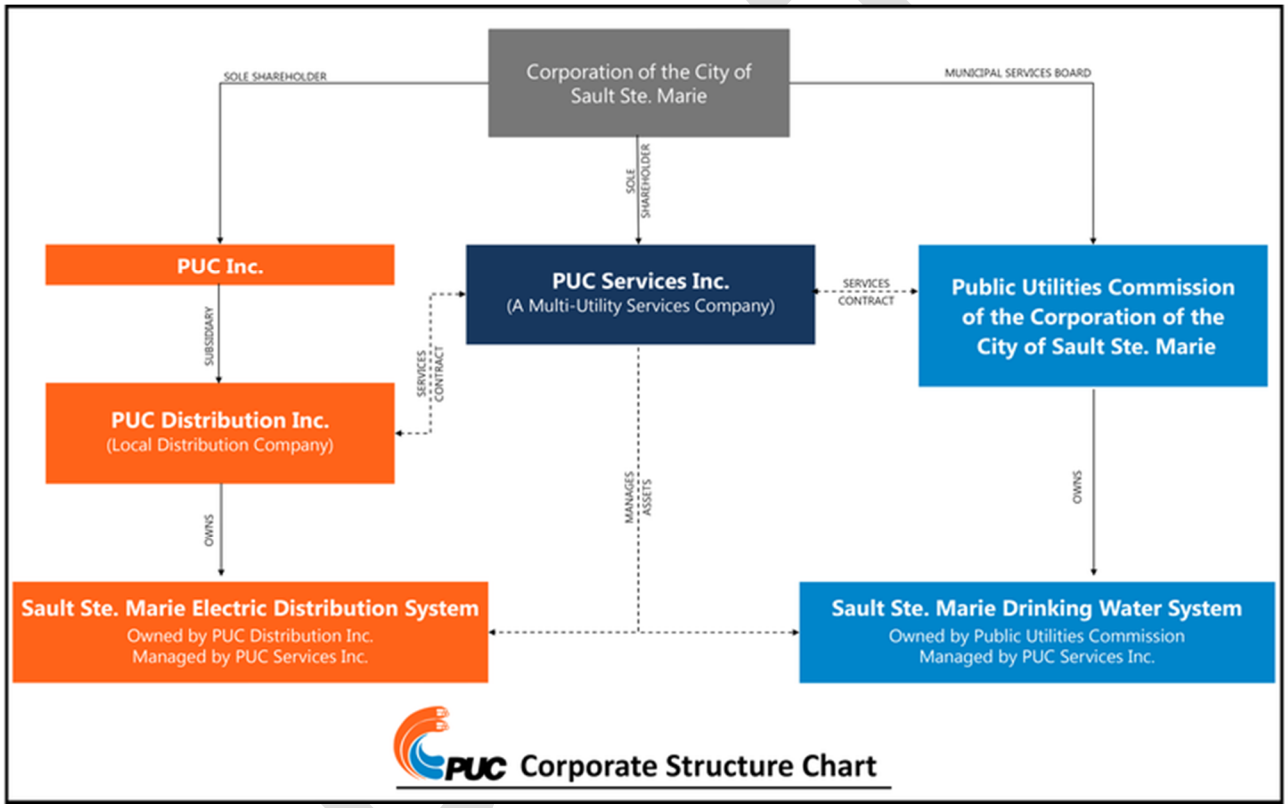
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1. SUMMARY

1.1 Introduction

In accordance with Section 142 of the *Electricity Act, 1998* the existing electricity assets of the City of Sault Ste. Marie Public Utilities Commission were transferred to PUC Distribution Inc. ("**PUC**"), a "for profit" corporation incorporated under the Ontario *Business Corporations Act*. PUC is 100% owned by PUC Inc., a holding company owned 100% by the City of Sault Ste. Marie (the City). The transfer was completed in 2000 and as required by Bill 210 in 2003, the City, through Council resolution, affirmed that the electric utility should remain an OBCA "for profit" corporation. The ownership of PUC Distribution is illustrated in the diagram below.



PUC is a local distribution company (LDC) licenced to distribute electricity in its service territory which includes most of Sault Ste. Marie, Batchewana First Nation (Rankin Reserve), Prince Township and parts of Dennis Township. In addition to distributing electricity, PUC is the default supplier of energy to customers within its service territory that do not contract with a retailer for their energy supply.

PUC must operate its business in compliance with all applicable laws, including the *Electricity Act, 1998*, the *Ontario Energy Board Act, 1998*, the Ontario *Business Corporations Act*, and the rules, policies and requirements of the Ontario Energy Board (the "**OEB**") including the

Distribution System Code, the Affiliate Relationships Code, the Retail Settlement Code, the Standard Supply Service Code, the Accounting Procedures Handbook and the Uniform System of Accounts as well as the applicable Rate Handbook and Filing Requirements.

Although it does not pay corporate income taxes, as a municipally owned licenced LDC in the province of Ontario, PUC is required to pay Payments in Lieu of Taxes (PILS) to the province. The amount payable is generally speaking calculated based on Federal and Provincial tax rules for corporations.

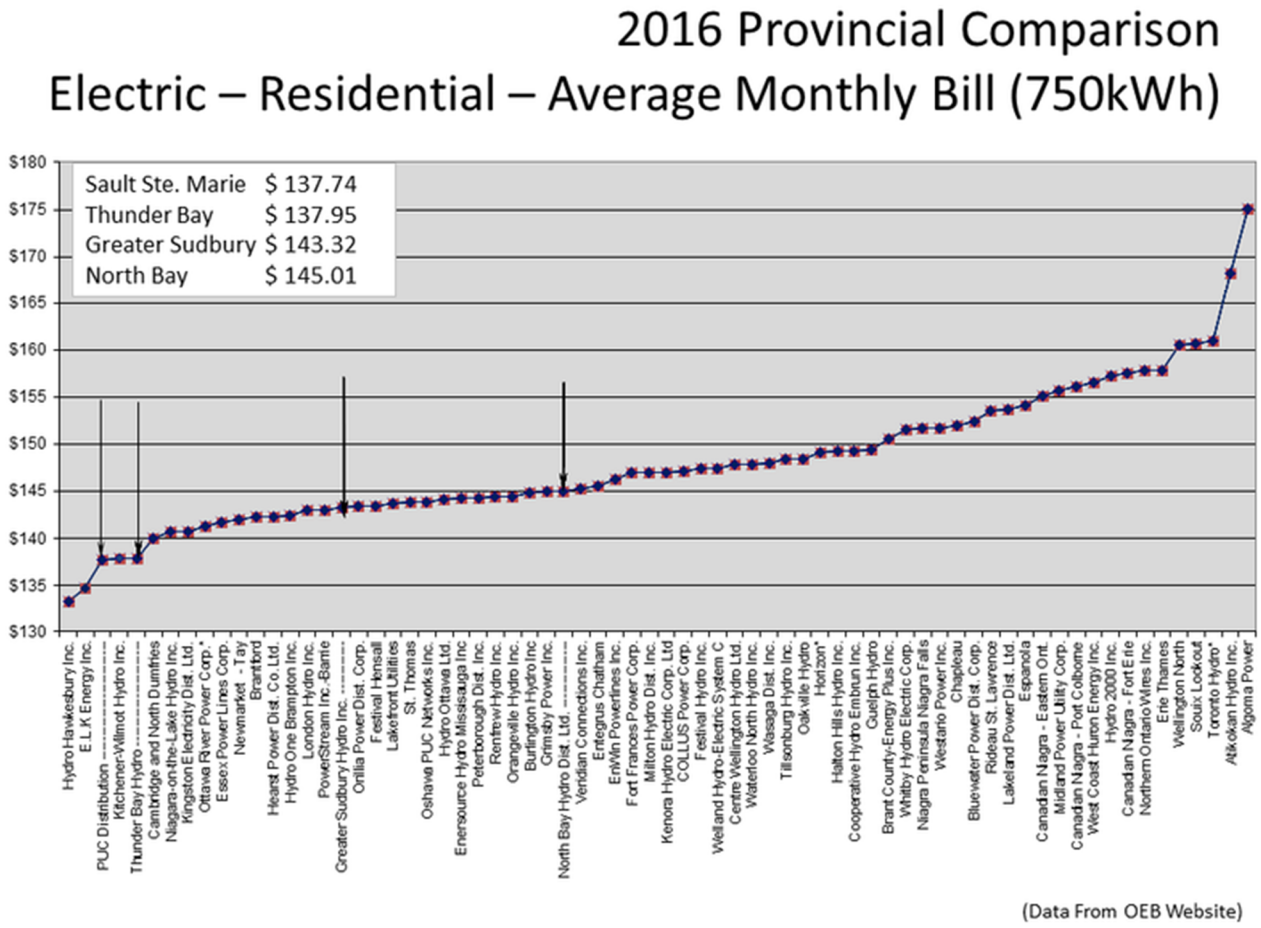
1.2 PUC's Distribution System And Business

PUC serves an area of approximately 342 square kilometers, with a combined population of approximately 73,368. The service territory includes approximately 29,700 residential customers and 3,800 general service customers for a total of 33,500 customers.

PUC owns and operates two transformer stations which step down power received from the transmitter at 115kV to 34.5kV. The 34.5kV feeders supply a total of 14 distribution stations which step down power to 12.5kV and 4.2kV. PUC employs approximately 430 km of 3-phase and approximately 270 kms of 1-phase overhead lines operating at 115kV, 34.5kV, 12.5kV, 7.2kV, 4.2kV, 2.4kV and low voltage. The underground distribution network consists of approximately 73 km of 3-phase cable circuits and approximately 83 km of 1-phase cable circuits. There are approximately 12,600 wood poles and 80 other types of poles, 6,622 transformers and 33,417 revenue meters in service.

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In 2016, the average (provincial) residential customer (750kWh) of PUC paid the 3rd lowest rates in the Province of Ontario, as reported by the Ontario Energy Board. This is illustrated in the diagram below.



1.3 Corporate Mission

In 2016, PUC conducted a strategic direction survey which included participation from the public, employees, the Board of Directors and other stakeholders (the City of Sault Ste. Marie, Prince Township, Batchewana First Nation). Feedback from the survey was incorporated into an update of PUC's Mission, Vision and Core Values, as described below. The PUC Mission, Vision and Core Values were further refined to ensure alignment with the OEB's *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (RRFE) four outcomes:

- Customer Focus – services are provided in a manner that responds to identified needs and preferences of customers
- Operational Effectiveness – continuous improvement in productivity and cost performance is achieved while LDCs deliver on system reliability and quality objectives
- Public Policy Responsiveness – LDCs deliver on obligations mandated by government
- Financial Performance – financial viability is maintained and savings from operational effectiveness are sustainable

Mission

PUC's mission is to provide cost effective, efficient, safe and reliable delivery of high quality energy services and solutions consistent with customer needs and preferences.

Vision

To be recognized as a progressive electric distribution company committed to delivering value, innovation, prosperity and excellence.

Core Values

Responsive – We believe that to be recognized as the leading service provider we need to not only respond quickly to our customers' needs but also anticipate and be proactive with our service delivery

Ownership – to promote organizational excellence, everyone is empowered to take individual accountability and inspired to assume personal responsibility within the organization

Safety – PUC has been and will continue to be a strong advocate for safety within our community. Safety is our top priority and we will never compromise on the safety of our employees or our community

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Innovative –We believe that in order to succeed in advancing a climate of innovation we must seek out new approaches or technologies, and apply ingenuity and creativity when confronting challenges

Entrepreneurial – We recognize that exploring new business ventures and diversifying our service offerings is the best way to ensure we not only earn a fair return for our shareholder, but grow and add value as a community owned asset

In conjunction with the Mission, Vision and Core Values, PUC has set three strategic Focus Areas and Aspirations:

Focus Area & Aspiration (AAA)	Strategic Long Term Goals	Strategy to Achieve Success	2018 Objective
Customers	Achieve an A+ customer satisfaction rating Meet or exceed all scorecard targets.	Improve service quality Improve customer focus (customer satisfaction, communication, engagement, education)	Achieve scorecard targets (discussed below) Achieve CDM targets, implement customer engagement plan
Employees	Be recognized as one of Canada's top 100 employers Organizational Safety Excellence	Implement P3SO organizational transformation (employee engagement, training) Continuous improvement of safety culture and performance through our Integrated Safety	Continue accountability leadership training to all staff Achieve an employee engagement survey rating of 70% Zero major (high risk) lost time

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		Management Program	incidents
Shareholder	Achieve OEB deemed return on equity for shareholder Increase value of the company	Explore permitted business opportunities Ensure sustainability of assets and system Productivity/business process improvements	Achieve budgeted EBITDA Achieve budgeted capital expenditures File cost of service rate application Pursue business opportunities

PUC Distribution's Mission, Vision, Core Values and Focus Areas and Aspirations align with the OEB's RRFE. Customer focus and engagement is a key component of PUC's current and future plans.

1.4 Financial Plan Assumptions

This report summarizes PUC's estimated results for 2017, 2018 budget for the cost of service rate application (test year budget) and 2019 – 2021 projections.

The Business Plan is based on the following assumptions and constraints:

1. A distribution revenue increase in 2018 of approximately $1.6 million based on the estimated increase as a result of the cost of service rate application to be submitted (rebased recovery of requested OM&A expenses, depreciation expense and PILs expense, plus a return on asset base as prescribed by the OEB).
2. An annual distribution revenue increase in 2019 to 2021 of 1.5% based on the estimated Incentive Rate Mechanism (IRM) annual increase leading up to the next Cost of Service rate application in 2023. The projections are also based on a flat consumption level – no growth or decline in consumption volume over the projection period.
3. Subsequent to 2018, expense increases are estimated at 1.5% per year.
4. Prudent investment in distribution plant so that ratepayers of Sault Ste. Marie

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and surrounding service territory can continue to be provided with excellent service and reliability.

5. Continued improvement to customer communication and engagement to best serve our customers.
6. Long-term view of return on shareholder investments.
7. Continuing to seek improvements in productivity in order to provide current and future mandated levels of service to customers at a cost at inflation or less.
8. Managing economic and political uncertainty.
9. Increasing working capital to between 20 to 30 days.
10. Reducing the debt to equity ratio over a number of years to the OEB deemed level of 60/40%.

1.5 Summary of PUC Distribution's 2017 & 2018 Budgets and 2019 – 2021 Projections

PUC's Financial Plan summary is provided in the attached Appendix. The Plan provides for prudent and sustainable investment in core business operations and subject to certain material risks, results in the following metrics:

$ Millions	2017 Budget	2018 Budget	2019 Projection	2020 Projection	2021 Projection
Net Income	$0.5	$1.6	$2.7	$2.7	$2.7
Return on Equity - estimated	3.48%	5.75%	8.02%	7.63%	7.41%
Return on Equity –deemed	8.98%	8.98%	8.78%	8.78%	8.78%
Interest payments to S/H	$1.6	$1.6	$1.6	$1.6	$1.6
Dividends to S/H	$0.0	$0.0	$0.0	$0.0	$0.0
Capital Expenditures net of Contributed Capital	$4.7	$5.4	$8.6	$5.4	$6.2

- Interest payments based on current debt structure with the shareholder (PUC Inc.); and
- Continued investment in capital renewal projects, investment in distribution station in 2019.

2. BUSINESS RISKS AND MITIGATION

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2.1 Material Risks to the Business Plan and Potential Mitigation

The following business risks, should they materialize, could pressure operations and earnings over the Business Plan horizon:

1. The impact of milder winter and cooler summers (compared to normal weather) on distribution revenue and maintenance costs. In addition, conservation impacts on revenue, and the degree of success in meeting its CDM targets.
2. Weakness in the local economic environment and the associated increase in credit risk. Although not a direct customer of PUC, the current Companies' Creditors Arrangement Act (CCAA) status of the City's largest employer poses a material risk to PUC because of its impact on residents and businesses that are customers of PUC.
3. Equipment failures that affect service to customers.
4. Adverse impacts from lower rates that may arise if the OEB changes the IRM formula parameters. This could result in distribution earnings and cash flow being lower than the rate increases assumed in the Business Plan.
5. Acquisition and retention of human resources to support existing operations and new business requirements.
6. Performance of the company's information technology systems, especially in the area of cybersecurity attacks.
7. The impact of the current municipal and provincial political environments on LDCs.
8. Other unforeseen events (e.g., storms) that could adversely impact the electricity distribution system.

Weather

Weather-related and conservation impacts on distribution revenue in the short term cannot be mitigated, although evidence will be presented in the Cost of Service Rates ("CoS") Application to mitigate the future impact of a weather-related declining revenue trend. Such evidence would generally include the presentation of weather-normalized data as a basis for determining customer specific volumetric distribution charges. In addition, the transition to a fully fixed monthly charge for residential customers will be complete in 2020, resulting in approximately 67% of distribution revenue being fixed monthly.

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Mitigation of *material* weather-related impacts on costs (e.g., ice storms, high winds, etc.) could be achieved through a request for a z-factor adjustment application before the OEB. The current materiality threshold for z-factor adjustments is 0.5% of distribution revenue, which for PUC is approximately $0.1 million per event.

Local Economy and Credit Risks

LDCs in general are challenged to mitigate short-term impacts on distribution revenue resulting from declining consumption and poor economic conditions. These aspects are considered to be normal business risks for LDCs, and must be taken into consideration as part of the development of the load forecast underlying the CoS Application.

As part of its CoS Application, PUC will provide a load forecast that is derived from a multi-factor, single-equation econometric model. The model includes such parameters as weather (Heating degree-days, Cooling degree-days), economic output (manufacturing GDP growth), calendar variables (days in month, number of peak hours), and a "dummy" variable (blackout parameter). LDCs are exposed to revenue reductions during the IRM rate periods from variances between actual loads and the load forecasts underlying distribution rates at the time of the CoS filing.

PUC faces credit risk primarily from non-payment of hydro bills by large customers. The company's revenue is earned from a broad base of customers, it does not earn a significant amount of revenue from any single customer. PUC's top ten customers represent 6% of distribution revenue, which exposes PUC to credit risk from these customers. However, of the top ten customers, only one is a private corporation, the remainder are federal, provincial or municipal government entities which reduces the credit risk. Additionally, a systemic downturn in the global, provincial or local economy could also expose PUC to credit risk from other customer classes. To deal with this risk, PUC has adopted credit policies as permitted by OEB regulation that result in a reasonable level of credit risk mitigation. The company does not provide significant electric service to the major industries in the municipality, however, financial difficulties at these companies could adversely affect the entire community and thus the distribution utility,

Residential and Small Commercial Customers

Management continues to monitor the OEB's current review of customer service rules and will analyze the financial impact of any code amendments implemented by the OEB. The OEB is currently reviewing the following areas:

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- Restrictions on disconnecting electric service during the winter months for non-payment;
- Length of advance notice prior to a disconnection;
- Bill due dates and late payment charges;
- Security deposits;
- Allocation of payments;
- Equal monthly billing plans and,
- Arrears payment arrangements.

Conservation and Demand Management

Revenue loss from customers' CDM efforts may be mitigated through a Lost Revenue Adjustment Mechanism ("LRAM") application with the OEB to accelerate recoveries of foregone revenue from CDM activities.

Equipment Failure

PUC has recently completed an Asset Management Plan (AMP) and a Distribution System Plan (DSP) and has adopted a systematic plan to replace its aging infrastructure. Equipment failure risk is managed through such programs as the annual tree-trimming program, infrared surveys of plant and equipment, non-destructive pole testing and treatment, oil testing of power transformers, and by maintaining an adequate inventory of replacement parts.

Regulatory Risk

Regulatory risk is the risk that the Province and its regulator, the OEB, could establish a regulatory regime that imposes conditions that significantly reduces the rate of return that can be earned by electricity distributors. In addition, the ability to maintain the distribution system depends on, among other factors, the OEB allowing recovery of the operating, maintenance and capital costs required in the future. Lower rates arising from these types of changes could result in distribution earnings and cash flow being lower than the rate increases assumed in the Business Plan.

Failing to continually be aware of and applying changing government regulations is also a corporate risk. The company monitors developments in the electricity industry and also relies on the Electricity Distributors Association to monitor and act

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on its behalf. Consultants with expertise in certain fields are utilized as required.

Human Resource Risk

As part of the management service contract with PUC Services Inc., PUC Services Inc. provides the workforce necessary to operate PUC Distribution Inc. Labour disruptions can affect ongoing operations. Collective agreements with the union employees in PUC Services Inc. are in effect until April 30, 2018.

PUC Services Inc., like others in the utility services industry, faces a significant number of retirements over the next several years. The retirement of individuals in technical, trades and management positions will result in the loss of a large pool of expertise, therefore where practical replacements are hired in advance of projected retirements to promote the transfer of knowledge.

Technology Risk

The use and complexity of the company's electronic infrastructure continues to increase and its reliability and security are critical to all areas of operation. As part of the management service contract with PUC Services Inc., an information technology (IT) department oversees networks, voice over internet protocol communications, enterprise software, smart meter operation, systems security and other emerging IT issues. In addition, outside resources with expertise in specific areas are utilized as necessary. PUC has a staff training program to address cybersecurity issues and is actively participating in the OEB' current cybersecurity work group.

3. SCORECARD REVIEW

As noted above, the performance outcomes outlined in the RRFE are measured on the LDCs scorecard which is published annually. In 2016 PUC Distribution Inc. (PUC) met or exceeded all prescribed targets for scorecard measures. PUC continued with strong performance in the Customer Focus, Operational Effectiveness and Public Policy Responsiveness areas of our scorecard. A discussion of the scorecard follows the scorecard reproduced below.

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Scorecard - PUC Distribution Inc.

9/11/2017

Performance Outcomes	Performance Categories	Measures	2012	2013	2014	2015	2016	Trend	Target	
									Industry	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	95.80%	96.50%	93.00%	97.20%	98.90%	up	90.00%	
		Scheduled Appointments Met On Time	98.40%	97.10%	95.40%	97.40%	98.30%	up	90.00%	
		Telephone Calls Answered On Time	74.60%	80.90%	81.90%	82.30%	81.30%	up	65.00%	
	Customer Satisfaction	First Contact Resolution			99.89%	99.92%	99.58%			
		Billing Accuracy			99.83%	99.36%	99.97%	up	98.00%	
		Customer Satisfaction Survey Results			In progess	79%	80%			
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				86.00%	86.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]	NI	C	C	C	C	flat		C
		Serious Electrical Incident Index — Number of General Public Incidents	3	1	3	1	0	down		1
		Serious Electrical Incident Index — Rate per 10, 100, 1000 km of line	0.407	0.135	0.405	0.134	0.000	flat		0.151
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]	1.65	1.42	1.19	1.37	1.49	down		1.86
		Average Number of Times that Power to a Customer is Interrupted [2]	2.17	1.78	1.21	1.03	1.41	down		2.32
	Asset Management	Distribution System Plan Implementation Progress			In progress	In Progress	In progress			
	Cost Control	Efficiency Assessment	3	4	4	4	4			
		Total Cost per Customer [3]	$615	$687	$664	$699	$695			
		Total Cost per Km of Line [3]	$27,523	$30,950	$29,886	$31,377	$31,314			
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]				17.18%	52.97%			26.41 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time				0.00%	100.00%			
		New Micro-embedded Generation Facilities Connected On Time		100.00%	100.00%	100.00%		flat	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)	1.19	1.06	1.68	0.90	1.52			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	2.01	1.99	2.42	2.31	2.34			
		Profitability: Regulatory Return on Equity — Deemed (included in rates)	8.57%	8.98%	8.98%	8.98%	8.98%			
		Profitability: Regulatory Return on Equity — Achieved	4.99%	7.00%	5.47%	4.46%	0.98%			

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 fixed 5-year (2010 to 2014) average 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

3.1 Customer Focus

3.1.1 Service Quality

New Residential/Small Business Services Connected on Time

In 2016, PUC Distribution connected 349 eligible low-voltage residential and small business customers (connections under 750 volts) to its distribution system, 98.90% of which were connected within the five-day timeline prescribed by the Ontario Energy Board (OEB). This is a 1.7% increase from the previous year and exceeds the OEB mandated target of 90%.

The improved performance over 2015 can be partly attributed to a reduction in capital works projects which allowed additional resources to focus on low volume connections. PUC Distribution has demonstrated our commitment to continuous improvement through staff education to ensure customer satisfaction is a top priority.

PUC's target for this metric in 2018 is 90%.

Scheduled Appointments Met On Time

In 2016, PUC Distribution scheduled 1,468 appointments with customers to complete customer requested work (e.g. meter installs/removals, service disconnects/reconnects, and meter locates). As a result of our emphasis on customer satisfaction, PUC was able to meet 98.30% of scheduled appointments on time, which exceeds the OEB target of 90%.

PUC's target for this metric in 2018 is 90%.

Telephone Calls Answered On Time

In 2016, PUC Distribution's Customer Care Department received 40,787 calls from its customers. This represents an increase in call volume of approximately 1,900 calls from 2015, due in part, to the utility switching to automated reminder calls for past due accounts. Of the 40,787 calls, a Customer Care Representative answered the call within 30 seconds or less, 81.30% of the time. This result significantly exceeds the OEB mandated 65% target for timely call response.

PUC's target for this metric in 2018 is 75%.

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3.1.2 Customer Satisfaction

First Contact Resolution

PUC Distribution's First Contact Resolution was measured by tracking the number of electric related calls which were escalated to a Senior Customer Care Representative or Supervisor/Manager. This was accomplished by creating two specific call types in our Customer Information System (CIS) which would then be queried to provide the number of customer concerns which were escalated. In 2016, PUC had 40,787 calls, of which, 171 contacts were escalated to a higher level of management. This resulted in a First Contact Resolution percentage of 99.58%. To establish the number of calls which were handled without escalation, the total number of calls which were escalated to a higher level of management was subtracted from the total number of calls received. However, it should be noted that First Contact Resolution can be measured in a variety of ways and further regulatory guidance is necessary in order to achieve meaningful comparable information across electricity distributors.

PUC's target for this metric in 2018 is 99%.

Billing Accuracy

PUC issued approximately 395,000 bills for the period from January 1, 2016 – December 31, 2016, and achieved an accuracy of 99.97%. This score compares favourably to the prescribed OEB target of 98%. PUC continues to monitor its billing accuracy results and processes to identify opportunities for improvement.

PUC's target for this metric in 2018 is 98%.

Customer Satisfaction Survey Results

PUC Distribution engaged the UtilityPulse Division of Simul Corporation to conduct our 2016 customer satisfaction survey. The UtilityPulse Electric Utility Survey is in its 19th year of annual surveys and is used by a significant number of Ontario distributors. The final report on our customer satisfaction survey was received in March 2017, and PUC Distribution received a B+ customer satisfaction score of 80% (post survey result) which is above the Ontario benchmark survey that had a grade of "B". The raw score had a slight increase from our last survey of 79%. The survey asked customers questions on a broad range of topics, including overall satisfaction with reliability, customer service, outages,

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billing and corporate image. These customer satisfaction surveys are an important element in our overall customer engagement strategy providing further insight towards planning and supporting customer service improvement at all levels within PUC Distribution.

PUC's target for this metric in 2019 is "A-".

3.2 Operational Effectiveness

3.2.1 Safety

The Public Safety measure was introduced by the OEB in 2015 and focuses on the safety of the distribution system from a customer's point of view. The Electrical Safety Authority (ESA) provides an assessment as it pertains to Component B – Compliance with Ontario Regulation 22/04 and Component C – Serious Electrical Incident Index.

Safety - Component A – Public Awareness of Electrical Safety

A representative sample of PUC Distribution's service territory population was surveyed in late 2015 to gauge the public's awareness level of key electrical safety concepts related to distribution assets. The purpose of the survey was to provide a benchmark level concerning the public's electrical safety awareness, and identify opportunities where additional education and outreach may be required. The results of the survey were analyzed in 2016, a number of opportunities to improve our existing outreach programs were identified and an action plan was developed.

One item of note from the survey results indicated that more emphasis was required to ensure public awareness of Ontario One Call. In an effort to improve this metric, PUC approved a budget in 2016 (for 2017) to purchase promotional Dig Safe decals for the entire operations fleet, and through participation with the Association of Electrical Utility Professionals (AEUSP) has contributed to the production of a series of Electricity Safety videos for television broadcast in our service area. PUC Distribution continues to look for every opportunity to communicate and engage with the public to promote electrical safety awareness in our service area. Below are examples of PUC Distribution's public safety communication initiatives:

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- Elementary School Electrical Safety Program for Grade 3 – 5 within our geographic service territory. Participation averages 24 schools annually covering approximately 70 classes, and 1,900 students
- Advanced Research & Technology Innovation Expo (ARTIE) (approx. 360 students and their teachers participated)
- Sault Ste. Marie Science Festival (approx. 500 adults and children attended)
- Sault Ste. Marie PUC website – Safety tab with particular activities aimed at educating young people on electrical safety
- Advertisements in the geographic service territory consists of newspaper and radio ads

PUC's target for this metric is to improve each year the survey is undertaken.

Safety - Component B – Compliance with Ontario Regulation 22/04

Ontario Regulation 22/04 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, and specifications and the inspection of construction to ensure there are no undue hazards before they are put in service.

Component B is comprised of an External Audit, a Declaration of Compliance, Due Diligence Inspections, Public Safety Concerns, and Compliance Investigations. ESA evaluates all these elements as a whole to determine the status of compliance. In each of the past four years, PUC Distribution was found to be compliant with Ontario Regulation 22/04 (Electrical Distribution Safety). PUC attributes this continued success to our strong commitment to safety, and adherence to company policies and procedures.

PUC's target for this metric in 2018 is to remain fully compliant with Ontario Regulation 22/04.

Safety - Component C – Serious Electrical Incident Index

Section 12 of Ontario Regulation 22/04 specifies the requirement to report to ESA any serious electrical incident of which they become aware within 48 hours after the occurrence. For the 2016 reporting period, PUC Distribution did not experience any serious electrical incidents.

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To increase public safety awareness, PUC Distribution offers electrical safety awareness outreach via; newspapers, radio, public events, presentations to elementary school students, and detailed hazard awareness presentations to contractors.

PUC's target for this metric in 2018 is to have zero (0) serious electrical incidents reported. This is more aggressive than the OEB scorecard target of 1. In PUC's view, 1 serious electrical incident is 1 too many. Management has its internal target accordingly.

3.2.2 System Reliability

A key change for 2016, as required by the OEB, is the revised reporting of reliability data with respect to Major Events. Specifically the change serves to adjust the reliability data to remove the impact of Major Events. Additionally, distributors are required to report criteria to monitor the distributor's performance related to the Major Event. The 2016 Scorecard system reliability data, excludes both Loss of Supply and Major Events. The adjusted reliability measures capture interruptions caused by circumstances within the distributor's control and are published in the 2016 scorecard. A "Major Event" is defined as an event that is beyond the control of the distributor and is; unforeseeable, unpredictable, unpreventable, or unavoidable. Such events disrupt normal business operations and occur so infrequently that it would be uneconomical to take them into account when designing and operating the distribution system. Such events cause exceptional and/or extensive damage to assets, take significantly longer than usual to repair, and affect a substantial number of customers. In 2016 there were two major event days. The first happened on March 6 (foreign interference) and the second on June 20 (adverse weather).

Average Number of Hours that Power to a Customer is Interrupted

The System Average Interruption Duration Index (SAIDI) of 1.49 in 2016 was below the target of 1.86. There are ongoing efforts to improve reliability including replacing aging infrastructure and improving vegetation management.

PUC's target for SAIDI in 2018 is lower than the OEB distributor target (fixed five year average (2012 -2016)) of 1.42.

Average Number of Times that Power to a Customer is Interrupted

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The System Average Interruption Frequency Index (SAIFI) of 1.41 in 2016 was substantially below the target of 2.32. Consistent with SAIDI, there are ongoing efforts to improve reliability including replacing aging infrastructure and improving vegetation management.

PUC's target for SAIFI in 2018 is lower than the OEB Distributor target (fixed five year average (2012 – 2016)) of 1.52.

3.2.3 Asset Management

Distribution System Plan Implementation Progress

Although PUC has employed distribution system planning for several years, the OEB instituted a mandatory requirement for this activity to be practised provincially, along with associated performance measures, beginning in 2013. We expect that implementation of this standardised approach will allow us to strengthen our commitment to responsible long term planning and sustainable asset management and to align our objectives with those of the of the OEB ultimately maximising benefit to our ratepayers.

All distributors are required to file a Distribution System Plan (DSP) when filing a cost of service application for the rebasing of their rates. PUC is presently engaged in migrating and expanding upon its existing distribution system planning to create a formal DSP that meets all OEB requirements. The new DSP will be accompanied by performance measures and once completed will be filed with PUC's next OEB rate application to be filed in 2017.

3.2.4 Cost Control

Efficiency Assessment

The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC (PEG) on behalf of the OEB to produce a single efficiency ranking. The PEG econometrics model attempts to standardize costs to facilitate more accurate cost comparisons among distributors by accounting for differences such as number of customers, treatment of high and low voltage costs, kWh deliveries, capacity, customer growth, length of lines, etc. All Ontario electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual costs versus the PEG model predicted costs.

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The following table summarizes the distribution of all distributors across the 5 groupings for 2016:

Group	Demarcation Points for Relative Cost Performance	Group Ranking	# of Ontario LDCs in Group
1	Actual costs are 25% or more below predicted costs	Most Efficient	6
2	Actual costs are 10% to 25% below predicted costs	More Efficient	14
3	Actual costs are within +/-10% of predicted costs	Average Efficiency	32
4	Actual costs are 10% to 25% above predicted costs	Less Efficient	13
5	Actual costs are 25% or more above predicted costs	Least Efficient	3

In 2016, for the fourth year in a row, PUC Distribution was placed in Group 4. PUC Distribution's efficiency performance based on the PEG model was over the predicted costs by 14% in 2016 compared to 16.2% in 2015.

Included in PUC's operating, maintenance and administrative expenses is a charge from PUC Services that is based on depreciating and financing of the vehicles, tools, computer equipment, office equipment etc. that is utilized to provide services to PUC. For utilities that own the vehicles and equipment to service their customers, these expenses are included in depreciation and financing costs. As the total costs would be the same, removing the depreciation and financing costs from PUC's operating costs would better align costs comparisons in the PEG model with other utilities. In addition, PUC has been including property taxes in account 5675 – Maintenance of General Plant. Commencing in 2017, PUC will be recording these expenses in account 6105 - Taxes Other Than Income

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Taxes which is not included in the PEG calculation. Projections for 2017 indicate that PUC would be in Group 3 after removing the non-operating type costs from the PEG calculation. PUC's efficiency ranking remains in Group 3 in 2018 through to the end of the projection period in 2021 with the removal of the non-operating costs from the calculation.

PUC's target for 2018 is to improve efficiency performance in order to be rated as a Group 3 utility after the removal of the non-operating costs from the PEG calculation.

Total Cost per Customer

Total cost per customer is calculated as the sum of PUC Distribution's capital and operating costs, including certain adjustments to make the costs more comparable between distributors (i.e. under the PEG econometrics model), and dividing this cost figure by the total number of customers that PUC Distribution serves. The cost performance result for 2016 is $695 per customer which is a 0.57 % decrease over 2015. Overall, the company's Total Cost per Customer has increased on average by 3.26% per annum over the period 2012 through 2016. For the period of 2013 to 2016, the Total Cost per Customer has increased by approximately 0.40% per year. PUC Distribution will continue to replace aging distribution assets proactively in a manner that balances system risks and customer rate impacts. PUC Distribution's capital and operating programs will be further defined in its 2018 rate application to be filed in 2017. The company continues to implement productivity and improvement initiatives to help offset some of the costs associated with future system improvement and enhancements. Customer engagement initiatives that commenced in 2016 will continue in order to ensure customers have an opportunity to share their viewpoint on PUC Distribution's capital spending plans.

PUC's target for this metric in 2018 is $660 excluding the non-operating costs discussed above.

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 the company operates to serve its customers. PUC Distribution's 2016 rate is $31,314 per Km of line, a 0.20% decrease over 2015.

PUC Distribution continues to experience a low level of growth in its total kilometers of lines due to a low annual customer growth rate. Such a low growth rate has reduced the

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ability to fund capital renewal and increasing operating costs through customer growth. As a result, total cost per Km of line has increased an average of 3.45% since 2012 with the increase in capital and operating costs. For the period of 2013 to 2016, the Total Cost per Km of Line has increased by approximately 0.40% per year.

PUC's target for this metric in 2018 is $29,904 excluding the non-operating costs discussed above.

3.3 Public Policy and Responsiveness

3.3.1 Conservation and Demand Management

Net Cumulative Energy Savings

PUC is committed to helping its customers understand their energy usage by offering programs that enable them to become more energy efficient. PUC has a conservation target of 26.4 Gigawatt hours by the end of 2020. Results for 2016 show progress of 52.97% towards that target.

This achievement was made possible by the strong participation by local commercial/industrial customers in retrofit and auditing programs. Residential customers also participated in saveONenergy coupon events opting to replace lights in their homes to more energy efficient ones, as well as purchasing other energy efficient equipment. The combined efforts of participants from both the residential and business sectors made the achievement of substantial energy savings possible. Notable projects were the city wide conversion of streetlights from HPS to LED, not only in Sault Ste. Marie but Prince Township and Batchewana First Nations. Municipal parking lots followed suit with upgrading their parking lot lighting to LED, while small businesses began changing their florescent lamps and incandescent bulbs to efficient LED tubes and lamps. PUC remains committed to providing its customers with cost effective conservation programs to help them save electricity and lower their electricity bills. PUC will continue to innovate new ways to promote and support customers in reducing their consumption today and for the future.

As a member of CustomerFirst, PUC is part of a joint Conservation (CDM) Plan that has been approved by the IESO. The joint plan will achieve 141,877 MWh of savings which is equal to the combined targets that were allocated to each CustomerFirst member under

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the new framework. Through the CustomerFirst joint CDM Plan, PUC will continue to work collaboratively with the other CustomerFirst utilities to find efficiencies and reduce costs. The group will be sharing resources and working together in all areas of CDM including sales, marketing, customer and project support to provide value to ratepayers.

PUC's target for this metric in 2018 is 4,651.8 mWhs.

3.3.2 Connection of Renewal 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 for their project from the Electrical Safety Authority. For the year 2016 four CIA requests were received for a total of 820kW of FIT generation, and all applications were processed within the prescribed timelines.

PUC's target for this metric in 2018 is to complete all assessments within the prescribed timelines.

New Micro-embedded Generation Facilities Connected On Time
In 2016, interest in the micoFIT program was much lower than in previous years. PUC Distribution Inc. received only one application and provided an offer to connect, but no follow-up request for connection was received. Outside of the micoFIT program, one application for a net metering load displacement installation was made. PUC's process to connect these projects is very streamlined and transparent for its customers. PUC works closely with customers and contractors to address any connection issues and ensure projects are connected in a timely manner.

With the termination of IESO's microfit program PUC is not certain what level of customer interest will materialize under the new net metering program structure. In any event, PUC's target for this metric in 2018 is to connect net-metered generation facilities within 5 business days of all service connection requirements being met.

3.4 Financial Performance

3.4.1 Financial Ratios

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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. PUC Distribution's current ratio has increased from 0.90 in 2015 to 1.52 in 2016. By increasing over 1, PUC Distribution is in a good position to cover the company's short-term debts and financial obligations.

PUC's target for this metric in 2018 is to maintain the current ratio above 1.

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. PUC Distribution has a debt to equity structure of 70% to 30% that approximates the deemed 60% to 40% capital mix as set out by the OEB – this translates to a 2016 debt to equity ratio of 2.34. PUC Distribution's long range plan is to push the debt to equity towards the 60/40 level.

PUC's target for this metric in 2018 is to reduce the debt to equity to 67%/33%.

Profitability: Regulatory Return on Equity – Deemed (included in rates)

PUC Distribution's current distribution rates were approved by the OEB and include an expected (deemed) regulatory return on equity of 8.98%. The OEB allows a distributor to earn within +/- 3 percentage points 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

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PUC Distribution's return on equity in 2016 at 0.98% was more than 3 percentage points lower than the expected return of 8.98%. The variance in return on equity is the result of PUC Distribution's OM&A expenses in 2016 being approximately $1.4 million higher than included in the approved 2013 cost of service rate application. In addition, PUC did not increase its rates in one year of the current IRM rate period and postponed its Cost of Service rate application due to the local economic circumstances. PUC plans on filing a 2018 Cost of Service Rate Application for rates effective in 2018.

PUC's target for this metric is a regulatory rate of return equal to the deemed ROE.

4. ANALYSIS OF PUC's BUSINESS PLAN

The Business Plan provides for prudent and sustainable investment in core business operations. The achievement of this plan is subject to obtaining approval for rates in 2018 as requested and to business risks as noted above. Following is a summary of the five year financial plan that is attached in Appendix A:

$ MM	2017 Budget	2018 Budget	2019 Projected	2020 Projected	2021 Projected
Net Income	$0.5	$1.6	$2.7	$2.7	$2.7
OM&A Expenses	$11.49	$11.95	$12.14	$12.32	$12.50
Capital Expenditures*	$4.7	$5.4	$8.6	$5.4	$6.2
Return on Equity	3.48%	5.75%	8.02%	7.63%	7.41%
Debt to Equity %	69/31	67/33	66/34	64/36	61/39
Working Capital (# of days)	18	13	13	12	10

*Net of capital contributions, 2019 includes replacement of distribution station

Net income increases in 2018 as a result of the revenue increase associated with rate rebasing. The 2018 budget includes only a portion of the increase as it is anticipated that the rate increase will take place in the second half of 2018. Net income increases again in

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2019 as the rebased rates will be effective for the entire year.

The replacement of an additional substation is planned for 2022.

Debt to equity declines to the target of 60/40 by 2022 and declines in subsequent years.

Working capital remains at a low level through the projection period. PUC did not receive approval for the full amount requested in rates for OM&A expenses in its last cost of service rate application in 2013. Although efforts in improving efficiency have resulted in some positive results, due to increased regulatory requirements, costs deemed necessary to service customers and the need to replace infrastructure, PUC's expenditures were above those included in rates throughout the next five years. This has resulted in a decrease in the company's working capital. PUC's challenge is to continue to provide service to customers in the regulated rate environment where revenue increases are capped at less than inflation and ever-evolving regulations increase operating expenses in a local economy that is not expanding. An increase in working capital can be attained through lower capital expenditures or lower payments to the shareholder. At some point in this five year period, the shareholder will be approached to discuss refinancing options to improve cash flow.

Despite the moderate rate increases expected in the IRM years, management believes that it can deliver PUC's capital plan and manage costs effectively and in a manner that continues to deliver quality distribution service safely and reliably for ratepayers. The Business Plan reflects managed increases in expenditures with due regard for the following:

- Expectations set by the OEB regarding the nature and magnitude of expenditures.
- Prioritization of investments in the context of requirements for distribution system renewal and the needs of PUC's ratepayers.
- Advancement of business processes through replacement or new investments in information technology systems and technology-based processes.
- Continued improvement to customer engagement and communication.
- Customer affordability.
- A reasonable rate of return for the shareholder.

5. FINANCIAL RESULTS

5.1 Recognition of Regulatory Assets and Liabilities

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International Financial Reporting Standards (IFRS) does not permit the recognition of regulatory assets and liabilities. Under IFRS, PUC is no longer permitted to record regulatory assets and liabilities on its balance sheet and, as a result, s ettlement differences for non-distribution charges (energy, transmission, wholesale market service charge, etc.) are recorded as net earnings or net costs depending on whether the settlement difference is positive or negative in the period. These settlement differences will be collected/returned to customers in a future period and are not predictable nor can they be readily forecasted / budgeted. Therefore, settlement differences have not been included in budgeted operating revenues/expenses.

5.2 Conservation and Demand Management (CDM)

A condition of its Distribution Licence, PUC is mandated to achieve a targeted level of energy savings. As a member of CustomerFirst, PUC is part of a joint Conservation (CDM) Plan that has been approved by the IESO. Through the CustomerFirst joint CDM Plan, PUC will continue to work collaboratively with the other CustomerFirst utilities to find efficiencies and reduce costs. The group will be sharing resources and working together in all areas of CDM including sales, marketing, customer and project support to provide value to ratepayers. CDM programs are solely funded from the Global Adjustment Mechanism and, therefore, do not affect revenues or operating expenses reflected in this Business Plan.

5.3 Revenue

2017 revenue is based on the 2017 budget less year to date actual results which are approximately 3% or $500,000 under budget. 2018 revenue includes the cost of service rate increase. The full effect of the cost of service rate application occurs in 2019, with IRM increases of 1.5% included in revenue in 2019, 2020 and 2021.

5.4 Operating, Maintenance and Administrative Expenses

OM&A expenses reflect costs required to operate, maintain and sustain the electricity distribution operations, including new expenditures to address regulatory changes.

PUC's OM&A expenditures have increased from $9.78 million in 2012 to the 2018 rate request amount of $11.96 million, an average annual increase of 3.4%.

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PUC's OM&A request for the 2013 CoS rate application was $10.93, however this amount was reduced through the settlement process to the approved amount of $9.95.

Although PUC did not receive approval for the full amount requested in rates for OM&A expenses in its last cost of service rate application in 2013, due to increased regulatory requirements and costs deemed necessary to service customers, PUC's expenditures were $11.2 million compared to the approved amount in rates of $9.95 million.

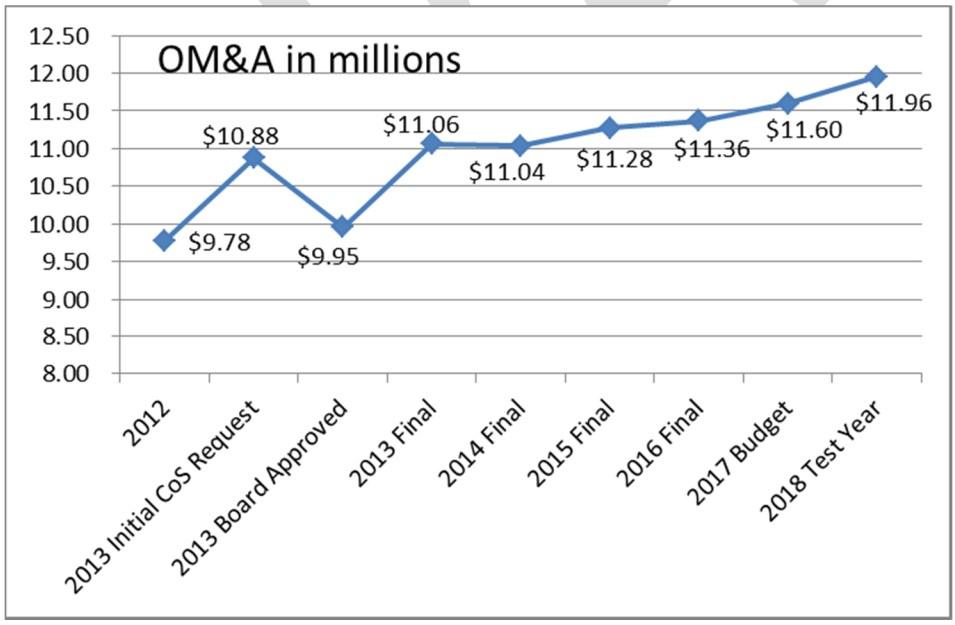
The increase of $1.28 million from 2012 to 2013 is in the following areas. For comparison purposes the 2012 expenses have been reduced by the regulatory smart meter entry that pertains to prior year costs. Also, for comparison purposes, the 2013 expenses have been reduced by the increased amount ($1,141,376) included in miscellaneous revenue which offsets the new shared corporate headquarter cost.

Area	Amount	
Labour	$444,000	Line and Engineering Dept. labour for capital projects was high in 2012 which required the delay in operating and maintence programs that were resumed in 2013 (Line $298k, Engineering $88k), Meter Dept. labour was temporarily redirected to the smart meter project in 2012 but resumed regular operating and maintenance programs in 2013 ($72k)
Management Labour	$248,000	Engineering P&C Engineer not filled for full year in 2012 but was filled in 2013, higher level of capital effort in 2012 for smart meters, etc.
Line clearing	$188,000	2012 was a low year for line clearing costs – was highly dependent on area to be cleared and number of contractors bidding – line clearing areas were revised in 2016 to a more consistent annual area and program moved from 3 years to 4 years
Bad Debts	$74,000	Increased cost of energy to customers has increased the amount of customers' bills –

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		number of write-offs (w/o) and amounts per w/o are higher
New Building Operating expenses – property taxes	$244,000	New building occupied in 2013 – resulted in higher property taxes
New Building Operating expenses – other operating expenses	$117,000	New building occupied in 2013 – resulted in higher operating costs – utilities, janitor, etc.
Misc.	-$105,000	Various non-material changes
	$1,210,000	

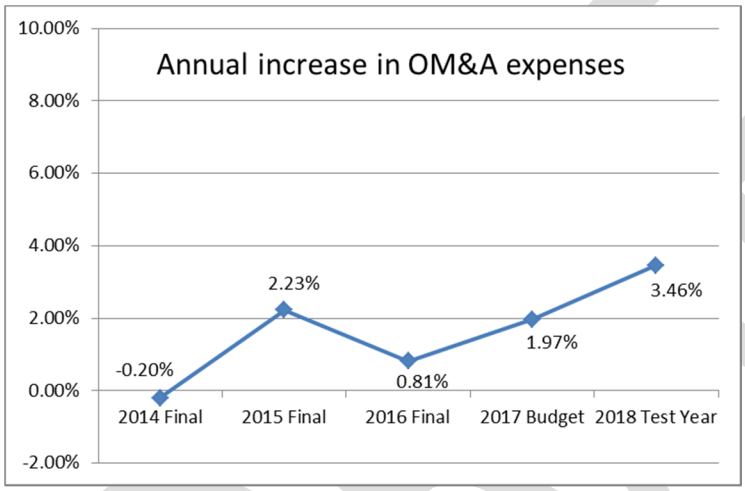
OM&A expenses have increased from $11.02 million in 2013 to $11.96 million in the 2018 test year request to be submitted to the OEB for approval. This equates to an average annual increase of 1.6%. Despite regulatory pressures, the average annual increase over the 2013 to 2018 period has been below the rate of inflation.



The year over year percentage increases are indicated in the chart below. PUC is requesting the following items in its Cost of Service rate application which are not currently in expenses being recovered in rates:

- Increased cost for the mandated PCB transformer testing,
- Increased cost for the mandated MIST meter conversion,
- Additional staff resources to address the increased and still increasing regulatory burden, and
- Additional costs for the Distribution/Transmission station maintenance program to be compliant with new Independent Electricity System Operator (IESO) requirements for under-frequency load shedding scheme

With the items noted above, the increase from 2017 to 2018 in OM&A expenses requested is 3.5%, which as noted above is an average annual increase of 1.6% over 2013 levels.



5.5 Capital Expenditures

Capital investments are required to maintain adequate security of supply to meet customer needs, as well as to replace end-of-life assets. PUC has recently completed a Distribution System Plan (DSP) which includes an Asset Management Plan (AMP). The plan indicates the areas of the distribution system that should be the focus of resources in order to maintain reliable service to customers. Included in the 2019 capital expenditures is the replacement of a substation. Work on replacing an additional substation is scheduled to commence in 2021.

Historical Capital Expenditures

CATEGORY	2013	2014	2015	2016	2017
System Access	2,310,000	2,531,753	1,549,411	1,211,917	1,271,457
System Renewal	6,082,921	3,753,602	4,639,948	4,243,808	3,372,227
System Service	-	-	-	-	38,236
General Plant	2,028,344	375,693	66,532	82,630	-
TOTAL EXPENDITURE	10,421,265	6,661,048	6,255,891	5,538,355	4,681,920

Planned Capital Expenditures

CATEGORY	2017	2018	2019	2020	2021	2022
System Access	1,271,457	1,511,028	1,615,276	2,086,480	1,603,804	1,560,434
System Renewal	3,372,227	3,761,033	6,905,898	3,296,444	4,532,889	7,092,642
System Service	38,236	-	-	-	-	-
General Plant	-	86,294	54,629	61,932	59,853	55,100
TOTAL EXPENDITURE	4,681,920	5,358,355	8,575,803	5,444,856	6,196,546	8,708,176

5.6 Financing

No changes have been made to the current financial structure in this financial plan. Debt to equity, which includes shareholder debt, is currently 69% debt and 31% equity in comparison to the deemed debt to equity of 60/40. The payment to the shareholder remains at $1.62 million throughout the projection period. The financial plan results in a debt to equity level of 62/42 by 2021, falling to 60/40 by 2022.

6. CONCLUSIONS

PUC's 2017 to 2021 Business Plan presents a challenging financial picture for the company, balancing reliability and service to customers with affordability. All costs and projected revenues have been closely examined and reasonable assumptions respecting growth and

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expected OEB rate increases have been used.

The OEB's 4th Generation IRM framework will continue to challenge PUC's management to find operational savings and efficiencies throughout the organization in order to achieve reasonable financial results. Although a capital replacement plan is in place, ongoing monitoring of cash flow levels and updated asset condition assessments will necessitate constantly reviewing the plan as more information becomes available in order to balance reliability and affordability. In addition, steps will be taken toward restructuring the current debt with the shareholder (PUC Inc.) to take advantage of current low interest rates, reduce the current debt to equity structure and strengthen the company's balance sheet.

Management remains confident that with a successful outcome to the Cost of Service rate application and renegotiation of the current financial structure with the shareholder, the financial challenges will not hinder PUC's goals of exceeding the service quality indicators as detailed on the LDC scorecard, improve customer communication and advocacy, replace infrastructure in an effective and prudent manner, maintain rates at a reasonable level and provide a return to the shareholder.

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Appendix A

Pro Forma Financial Statements

PUC Distribution Inc.
Results of Operations

	For the Year Ending December 31				
	2017 Estimated	2018 Budget	2019 Projected	2020 Projected	2021 Projected
Revenue					
Net Electricity Distribution Revenue	$ 16,540,855	$ 18,243,934	$ 19,837,093	$ 20,134,649	$ 20,436,669
Other Revenue	$ 2,317,208	$ 2,249,978	$ 2,328,416	$ 2,342,054	$ 2,355,898
	$ 18,858,064	$ 20,493,912	$ 22,165,509	$ 22,476,704	$ 22,792,567
Expenses					
Operations	$ 5,796,432	$ 6,208,756	$ 6,301,887	$ 6,396,416	$ 6,492,362
Billing and Collecting	$ 2,273,198	$ 2,199,039	$ 2,232,024	$ 2,265,504	$ 2,299,487
Administrative	$ 3,376,922	$ 3,548,036	$ 3,601,257	$ 3,655,276	$ 3,710,105
Operating Expenses	$ 11,446,552	$ 11,955,831	$ 12,135,169	$ 12,317,196	$ 12,501,954
Depreciation	$ 3,663,582	$ 3,783,956	$ 3,917,915	$ 4,132,310	$ 4,268,431
Operating and Depreciation	$ 15,110,134	$ 15,739,787	$ 16,053,083	$ 16,449,506	$ 16,770,385
Income from Operating	$ 3,747,930	$ 4,754,126	$ 6,112,425	$ 6,027,198	$ 6,022,182
Interest Expense	$ 3,230,626	$ 3,172,092	$ 3,119,581	$ 3,194,857	$ 3,134,637
Income before taxes	$ 517,304	$ 1,582,034	$ 2,992,845	$ 2,832,341	$ 2,887,545
Income taxes	$ -	$ -	$ 244,054	$ 171,476	$ 167,029
Net Income	$ 517,304	$ 1,582,034	$ 2,748,790	$ 2,660,865	$ 2,720,516
Openning Retained Earnings	$ 7,830,504	$ 8,347,808	$ 9,929,841	$ 12,678,631	$ 15,339,497
Net Income	$ 517,304	$ 1,582,034	$ 2,748,790	$ 2,660,865	$ 2,720,516
Dividends	$ -	$ -	$ -	$ -	$ -
Closing Retained Earnings	$ 8,347,808	$ 9,929,841	$ 12,678,631	$ 15,339,497	$ 18,060,012

PUC Distribution Inc.
Balance Sheets

	For the Year Ending December 31				
	2017 Estimated	2018 Budget	2019 Projected	2020 Projected	2021 Projected
Assets					
Current Assets	$ 21,198,475	$ 19,959,395	$ 20,051,072	$ 19,965,540	$ 19,276,083
Future Taxes	$ 1,081,000	$ 1,081,000	$ 1,081,000	$ 1,081,000	$ 1,081,000
Net Fixed Assets	$ 90,431,565	$ 92,005,964	$ 96,663,853	$ 97,976,399	$ 99,904,514
Regulatory Assets	$ 1,088,439	$ 1,088,439	$ 1,088,439	$ 1,088,439	$ 1,088,439
	$ 113,799,479	$ 114,134,798	$ 118,884,363	$ 120,111,378	$ 121,350,036
Liabilities					
Current Liabilities	$ 16,173,162	$ 16,173,162	$ 16,173,162	$ 16,173,162	$ 16,173,162
Notes Payable	$ 62,750,847	$ 61,504,133	$ 63,504,908	$ 62,071,057	$ 60,589,200
Deferred Revenue	$ 1,847,591	$ 1,847,591	$ 1,847,591	$ 1,847,591	$ 1,847,591
Regulatory Liabilities	$ 4,617,969	$ 4,617,969	$ 4,617,969	$ 4,617,969	$ 4,617,969
	$ 85,389,569	$ 84,142,855	$ 86,143,630	$ 84,709,779	$ 83,227,922
Shareholder Equity					
Common Shares	$ 20,062,107	$ 20,062,107	$ 20,062,107	$ 20,062,107	$ 20,062,107
Retained Earnings	$ 8,347,803	$ 9,929,836	$ 12,678,627	$ 15,339,492	$ 18,060,008
	$ 28,409,910	$ 29,991,943	$ 32,740,734	$ 35,401,599	$ 38,122,115
Total Liabilities and Shareholder Equity	$ 113,799,479	$ 114,134,798	$ 118,884,364	$ 120,111,378	$ 121,350,036

PUC Distribution Inc.
Statement of Working Capital

	For the Year Ending December 31				
	2017 Estimated	2018 Budget	2019 Projected	2020 Projected	2021 Projected
Opening Working Capital	$ 6,700,941	$ 5,003,562	$ 3,764,482	$ 3,856,159	$ 3,770,627
Net Income	$ 517,304	$ 1,582,034	$ 2,748,790	$ 2,660,865	$ 2,720,516
Add Depreciation	$ 3,663,582	$ 3,783,956	$ 3,917,915	$ 4,132,310	$ 4,268,431
Less Net Capital Expenditures	$ 4,681,920	$ 5,358,355	$ 8,575,803	$ 5,444,856	$ 6,196,546
Add Loan Proceeds	$ -	$ -	$ 3,300,000	$ -	$ -
Less Principle Repayments	$ 1,196,344	$ 1,246,714	$ 1,299,225	$ 1,433,851	$ 1,481,857
Ending Working Capital	$ 5,003,562	$ 3,764,482	$ 3,856,159	$ 3,770,627	$ 3,081,171

APPENDIX 13

Certificate of Evidence

Certification of Evidence

I, Andrew Belsito, Rates & Regulatory Affairs Officer of PUC Distribution Inc., certify that the evidence filed is accurate, consistent, and complete to the best of my knowledge.

Andrew Belsito

Andrew Belsito, CPA, CMA

Rates & Regulatory Affairs Officer

I, Terry Greco, Vice President of Finance and Corporate Support of PUC Distribution Inc., certify that the evidence filed is accurate, consistent, and complete to the best of my knowledge.

T Greco

Terry Greco

Vice President of Finance and Corporate Support