PUC Distribution Inc.
EB-2017-0071
Filed: March 29, 2018

EXHIBIT 1:

ADMINISTRATIVE DOCUMENTS

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Application

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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

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[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.

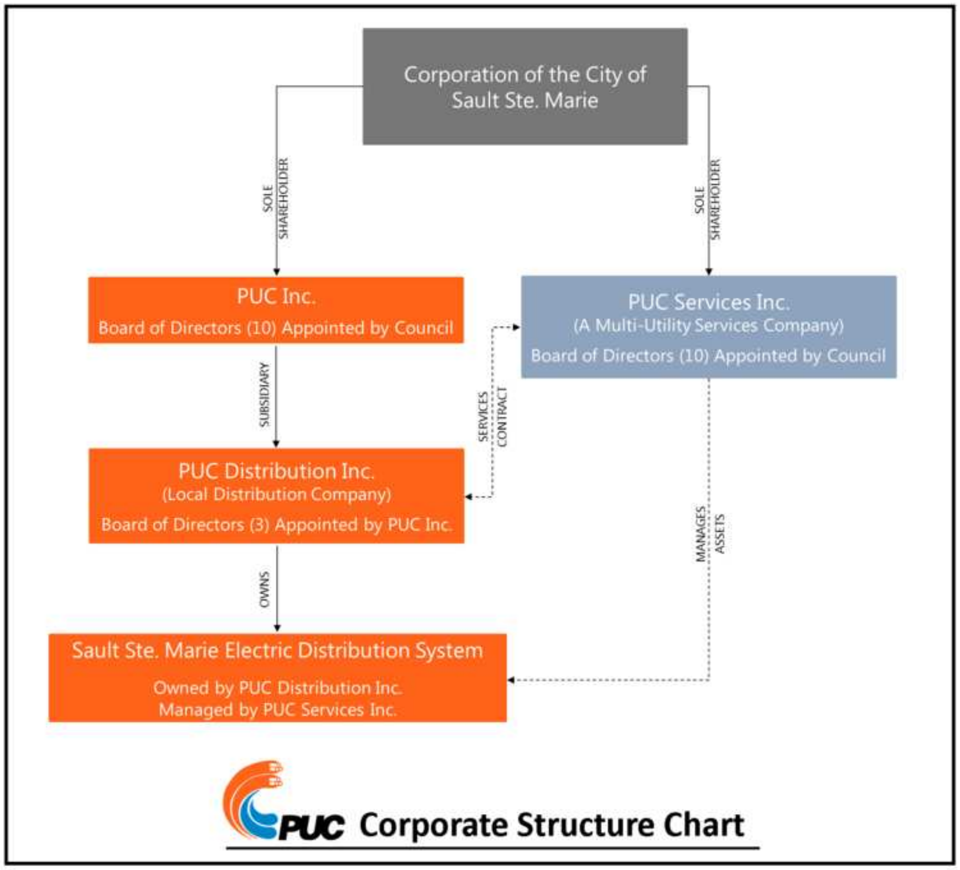
The fees paid by PUC Distribution Inc. to PUC Services Inc. are determined annually, in compliance with the Affiliate Relationships Code. See Management Services Agreement attached as Appendix 1.

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]

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[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]

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[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

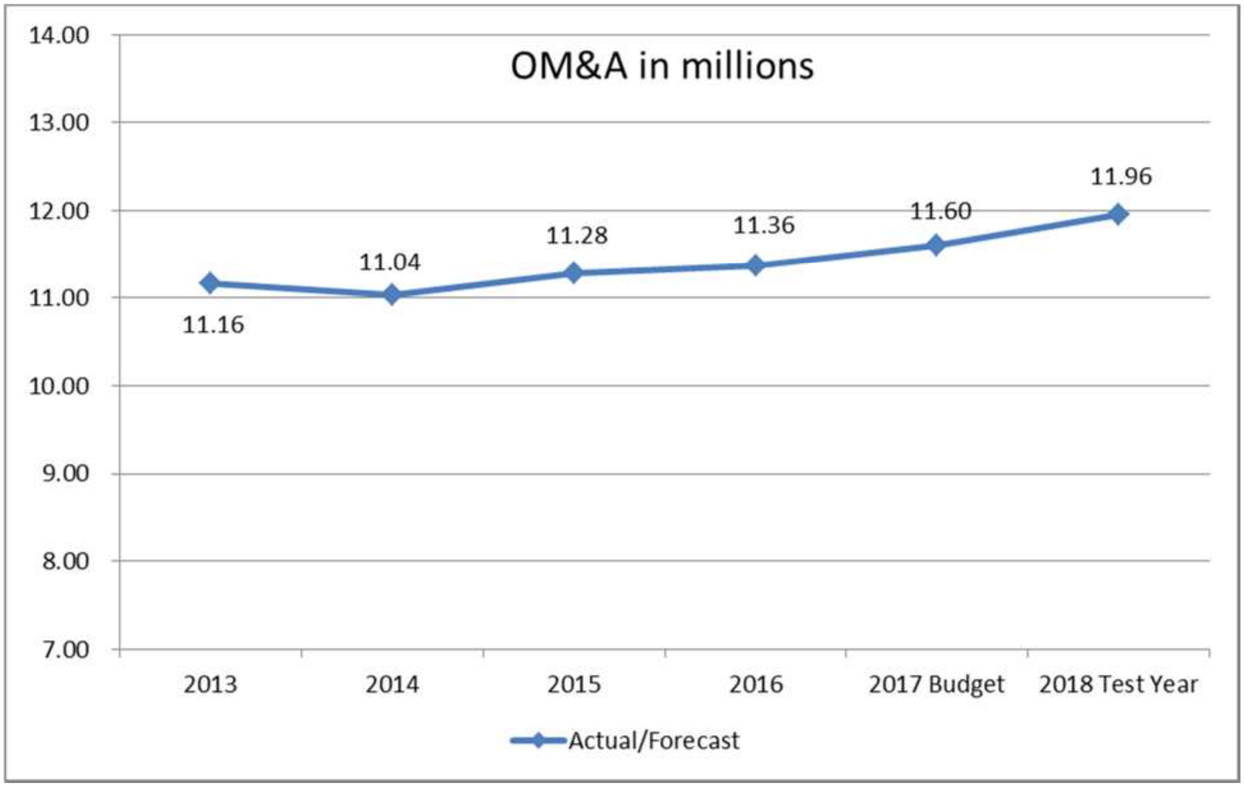
– property taxes		
New Building Operating expenses – other operating expenses	$117,000	New building occupied in 2013 – resulted in higher operating costs – utilities, janitor, etc.
Misc.	($105,000)	Various non-material changes
	$1,210,000	

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.

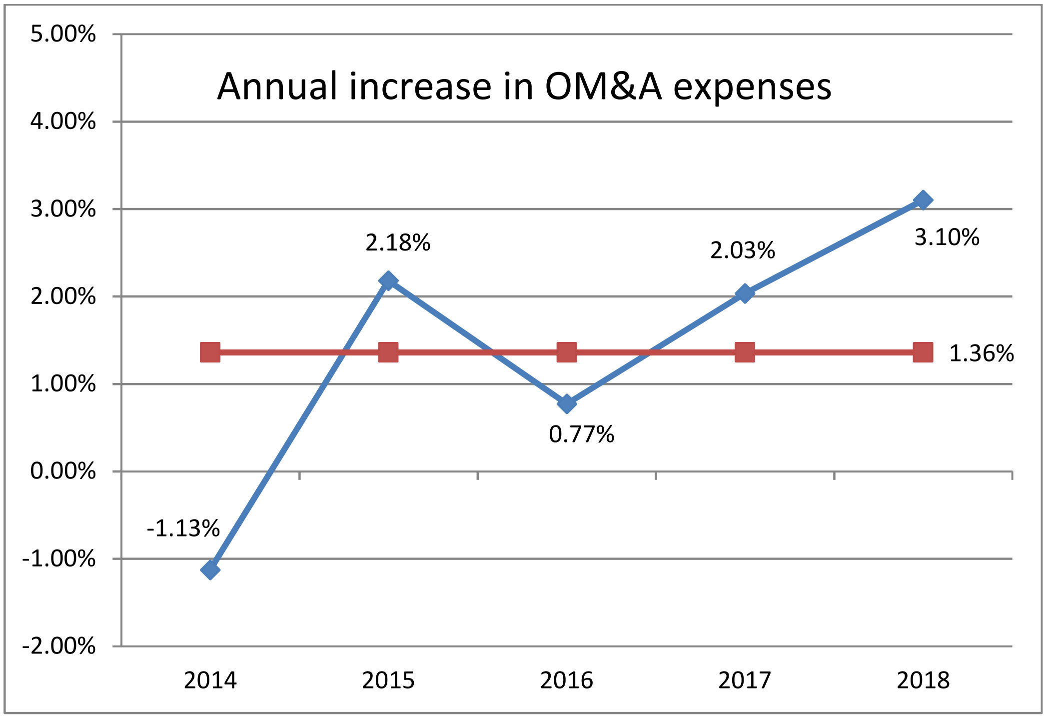
OM&A expenses have increased from $11.02 million in 2013 to $11.96 million in the 2018 test year request for this Application. This equates to an average annual increase of 1.6%. Despite regulatory pressures, the average annual increase over the 2013 to 2018 period has been below the rate of inflation.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

Rate Class	Monthly Service Charge 2017 Current	Monthly Service Charge 2018 Proposed	Monthly Service Charge % Difference	Unit of Measure	Distribution Volumetric Charge incl Transformer Allowance 2017 Current	Distribution Volumetric Charge incl Transformer Allowance 2018 Proposed	Distribution Volumetric Charge incl Transformer Allowance % 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.

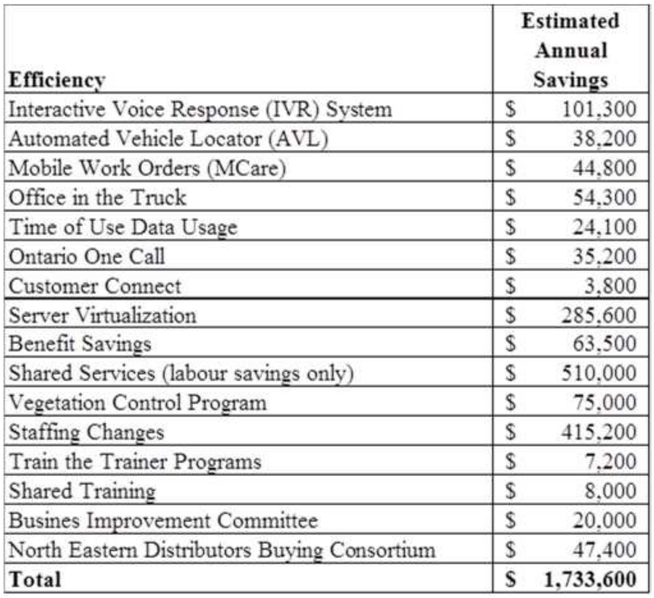
PUC Distribution has worked to balance the infrastructure and affordability drivers with a proposed rate increase that will affect the total average (using 750kWh) residential electricity bill, by less than $2.00/month.

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

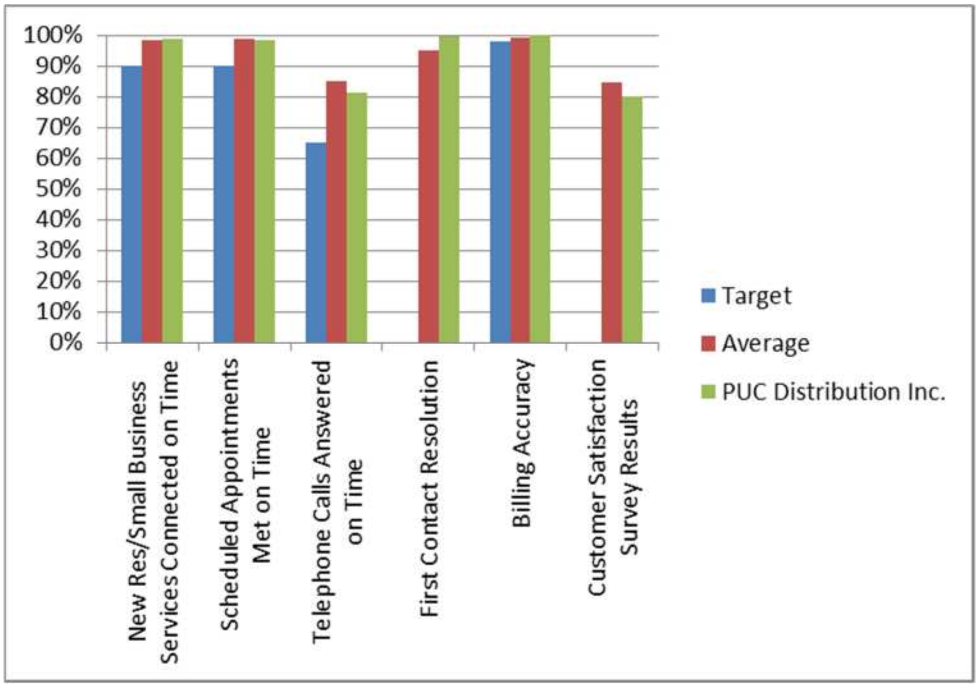
PUC Distribution engaged the UtilityPulse Division of Simul Corporation to conduct our 2015 and 2016 customer satisfaction survey. The survey is attached as Appendix 5. The UtilityPulse Electric Utility Survey is in its 19th year of annual surveys and is used by a significant number of Ontario distributors. 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.

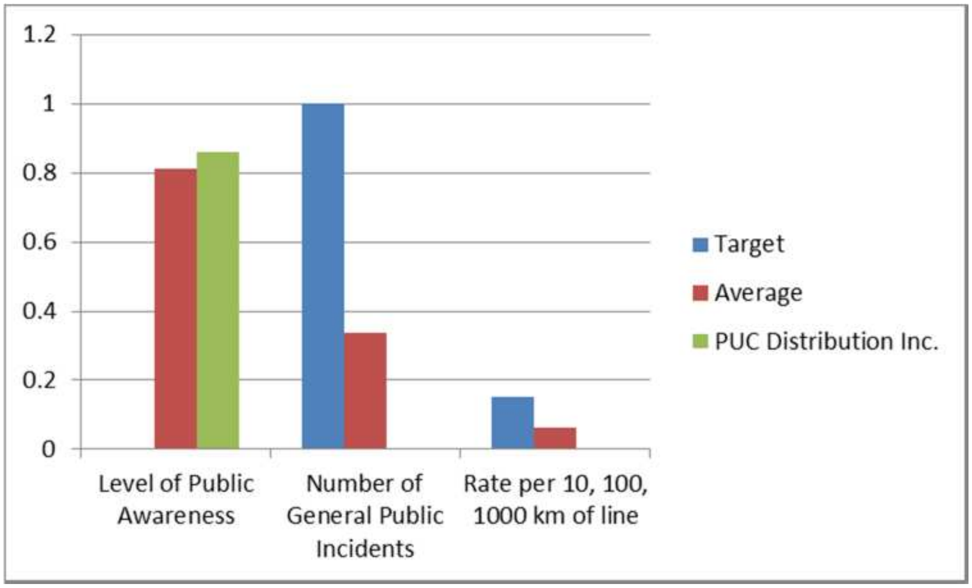
PUC Distribution's target for this metric in 2018 is to have zero (0) serious electrical incidents reported. This is more aggressive than the OEB scorecard target of 1. In PUC Distribution's view, 1 serious electrical incident is 1 too many. Management has its internal target accordingly.

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)

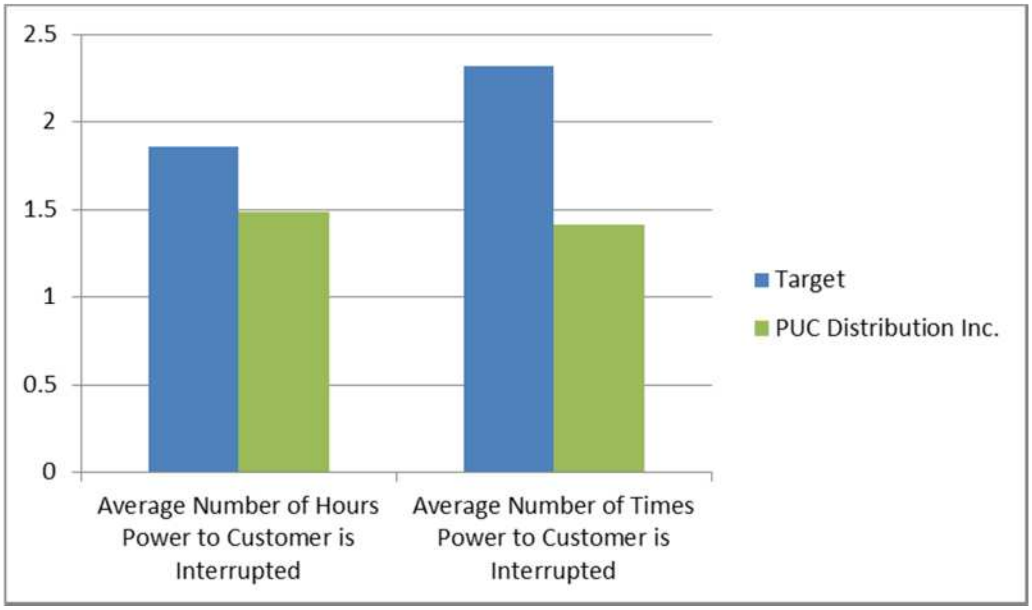
The System Average Interruption Frequency Index ("SAIFI") of 1.41 in 2016 was substantially below the target of 2.32. Consistent with SAIDI, there are ongoing efforts to improve reliability including replacing aging infrastructure and improving vegetation management.

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

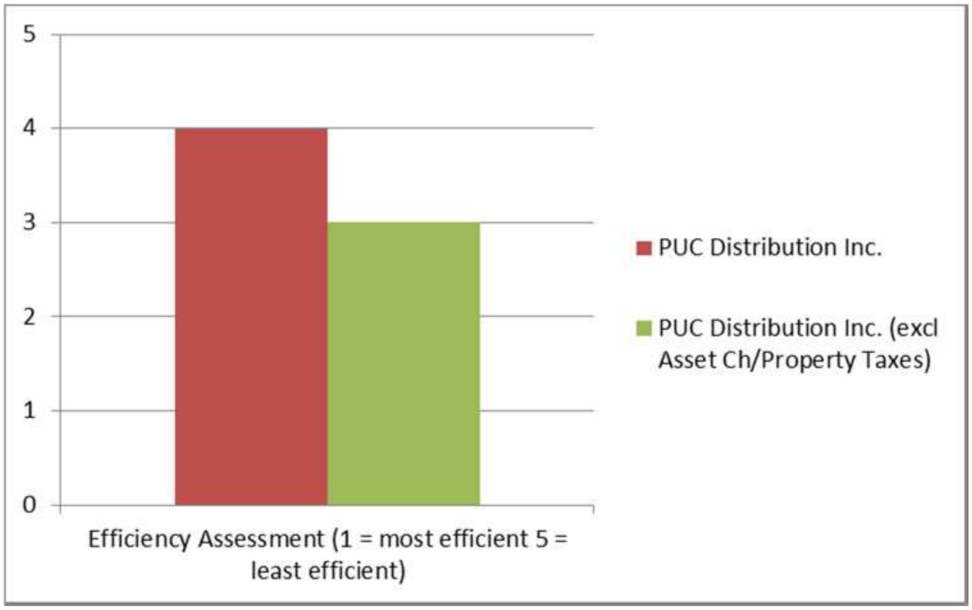
Total cost per customer is calculated as the sum of PUC Distribution's capital and operating costs, including certain adjustments to make the costs more comparable between distributors (i.e. under the PEG econometrics model), and dividing this cost figure by the total number of customers that PUC Distribution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

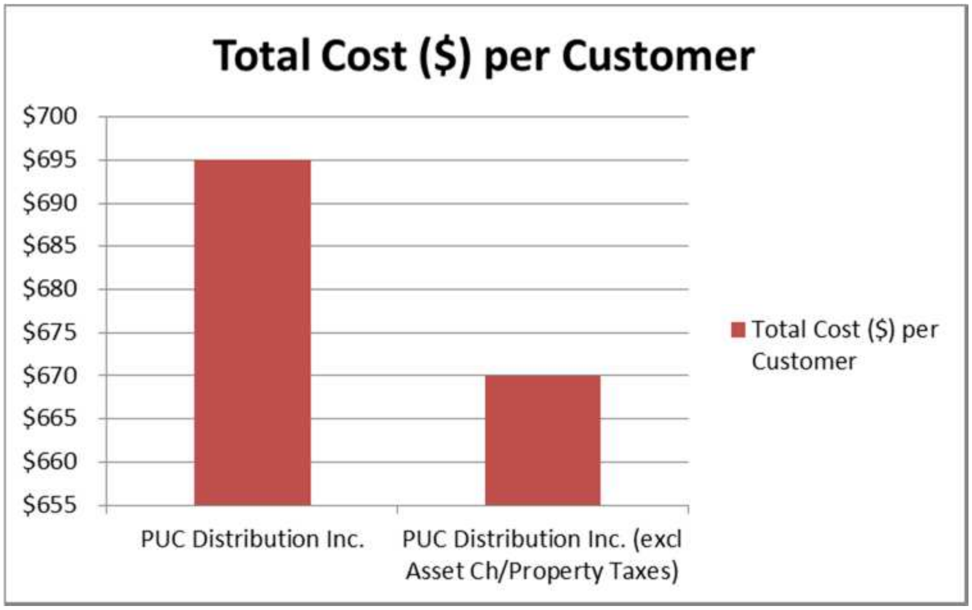
As indicated, PUC Distribution's efficiency rating in 2016 placed it in Group 4, compared to the provincial average of 3. However with the removal of the non-operating costs as detailed above, PUC Distribution has a cost per customer within 10% of predicted cost and would be placed in Group 3.

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.

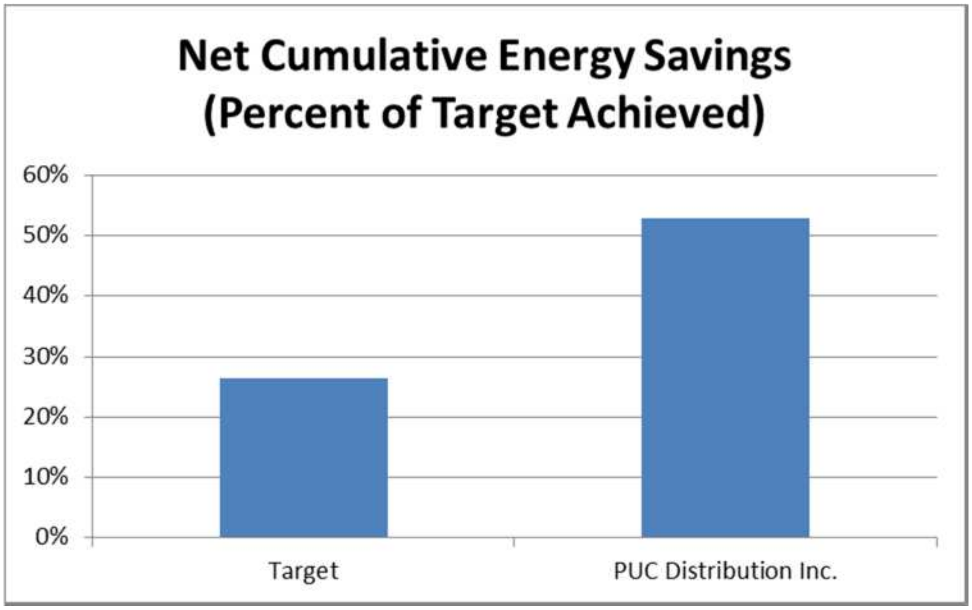
Net Cumulative Energy Savings (Percent of Target Achieved)

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

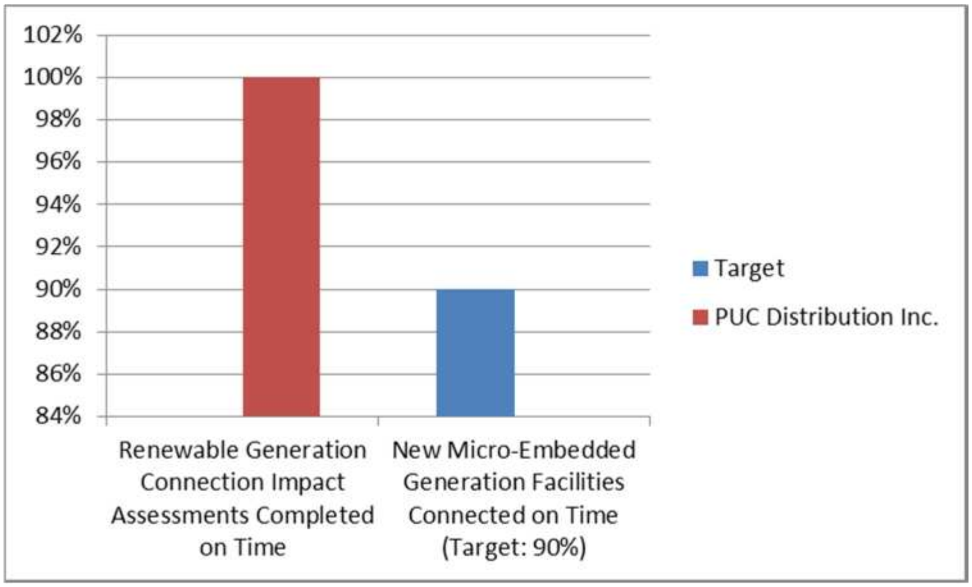
In 2014, PUC Distribution connected 7 new micro-embedded generation facilities 100% of the time within the prescribed time frame of 5 business days. In 2015, PUC Distribution connected 6 new micro-embedded generation facilities of which all were connected within the prescribed timeframe. In 2016, interest 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.

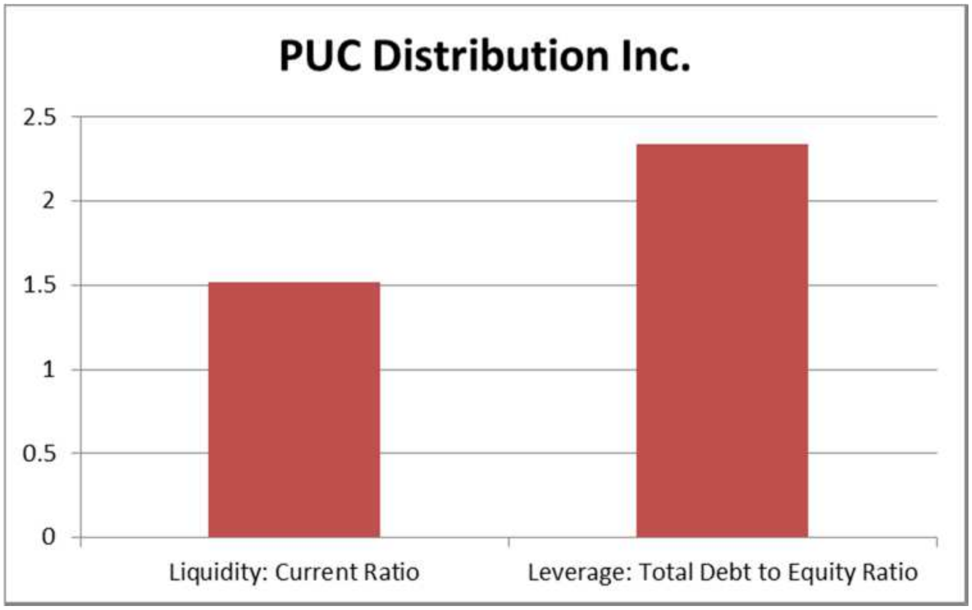
PUC Distribution's target for this metric is a regulatory rate of return equal to the deemed ROE.

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.

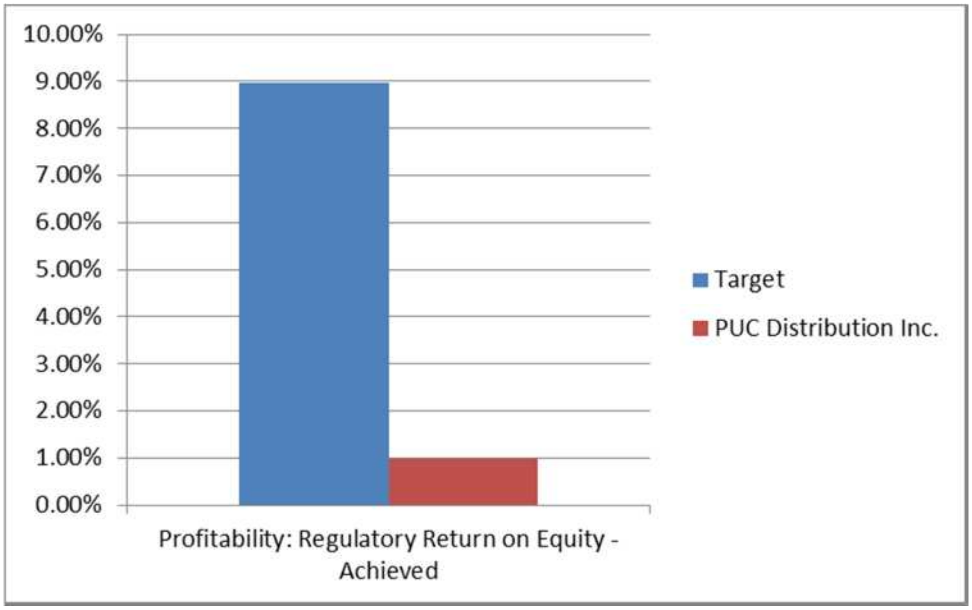
PUC Distribution's debt to equity ratio is well above the provincial average. As noted above and in PUC Distribution's business plan, PUC Distribution intends to reduce the debt to equity ratio. Steps will be taken toward reducing the current debt with the shareholder to take advantage of current low 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**	
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Add additional scenarios if required								

Table 2

	RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	Sub-Total						Total
			A		B		C		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	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.

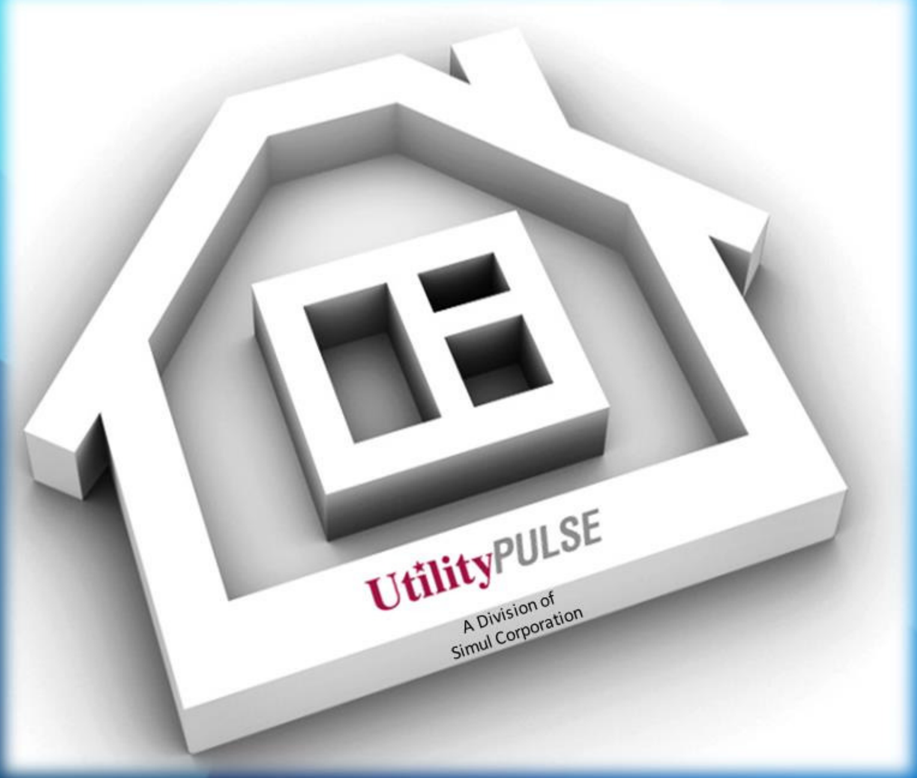
APPENDIX 5

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%

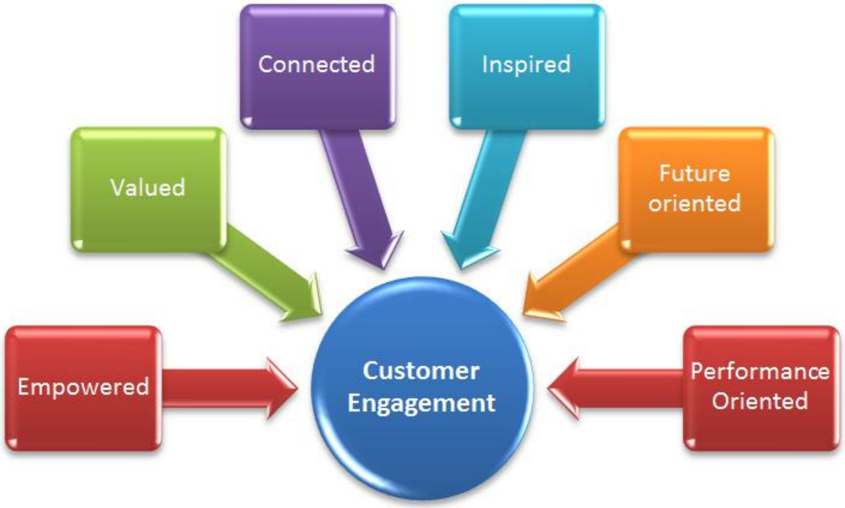
“Keeps its promises to customers and the community…”

Base: total respondents

CCEI: Customer Centric Engagement Index

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

Base: total respondents



Connected

Inspired

Valued

Future oriented

Empowered

Customer Engagement

Performance Oriented

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?*

"CEPr: Customer experience rating..."

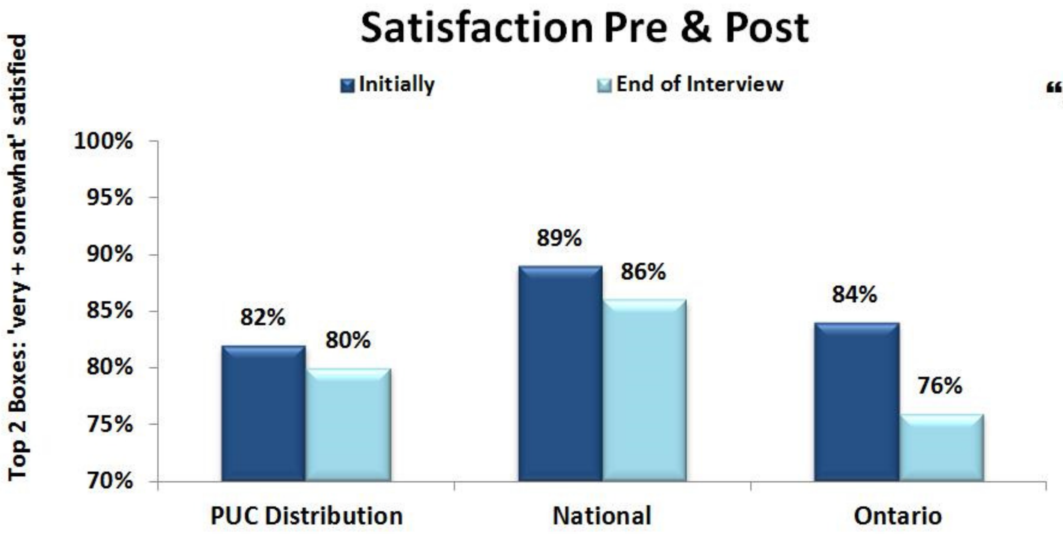
Customer Satisfaction

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

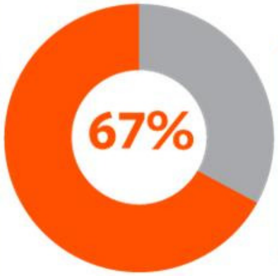
"Is a company that you would like to continue to do business with"

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

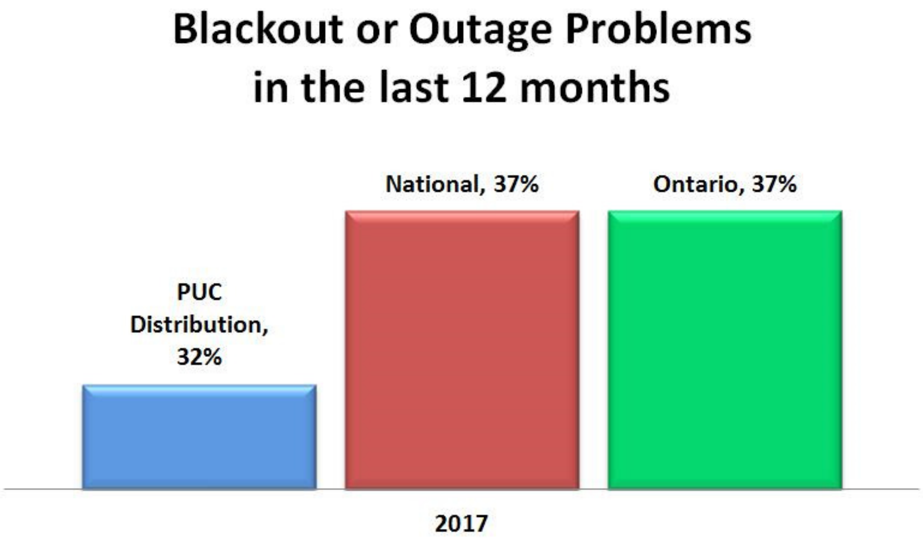
	PUC Distribution	National	Ontario
Top 2 Boxes: 'Definitely + Probably' recommend	67%	71%	59%

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



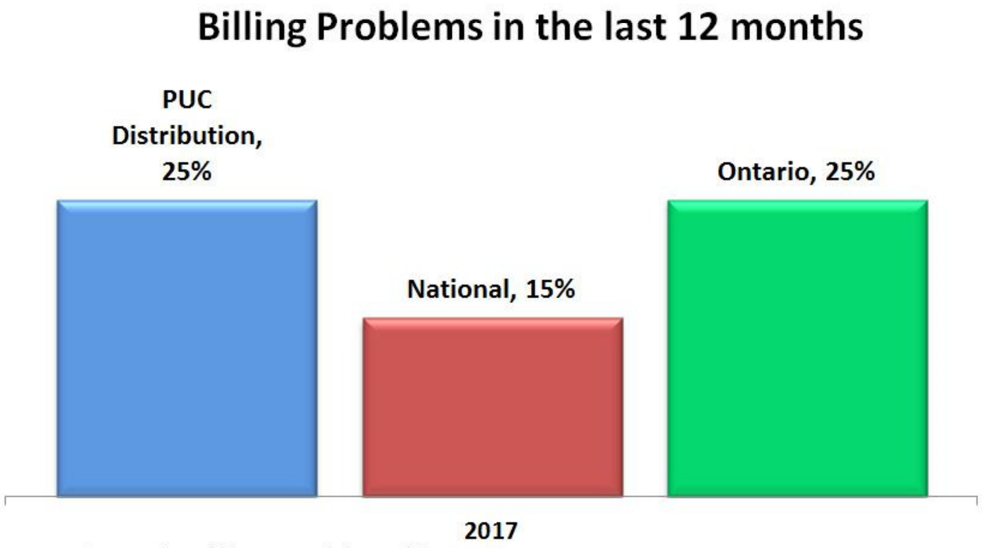
Base: total respondents/ (-) not a participant of the survey year

"... 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

81%

"... Provides accurate billing..."

Types of billing problems

Types of Billing Problems

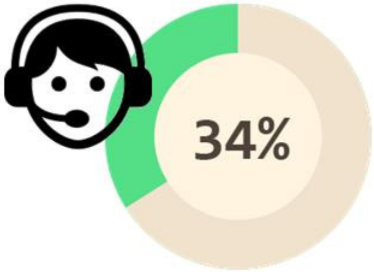
	PUC Distribution
The amount owed was too high	91%
Complaint about rates or charges	10%
The bill was difficult to understand	6%
Too many extra charges	4%
Payment incorrectly recorded	3%
Double payment	2%
The bill arrived late	1%
Wrong information on bill	1%

Base: total respondents with billing problems

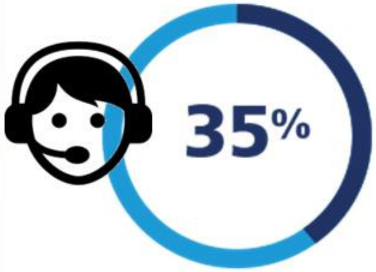
91%

"... 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.



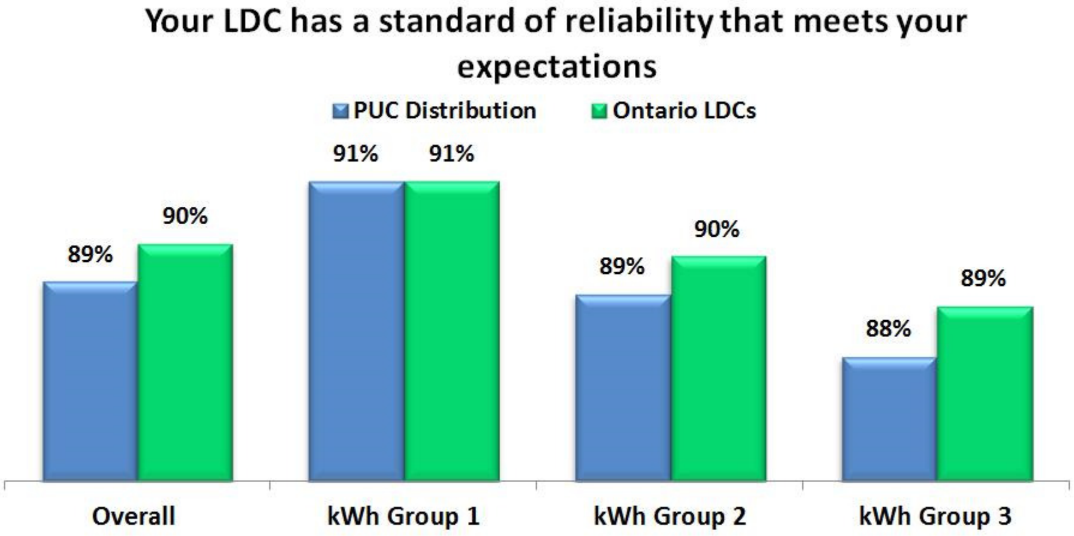
35% of PUC Distribution respondents with a billing problem did contact the utility.

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%

- Responding to the power outage

94%

- Restoring power quickly

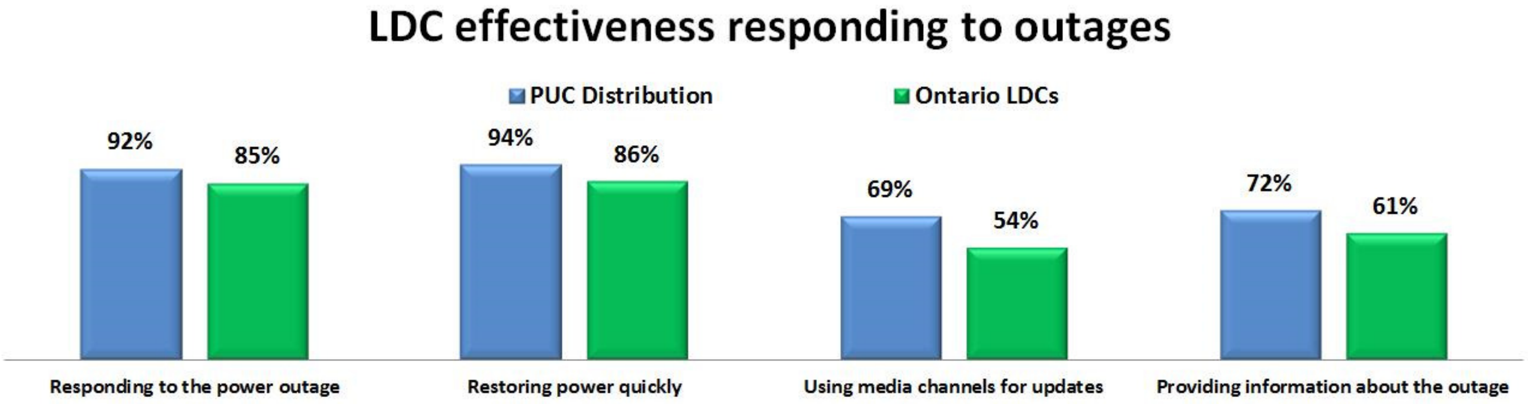
69%

- Using media channels for updates

72%

- 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

85%

"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%	55%	71%	53%
• Access the internet for information	• Have a social media account	• Use online banking	• 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%

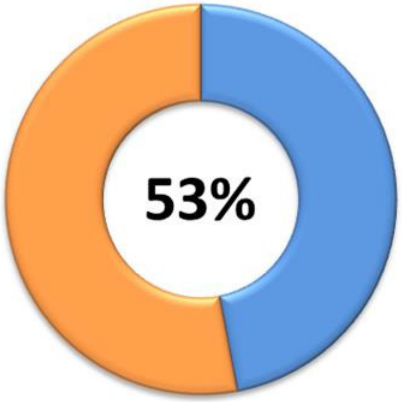
Base: total respondents / total respondents from the 2017 UtilityPULSE Database

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

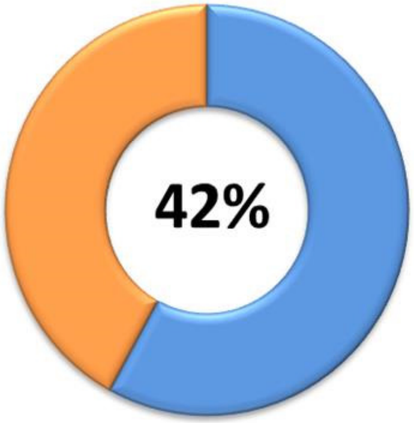
'Customers are well served by the electricity system in Ontario' – do you agree?

	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

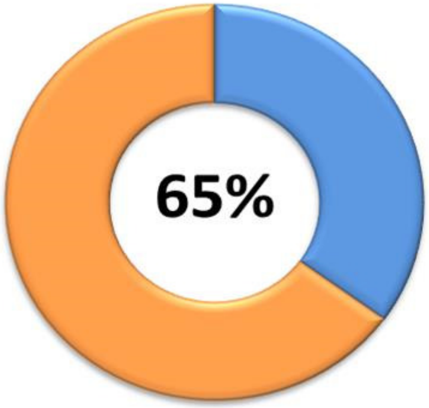
'Customer are confident in the electricity industry's ability to meet future expectations regarding quality, reliability and price' – do you agree?

	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

5%

Extremely knowledgeable

10%

Very knowledgeable

49%

Moderately knowledgeable

23%

Slightly knowledgeable

11%

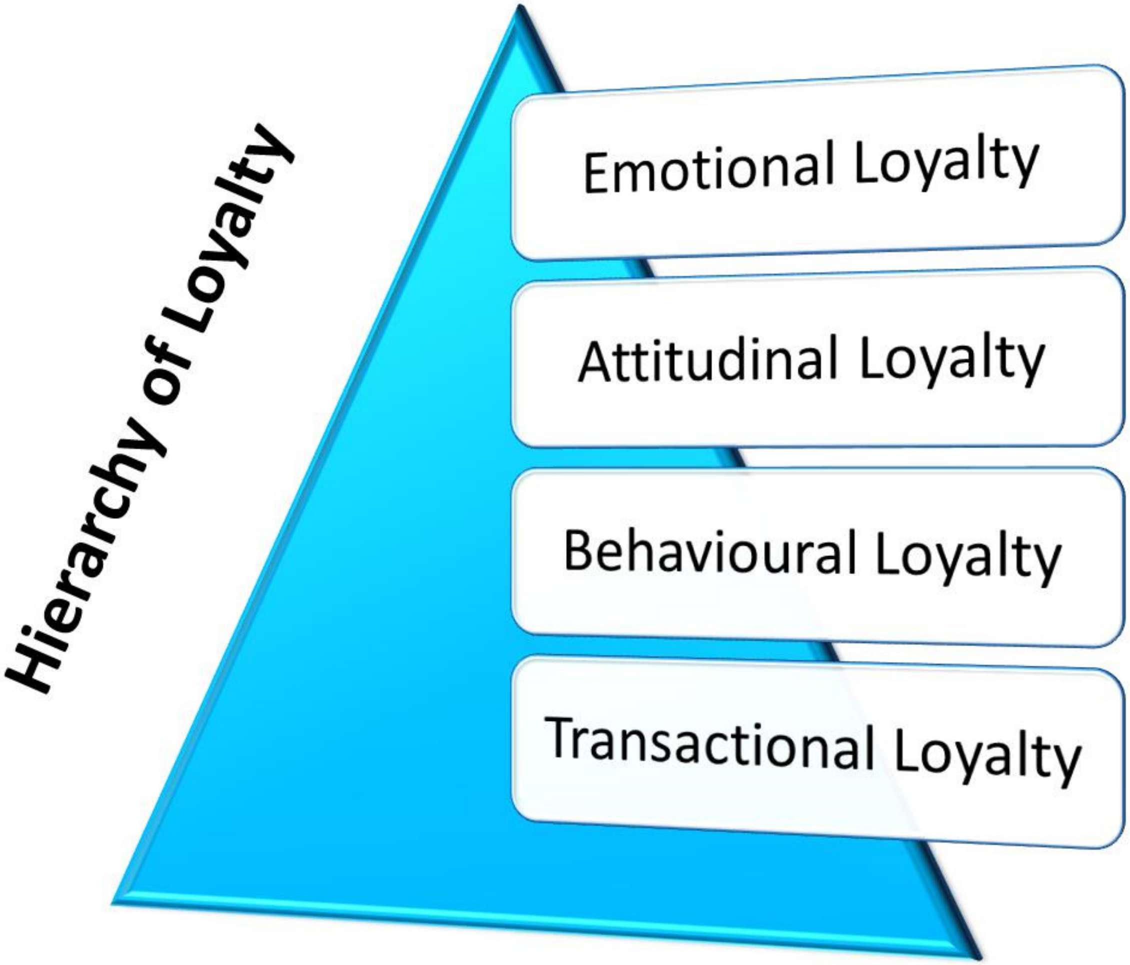
Not very knowledgeable

1%

Don't know

Base: total respondents

Customer Loyalty



Hierarchy of Loyalty

Emotional Loyalty

Attitudinal Loyalty

Behavioural Loyalty

Transactional Loyalty

Customer Loyalty

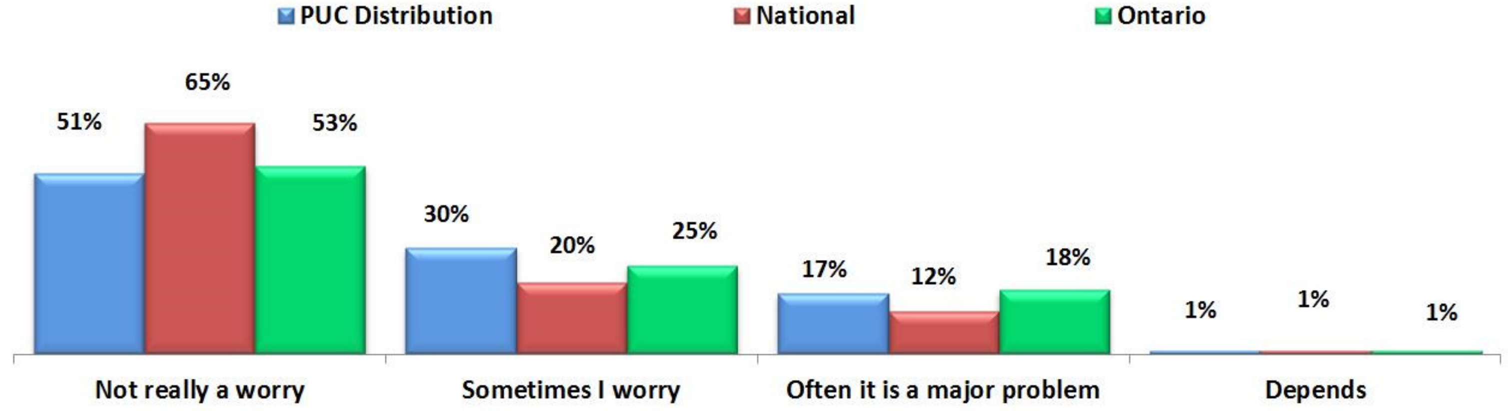
19%	18%	44%	19%
Secure	Favorable	Indifferent	At Risk

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

Is paying for electricity a worry or a major problem?



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:

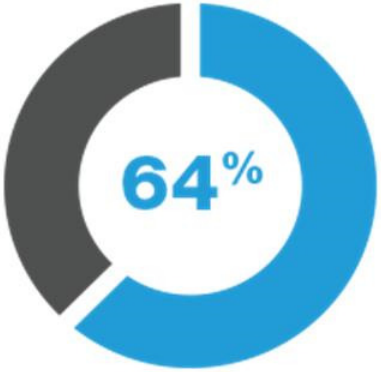
85% of Secure and Favourable respondents are confident that PUC Distribution is using good judgment to prioritize investments

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%

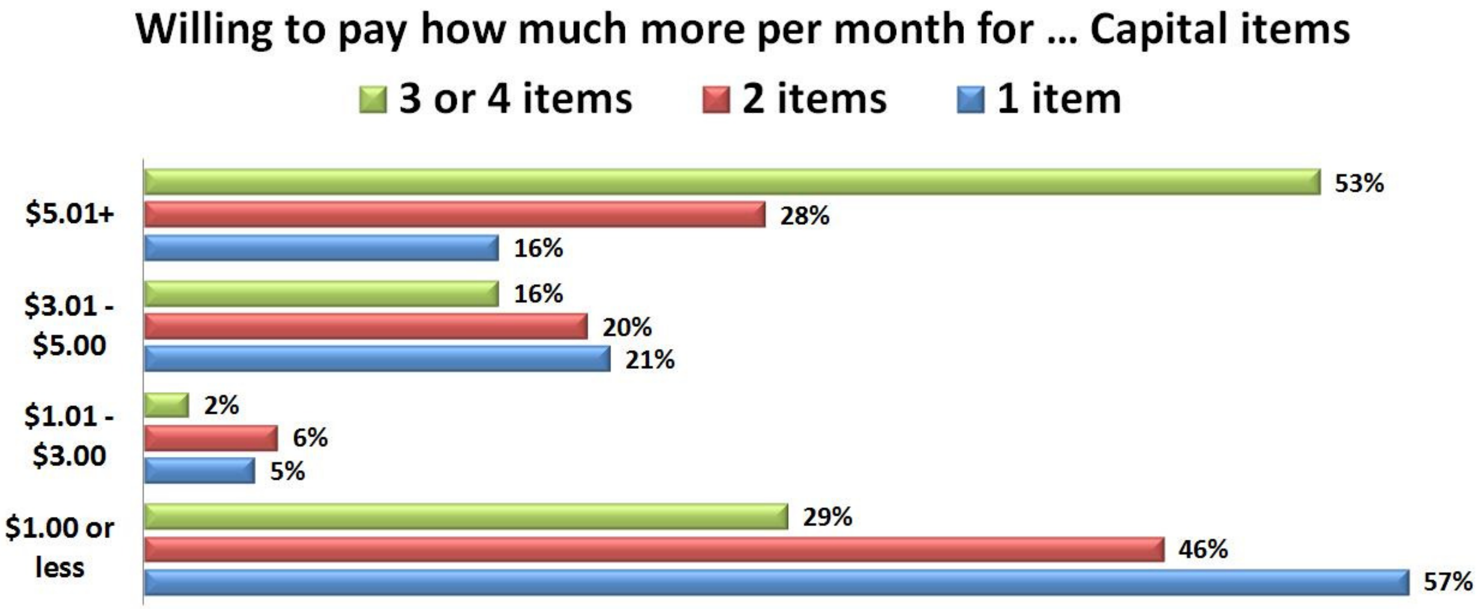
69%

"… 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?

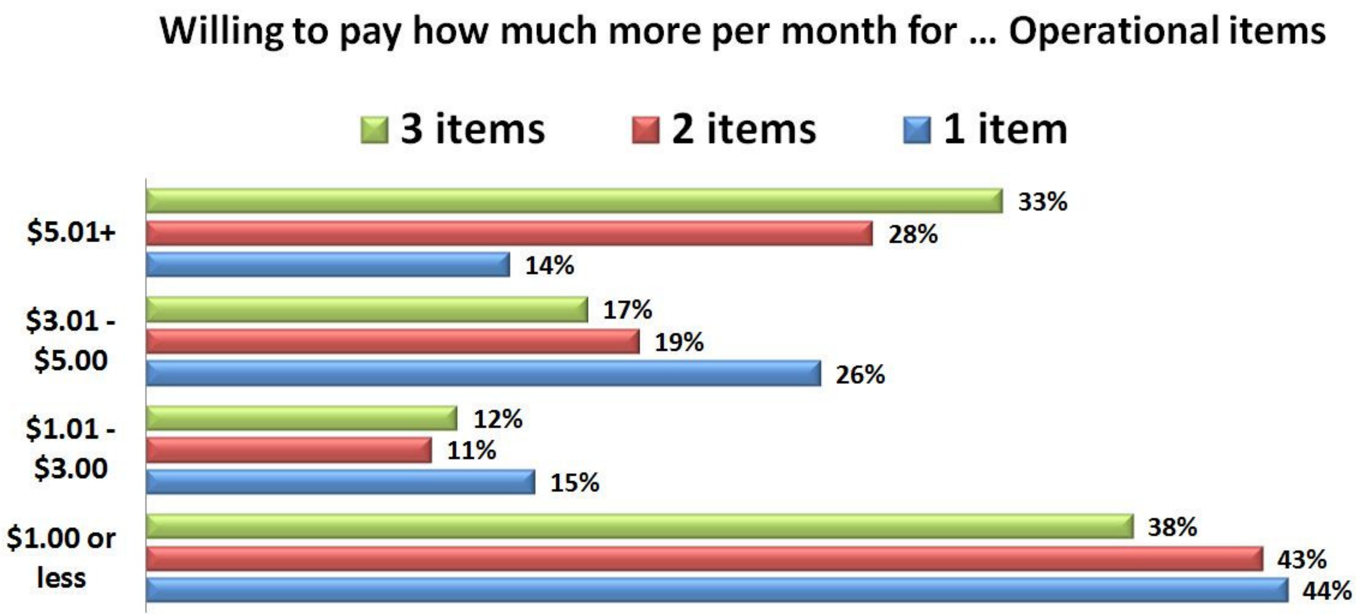
PUC Distribution	Yes	No	Not sure	Residential Yes	Small Commercial Yes
A proactive outage management system	23%	74%	3%	23%	27%
Increased self-service options on the website	13%	85%	2%	13%	12%
Educating customers about energy conservation	23%	76%	1%	23%	22%

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

Base: total respondents

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%


Willing to pay how much more per month for … Operational items

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

67%

"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

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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

UtilityPULSE

A Division of Simul Corporation

Electric Utility Customer Satisfaction Survey

This is privileged and confidential material and no part may be used outside
PUC Distribution Inc. without written permission from Simul Corporation.

All comments and questions should be addressed to:

Sid Ridgley, Simul Corporation
UtilityPULSE division
Tel: 1-905-895-7900
email: sidridgley@utilitypulse.com or sridgley@simulcorp.com

Simul

APPENDIX 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

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

	2012	2011
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:

			2012	2011
	Cost	Accumulated amortization	Net book value	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

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

	2013	2012
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

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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

PUC DISTRIBUTION INC.

Balance Sheet

December 31, 2014, with comparative information for 2013

Assets

	2014	2013
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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Sault Ste. Marie ON P6A 6L6
Canada
Telephone (705) 949-5811
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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.

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

Assets

	December 31, 2015	December 31, 2014	January 1, 2014
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
111 Elgin Street, Suite 200
Sault Ste. Marie ON P6A 6L6
Canada
Telephone (705) 949-5811
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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.

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:

Ellen Jean Richter 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

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**

2013

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	

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--Cred	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 - Inta	2120	-		-	
Accumulated Amortization of Electric Plant Acquisition	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 Payab	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 Investme	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 Generator	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**

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--Credi	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

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	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 Paya	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 Generator:	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 F	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 anc	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 - Operatior	5040	156,680.69	**27**
Underground Distribution Lines and Feeders - Operatior	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.

LA Guerriero

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.

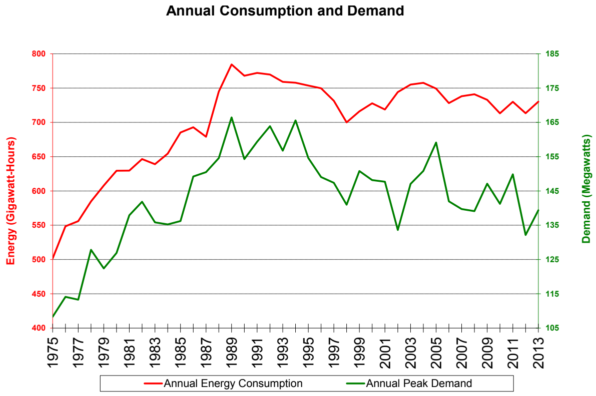
BUSINESS of PUC DISTRIBUTION INC.

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

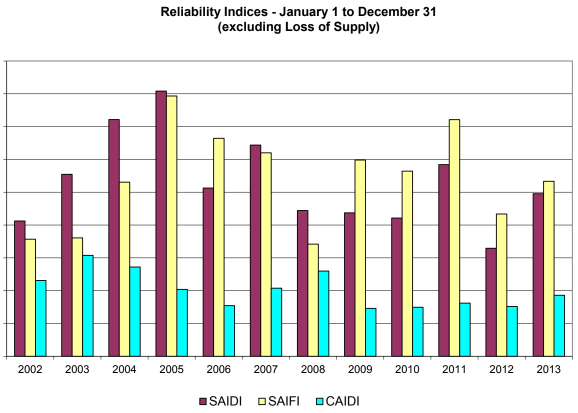


Figure 3 summarizes contributions by plant type to outage frequency and duration. There was one Loss of Supply event in 2013. Outages related to overhead plant provided the largest contribution to both outage duration and frequency, followed by transformer station equipment. Overhead plant accounted 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

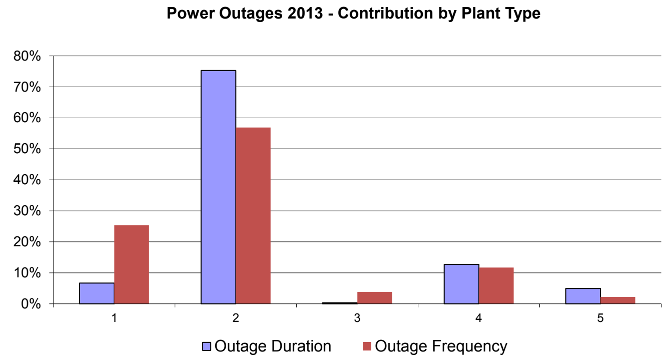


Figure 4 below summarizes the contributions by outage type for outages originating within PUC Distribution's system only (i.e. excluding the impacts of Loss of Supply). Equipment failure represented the largest impact for both duration and frequency of outages, accounting for 34% of SAIDI and 35% of SAIFI, followed closely by Trees on Lines at 32% of SAIDI and 26% of SAIFI.

Figure 4

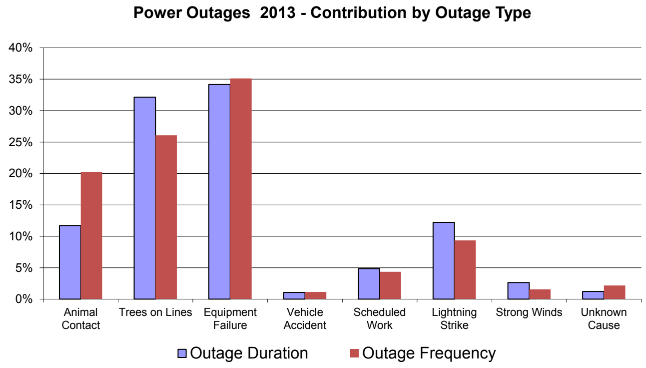


Figure 5 below summarizes the contribution of various categories of equipment failures to the annual system outage duration while Figure 6 summarizes contribution to annual outage frequency, for the period 2008 to 2013.

Figure 5

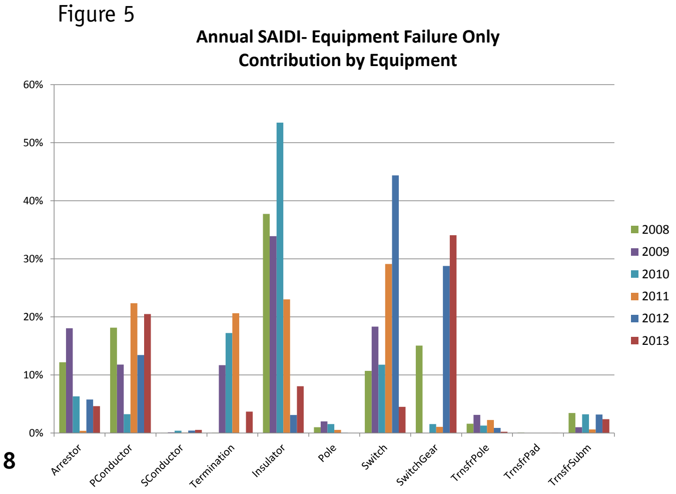
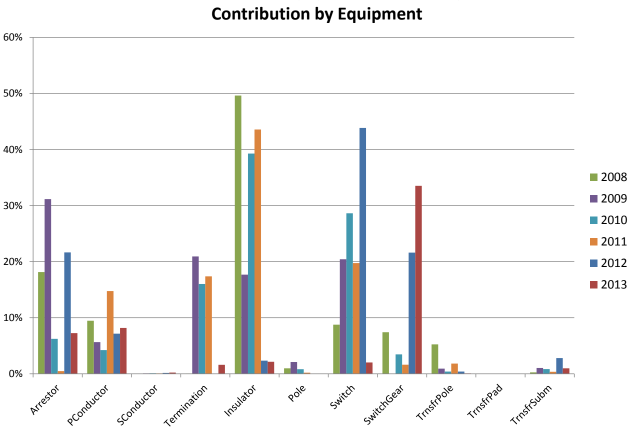


Figure 6



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.

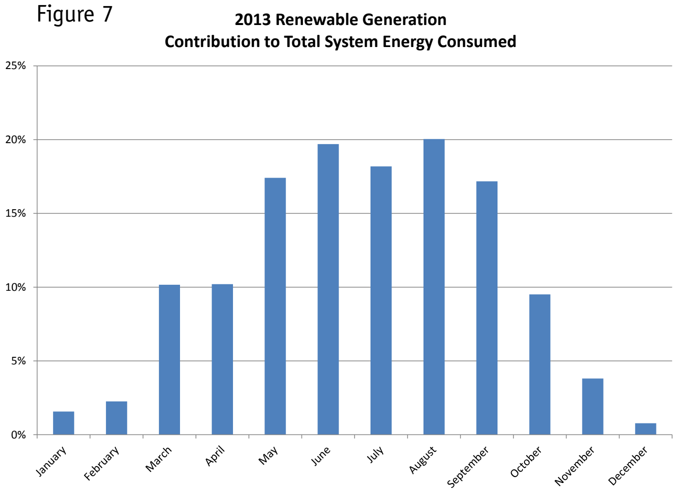
The age of the distribution system, including the distribution stations and transformer stations, makes it more vulnerable to outages. We have recognized the need to increase our level of infrastructure replacement and to improve system protection. In 2004 capital investment in renewal of the distribution 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.

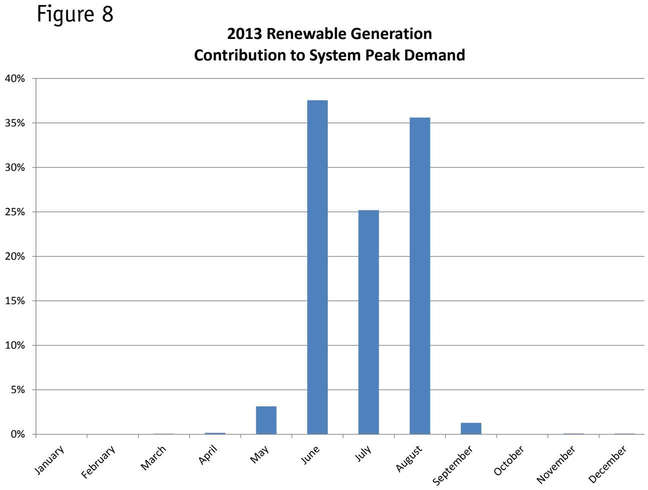
Solar generation connected to PUC Distribution's network supplied nearly 10% of the total energy consumed by PUC customers for the year 2013. Figure 7 identifies, on a monthly basis, the contribution produced by solar generation to total system energy consumed.

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.

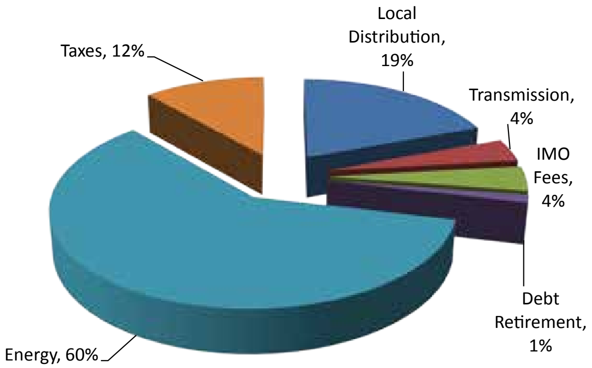
Notes Payable

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

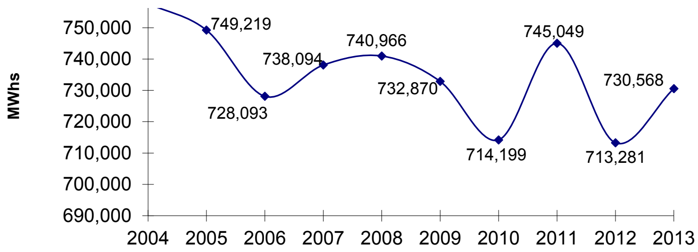
Approximately 80% of the energy revenue was collected from customers and flowed through at cost on behalf of other market participants. The remaining 20%, referred to as distribution revenue, is retained by the company to operate the local electric distribution system.

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 offset 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

PUC

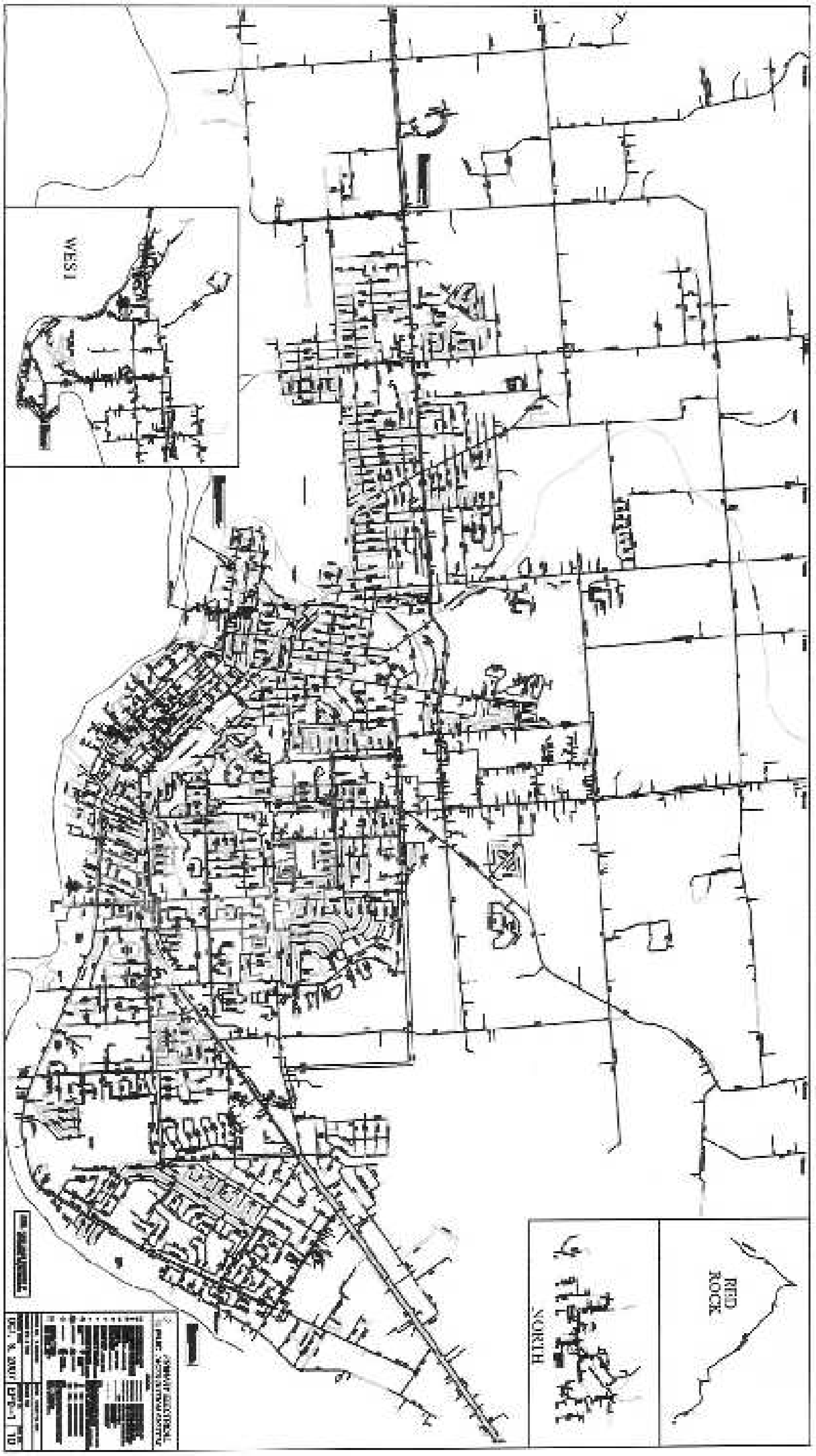
www.ssmpuc.com

500 Second Line East, PO Box 9000, Sault Ste. Marie, P6A 6P2

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	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

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.

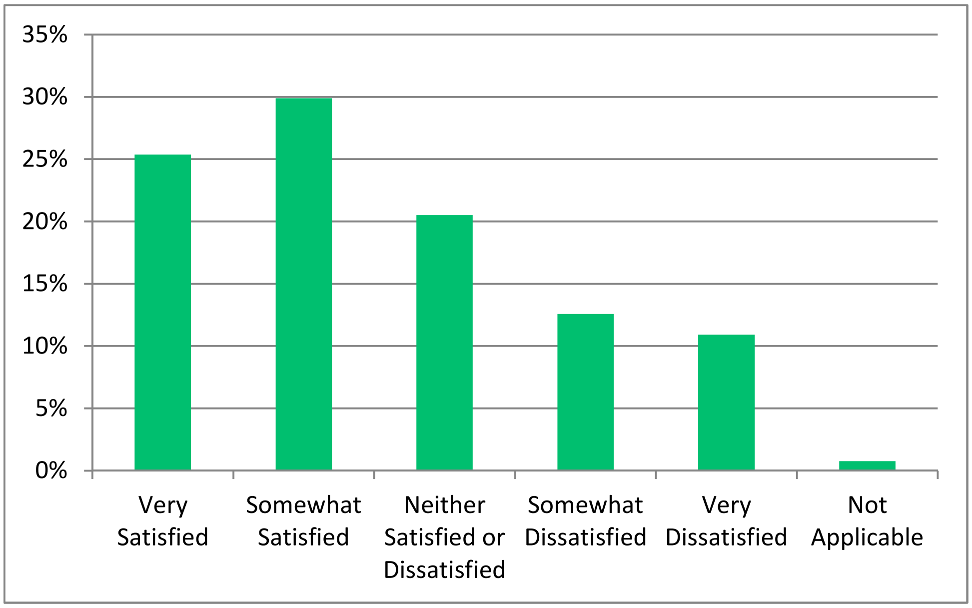
Customer Engagement Survey - DEMOGRAPHICS & SEGMENTATION

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.

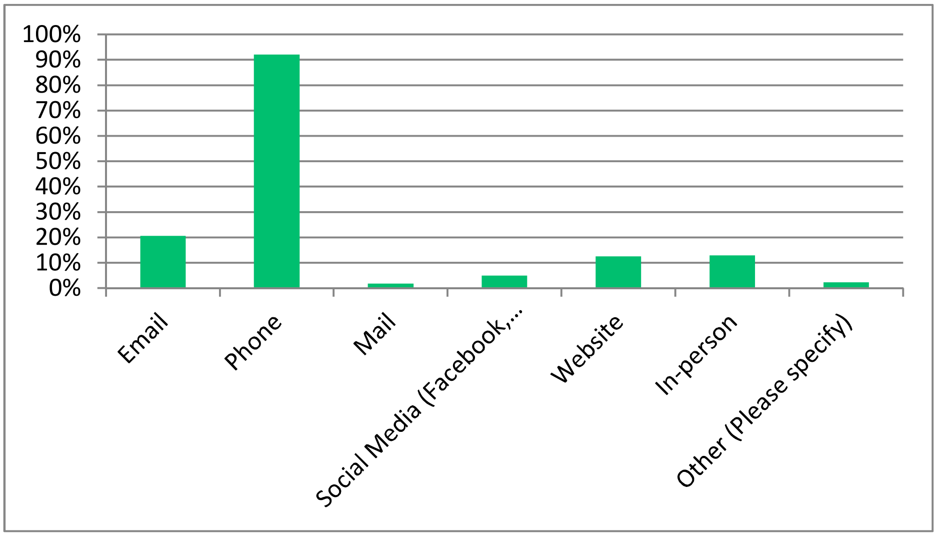
Customer Engagement Survey - PUC PRIORITIES

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

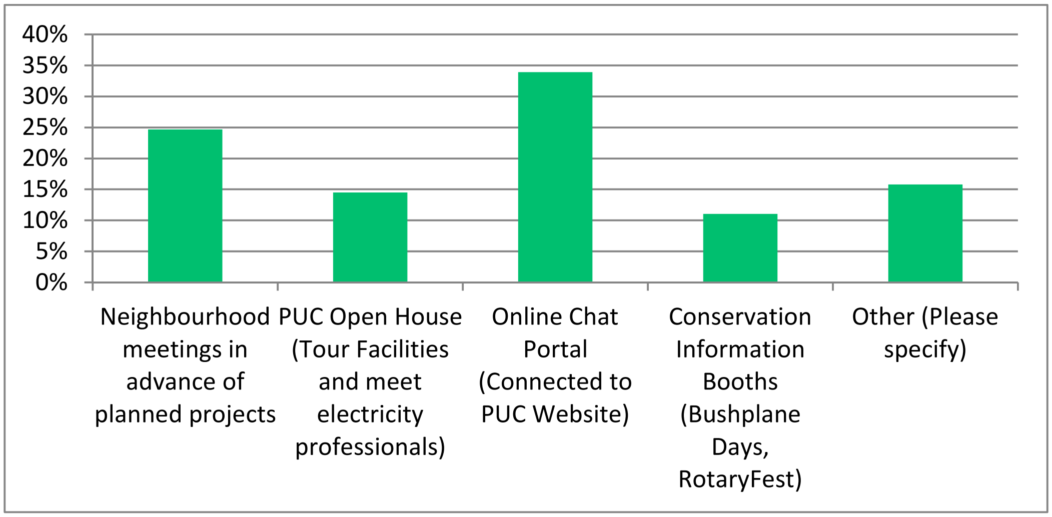


Question 14

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.

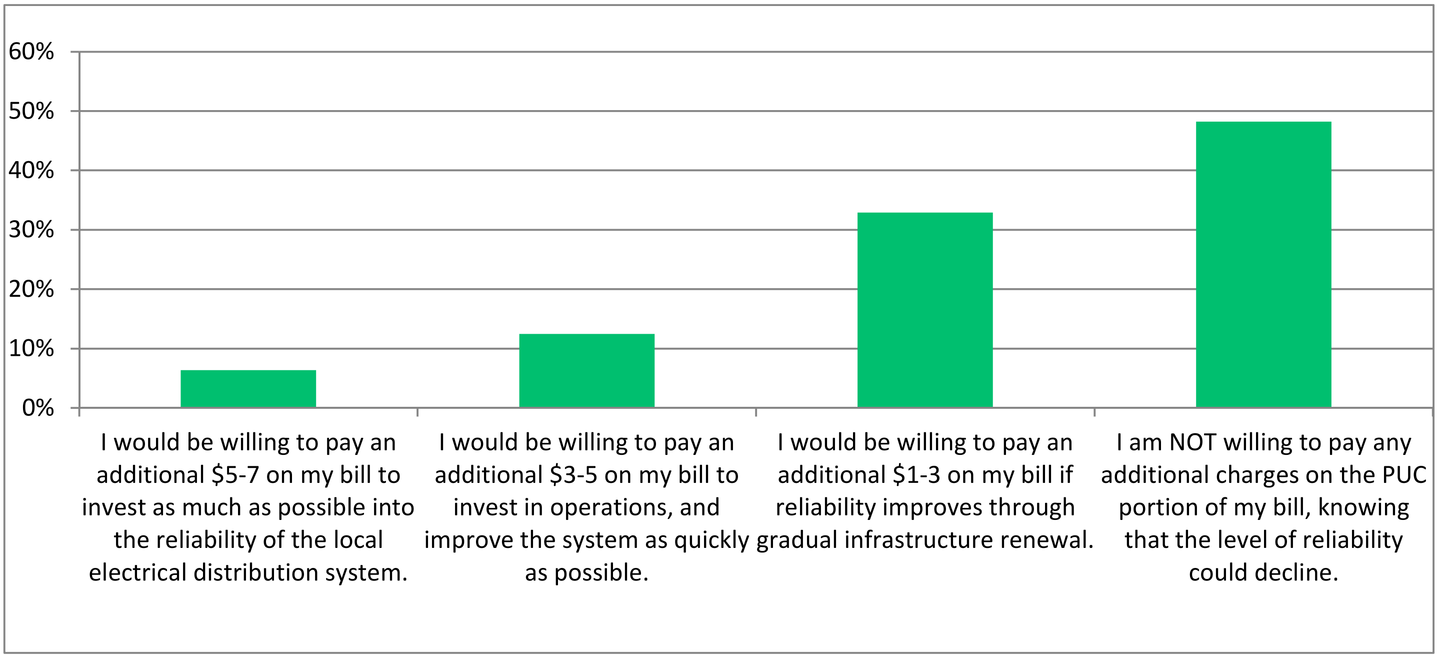
Customer Engagement Survey - OPERATIONS, MAINTENANCE & ADMINISTRATION

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.



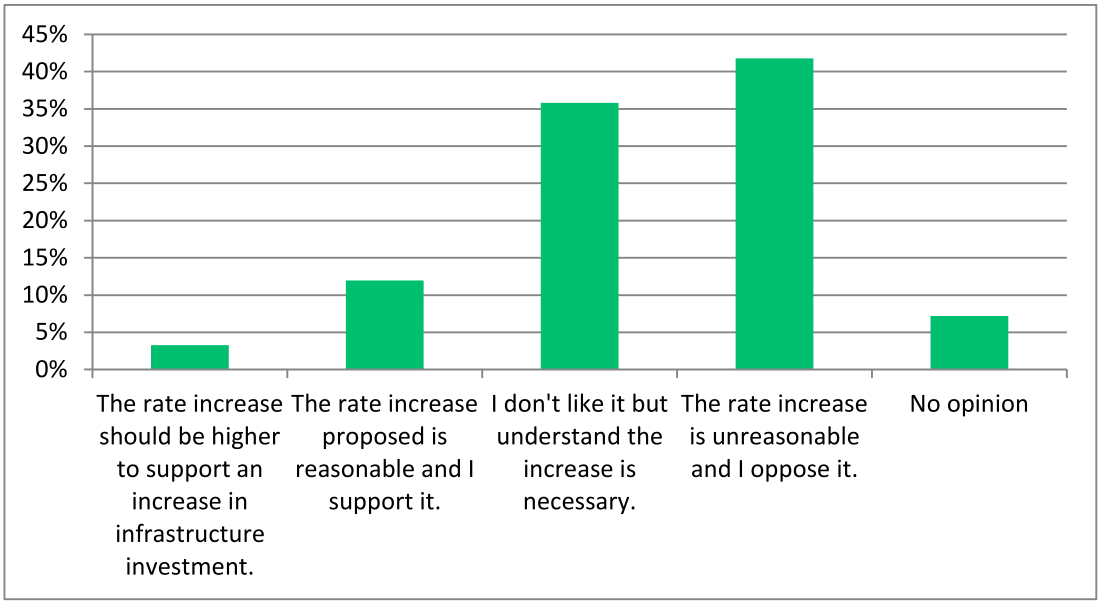
Question 22

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.

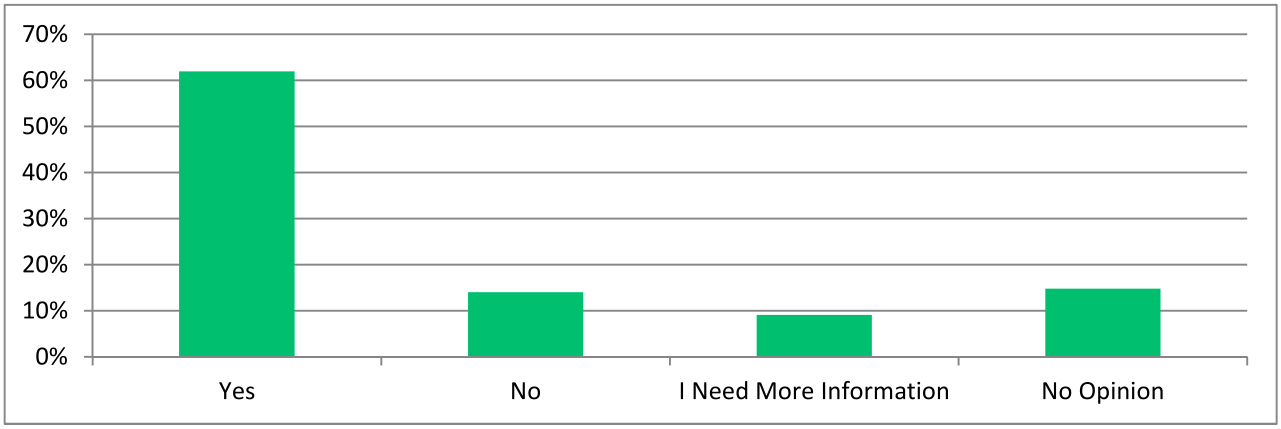
Customer Engagement Survey - PROPOSED INCREASE

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.

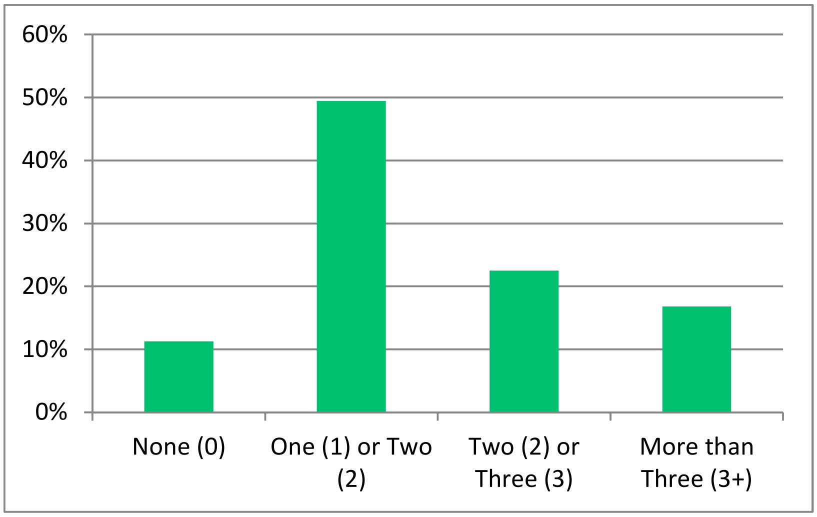
Most participants did state that they were provided with enough information in the survey to understand the reasons behind the proposed rate increase. This supports the previous question of customers understanding the rate increase is necessary, but not liking it or supporting it, based on the information 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. <u>Unless otherwise stated, the results listed below are based on the most recent (2017) Electric Utility Customer Satisfaction Survey data.</u>

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)*

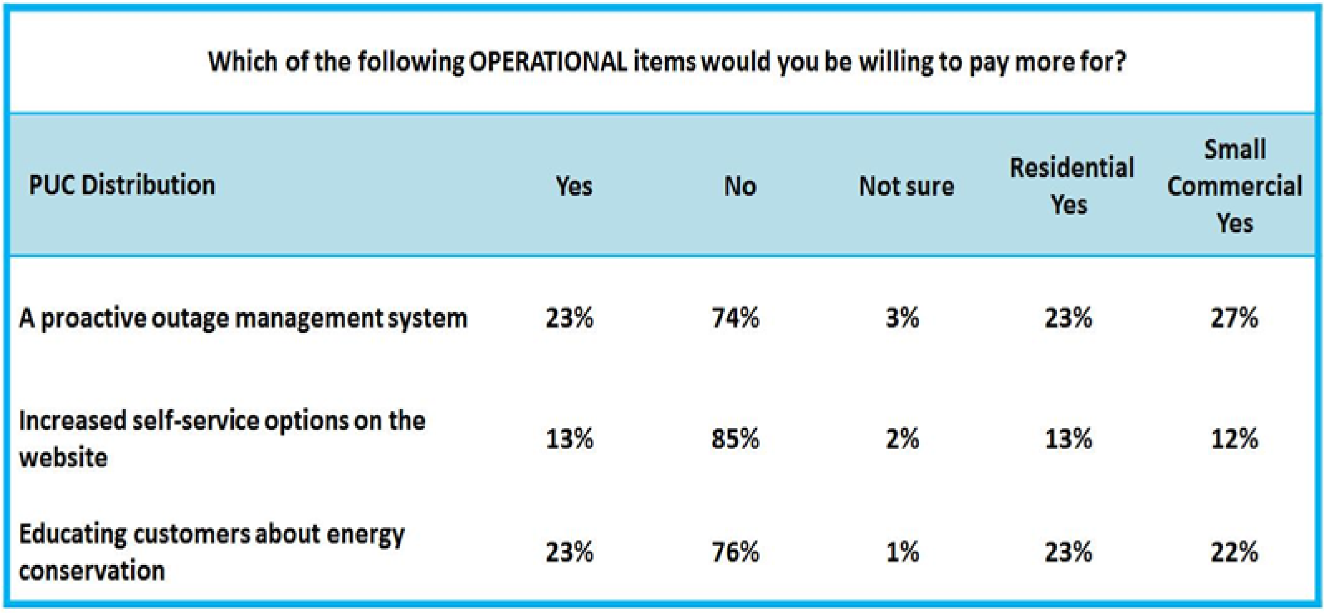
- 54% increased tree trimming
- 46% a proactive outage management system
- 46% educating customers and the public about electricity safety
- 45% educating customers about energy conservation

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)*

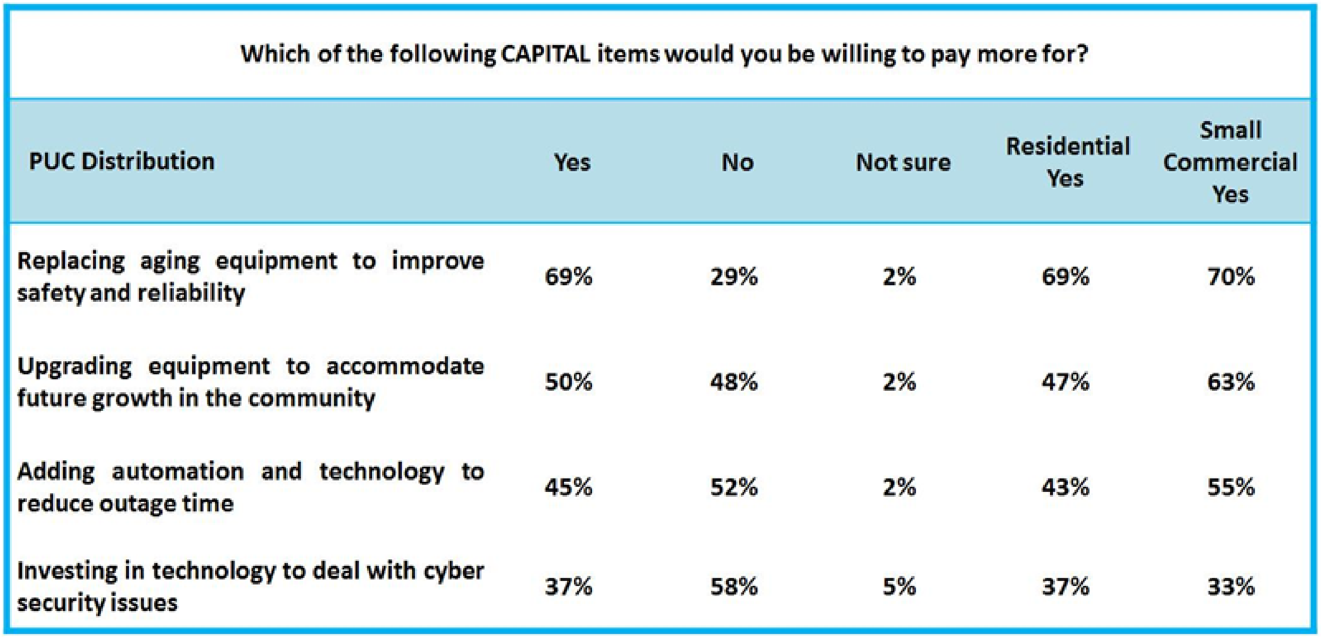
- 69% replacing aging equipment to improve safety and reliability
  - Of those who answered YES = Residential 69% / Small Commercial 70%
- 50% upgrading equipment to accommodate future growth in the community
  - Of those who answered YES = Residential 47% / Small Commercial 63%



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%

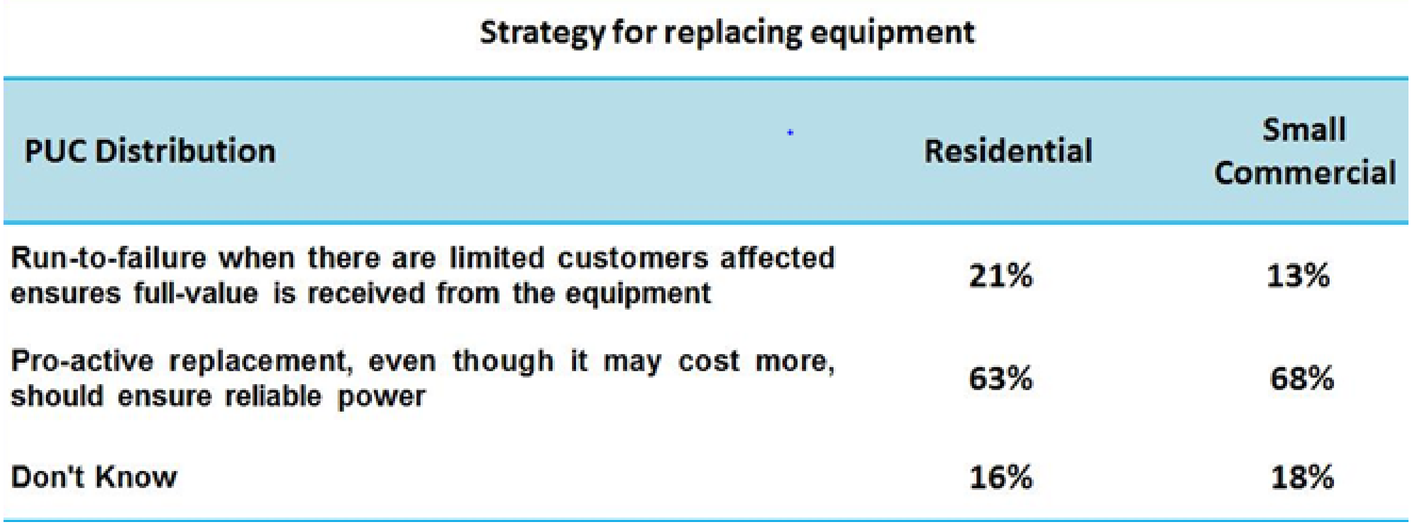
(pg. 44 – PUC Distribution Inc. 2017 UtilityPULSE Customer Satisfaction Survey)



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%

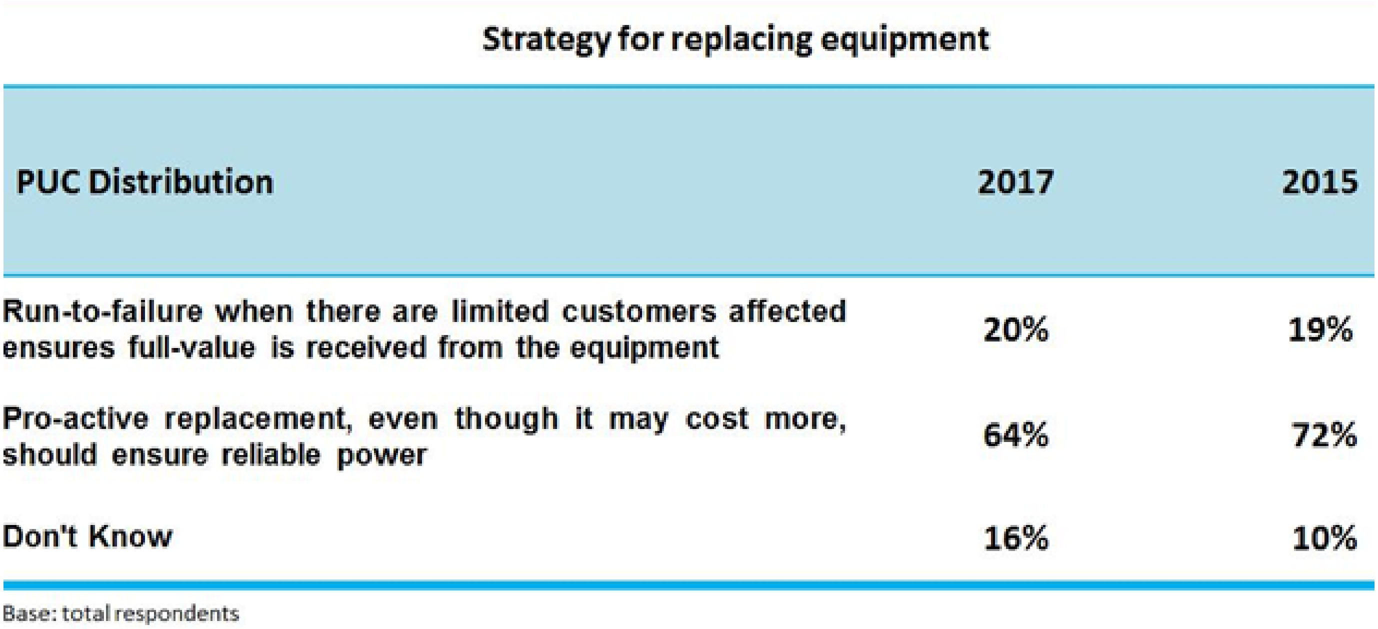
(pg. 41 – PUC Distribution Inc. 2017 UtilityPULSE Customer Satisfaction Survey)



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.”

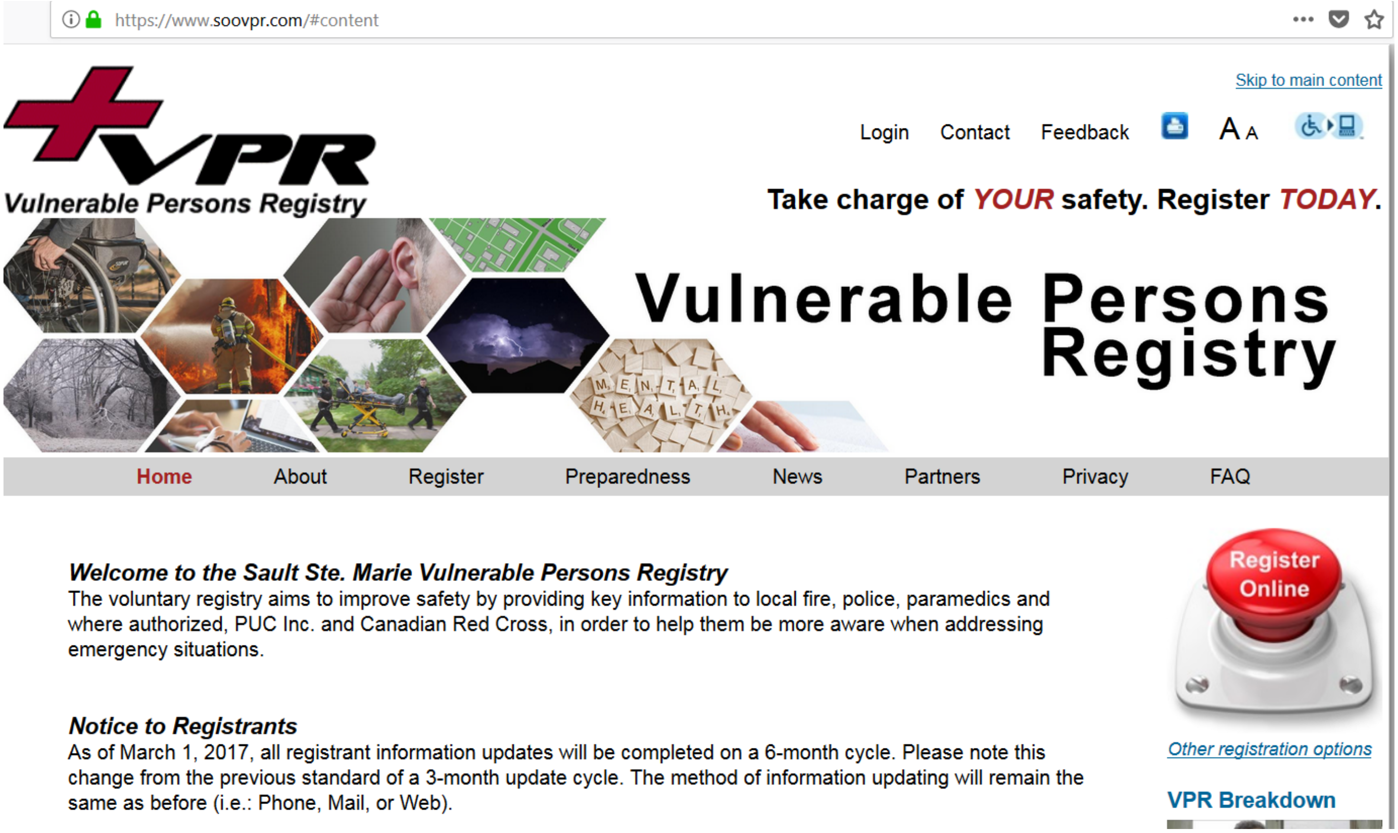
iii. While improvements were made to the emergency, unplanned outage notification system, customers expressed the desire for improvements to be made in PUC's planned outage notification process. PUC addressed these concerns by developing the Atlas Notification System. Implementing this new system required 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



Take charge of *YOUR* safety. Register *TODAY*.

Vulnerable Persons Registry

Welcome to the Sault Ste. Marie Vulnerable Persons Registry

The voluntary registry aims to improve safety by providing key information to local fire, police, paramedics and where authorized, PUC Inc. and Canadian Red Cross, in order to help them be more aware when addressing emergency situations.

Notice to Registrants

As of March 1, 2017, all registrant information updates will be completed on a 6-month cycle. Please note this change from the previous standard of a 3-month update cycle. The method of information updating will remain the same as before (i.e.: Phone, Mail, or Web).

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

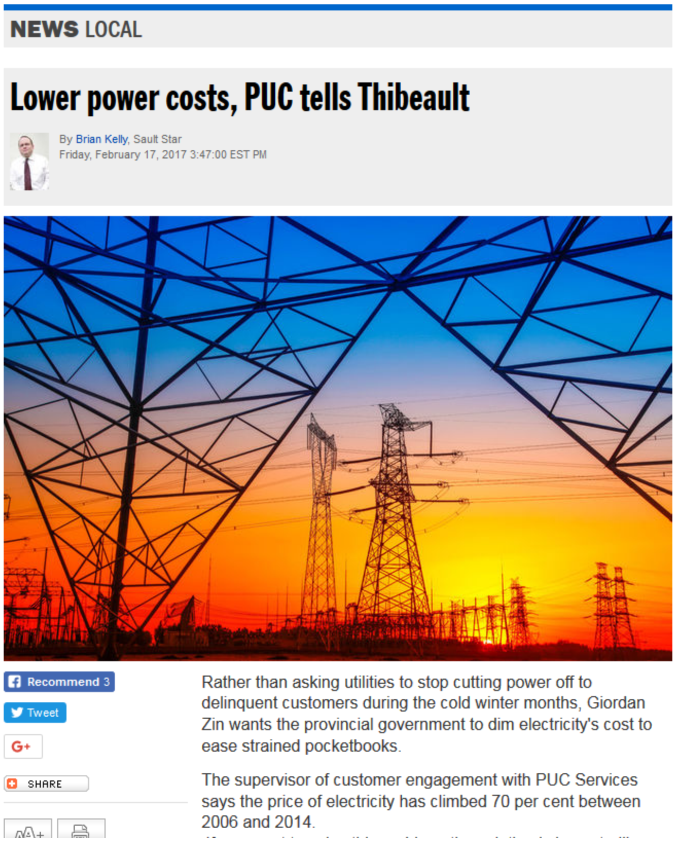
The introduction of Social Media accounts such as Facebook, in 2013 and Twitter in 2012 allowed PUC to communicate with a larger online audience and reach different target markets with messages about; worker safety, electrical shock and safety, home renovation/upgrades, energy-efficient products, electricity 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

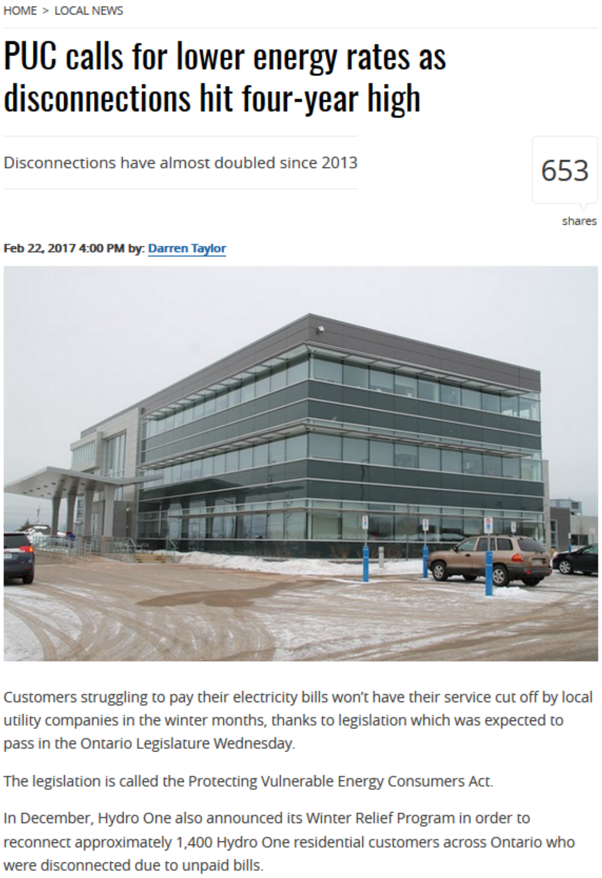
Lower power costs, PUC tells Thibeault

By Brian Kelly, Sault Star
Friday, February 17, 2017 3:47:00 EST PM

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



PUC calls for lower energy rates as disconnections hit four-year high

Disconnections have almost doubled since 2013

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.

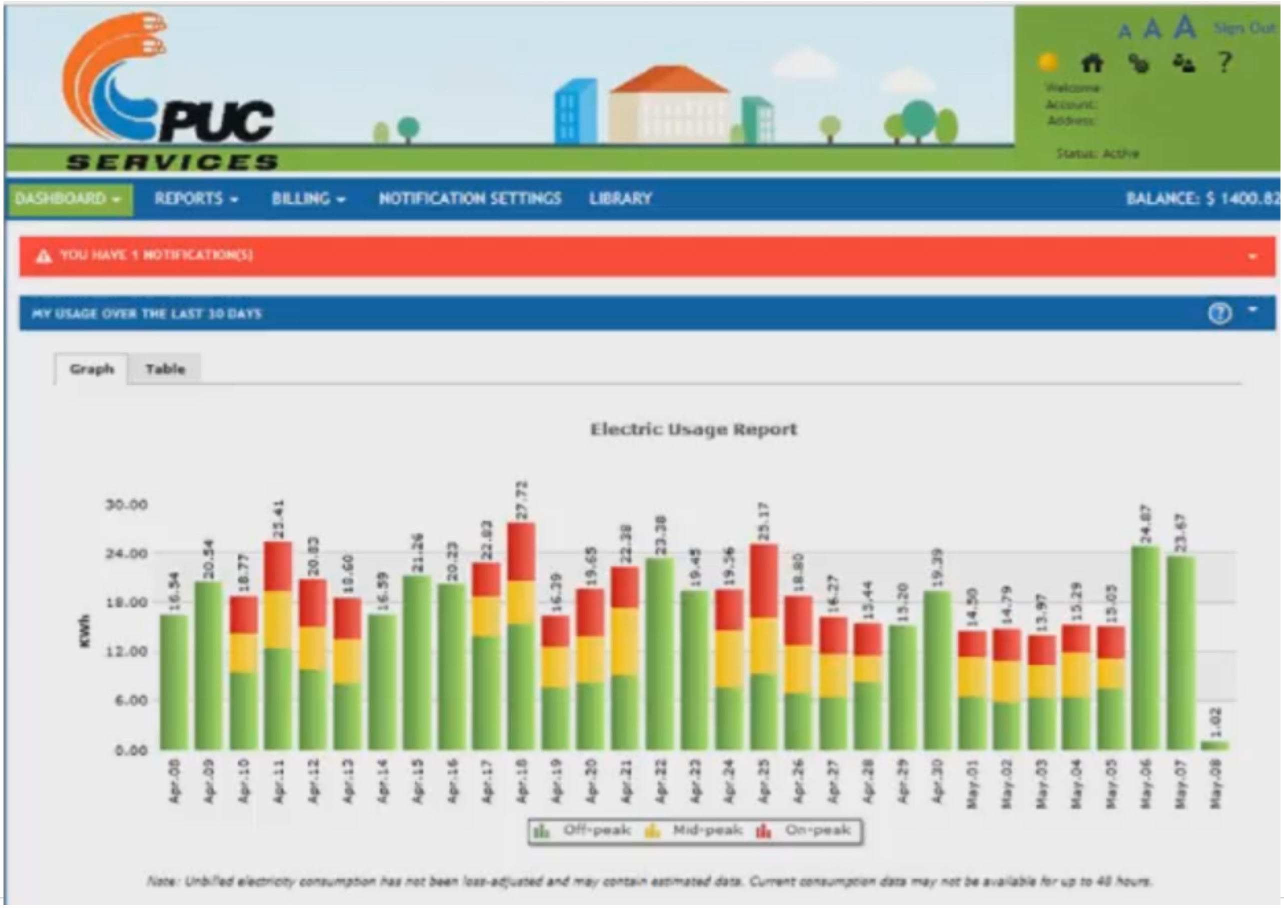
Our commitment to customer care goes beyond the Customer Care department; it involves the entire organization and includes our core value of responsiveness to our community. We are fortunate enough to have a local office where a customer can speak to an engineer about a technical question, a billing 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.



Note: Unbilled electricity consumption has not been loss-adjusted and may contain estimated data. Current consumption data may not be available for up to 48 hours.

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 <u>NOT</u> 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

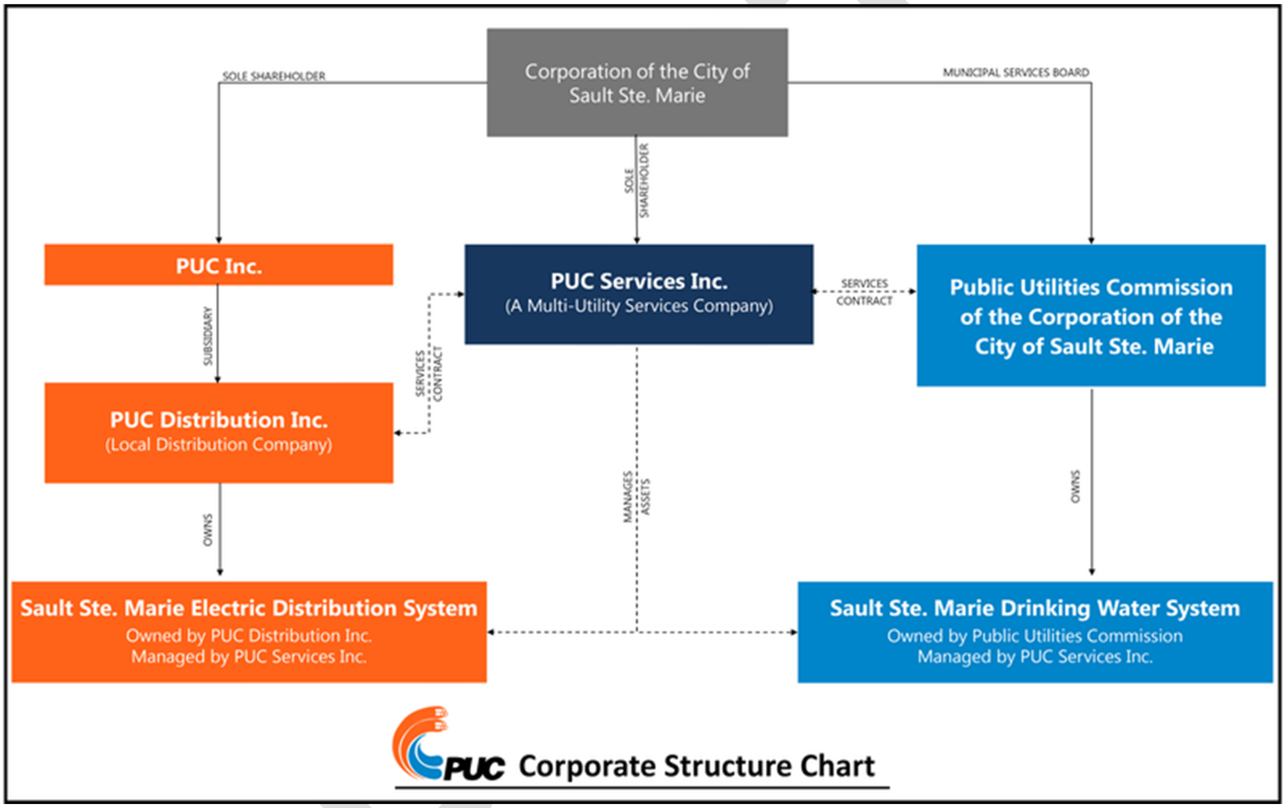
2017 to 2021

TABLE OF CONTENTS

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.

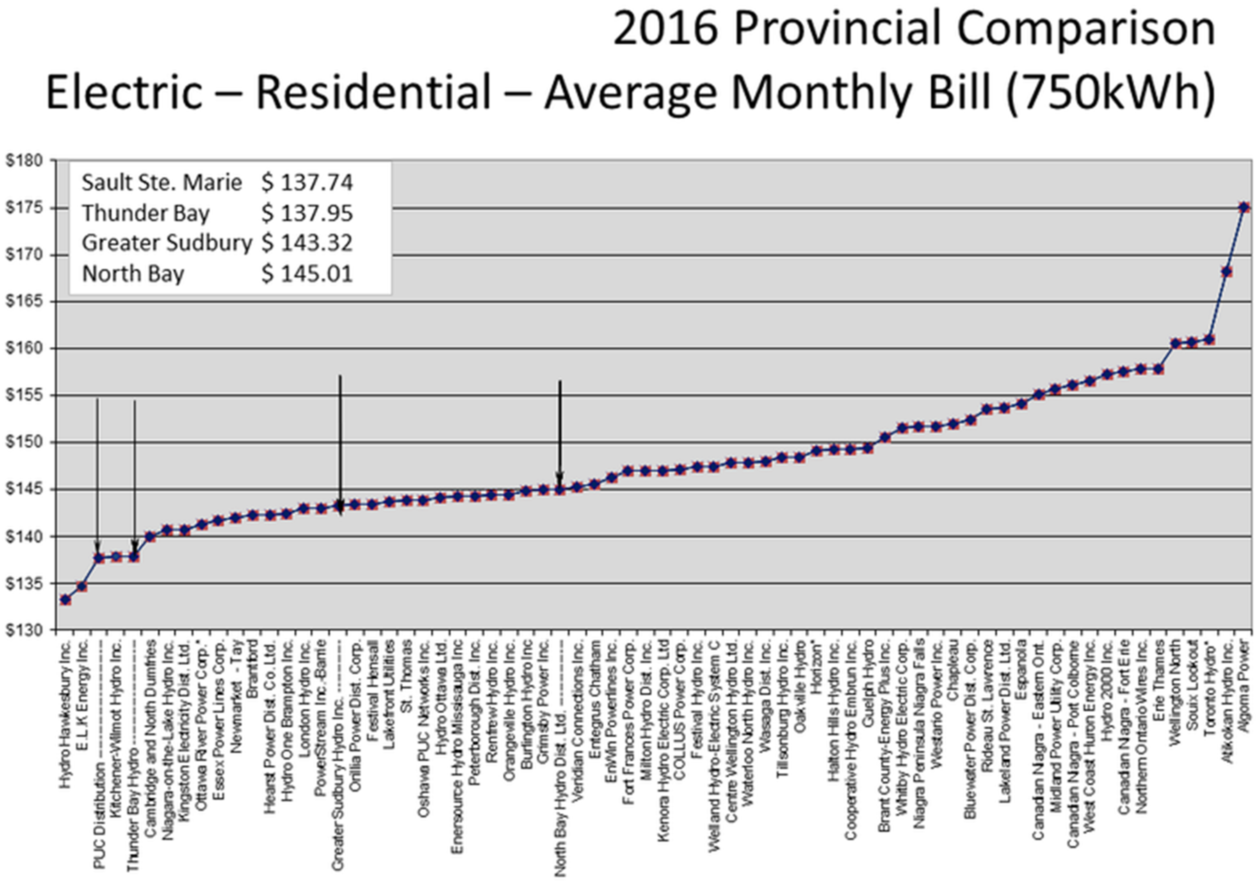
Although it does not pay corporate income taxes, as a municipally owned licenced LDC in the province of Ontario, PUC is required to pay Payments in Lieu of Taxes (PILS) to the province. The amount payable is generally speaking calculated based on Federal and Provincial tax rules for corporations.

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.

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.



2016 Provincial Comparison
Electric – Residential – Average Monthly Bill (750kWh)

(Data From OEB Website)

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

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

		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

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

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.

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:

- 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 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.

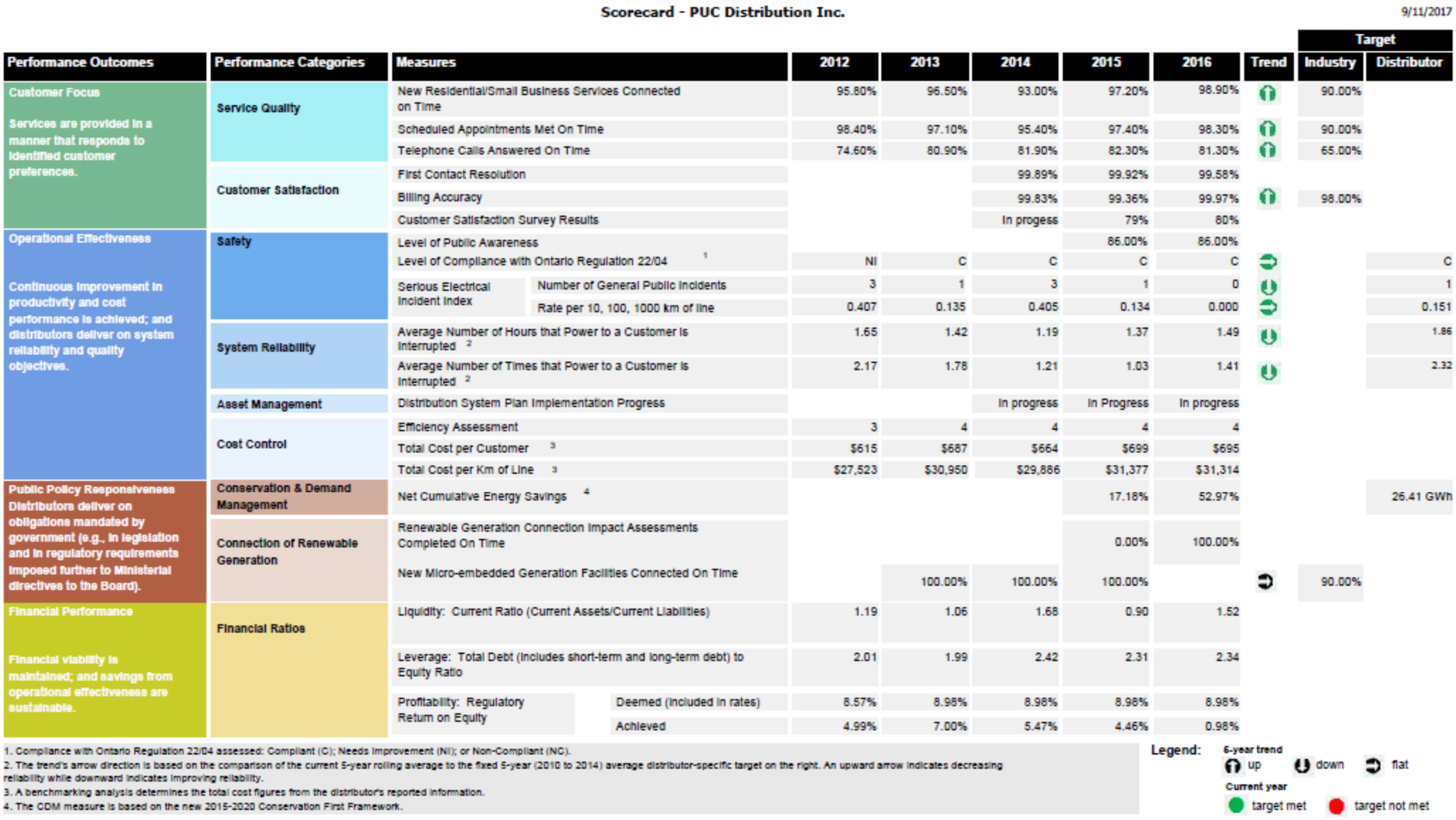
PUC Services Inc., like others in the utility services industry, faces a significant number of retirements over the next several years. The retirement of individuals in technical, trades and management positions will result in the loss of a large pool of expertise, therefore where practical replacements 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.



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%	↑	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

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%.

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, 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:

- 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.

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

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.

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

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 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 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

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

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

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

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, settlement 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%.

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.

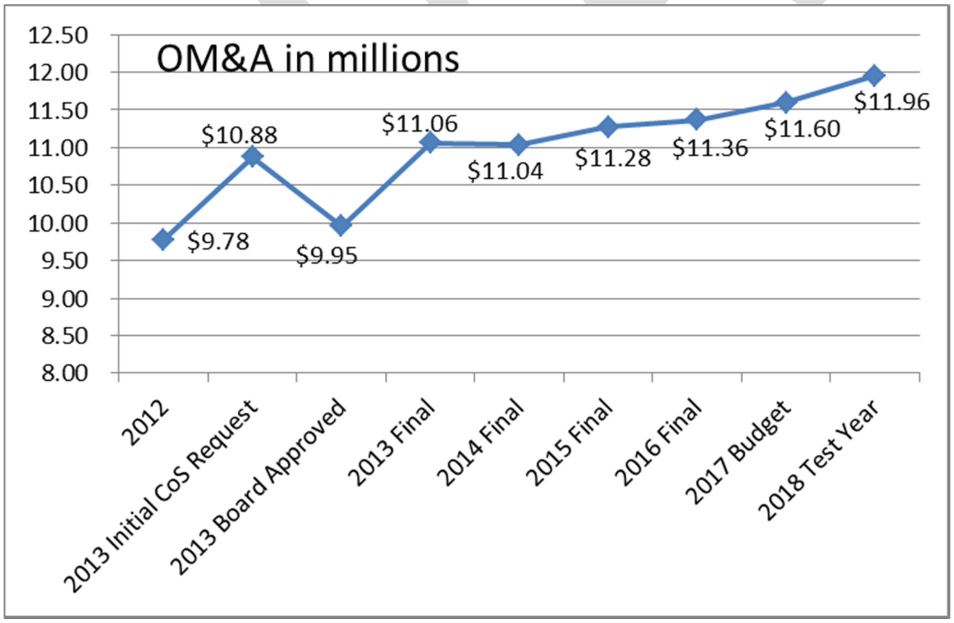
Although PUC did not receive approval for the full amount requested in rates for OM&A expenses in its last cost of service rate application in 2013, due to increased regulatory requirements and costs deemed necessary to service customers, PUC’s expenditures were $11.2 million compared to the approved 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 –

		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	

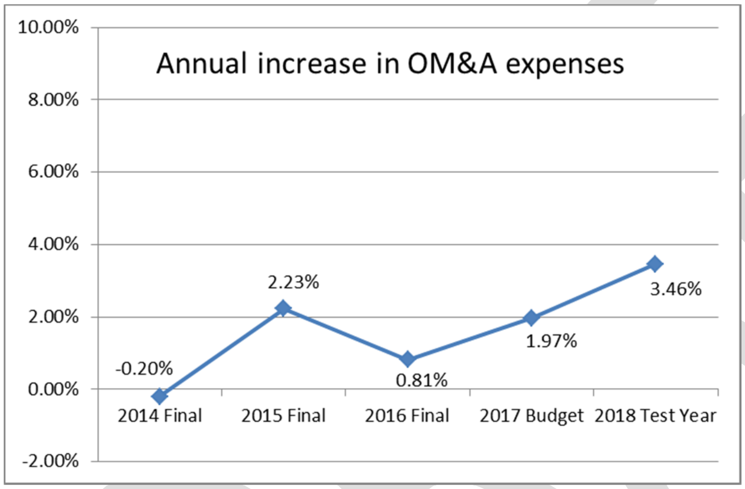
OM&A expenses have increased from $11.02 million in 2013 to $11.96 million in the 2018 test year request to be submitted to the OEB for approval. This equates to an average annual increase of 1.6%. Despite regulatory pressures, the average annual increase over the 2013 to 2018 period has been below the 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 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.

Appendix A

Pro Forma Financial Statements

PUC Distribution Inc.
Results of Operations

	For the Year Ending December 31				
	2017	2018	2019	2020	2021
	Estimated	Budget	Projected	Projected	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

EXHIBIT 2:
RATE BASE

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Exhibit 2: Rate Base

2.2.1.1 Overview

The following Exhibit provides details and analysis of the Rate Base for PUC Distribution Inc.

PUC Distribution has prepared its Rate Base for the Purpose of calculating the revenue requirement in this Application following Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications – 2017 Edition for 2018 Rate Applications issued on July 14, 2017. (“Filing Requirements”) In accordance with the Filing Requirements, PUC Distribution has calculated its Rate Base on the average of 2018 Test Year opening and 2018 Test Year closing balances of gross fixed assets and accumulated depreciation, plus a working capital allowance of 7.5%.

Net fixed assets include those distribution assets that are associated with activities that enable the conveyance of electricity for distribution purposes. The rate base calculation excludes any non-distribution assets. Controllable expenses include operations and maintenance, billing and collecting and administration expenses.

PUC Distribution has provided its rate base continuity schedule for the years 2013 Board Approved, 2013 Actual, 2014 Actual, 2015 Actual, 2016 Actual, 2017 Bridge and 2018 Test in Table 2-1 below.

Table 2-1: Rate Base Continuity Schedule

Description	2013 OEB Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**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**

PUC Distribution's assets fall into two general categories – the first is distribution plant, which includes assets such as distribution substation buildings, poles, conductor, overhead and underground electricity distribution infrastructure, transformers, meters and substation equipment. The second is general plant which includes assets such as the operations/service center building, computer equipment and software and system supervisory equipment.

In the process of transitioning to IFRS for the 2015 financial statements, PUC Distribution restated the 2014 comparators and the 2014 opening balances on the 2015 financial statements. Items of property, plant and equipment acquired prior to January 1, 2014 are measured at deemed cost established on the transition date, less accumulated depreciation.

Fixed Asset Continuity Statements

PUC Distribution has completed the Fixed Asset Continuity Schedules (Board Appendix 2-BA) for the Historical Actuals for 2012 through 2016, the 2017 Bridge Year and the 2018 Test Year.

These schedules are provided in Appendix 1 of this Exhibit and have also been filed in live excel format.

The above continuity schedules reconcile to the annual recorded depreciation expense. Table 2-2 below reconciles between annual change in accumulated depreciation and depreciation expense.

Table 2-2: Depreciation Continuity Schedule

Depreciation Expense	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test Year
Accumulated Depreciation Opening	-$ 51,244,324.00	$ -	-$ 3,366,973.00	-$ 6,669,872.00	-$ 10,213,863.00	-$13,877,445.00
Accumulated Depreciation Closing	-$ 51,278,631.00	-$ 3,366,973.00	-$ 6,669,872.00	-$ 10,213,863.00	-$ 13,877,445.00	-$17,661,400.00
Change in Accumulated Depreciation	**(34,307.00)**	**(3,366,973.00)**	**(3,302,899.00)**	**(3,543,991.00)**	**(3,663,582.00)**	**(3,783,955.00)**
Add Back Disposals	$ 2,991,134		$ 107,335			
Add Back Contributed Capital	$ 316,544	$ 341,358	$ 360,115	$ 371,428	$ 389,507	$ 407,583
Depreciation Expense	**-$ 3,341,985**	**-$ 3,708,331**	**-$ 3,770,349**	**-$ 3,915,419**	**-$ 4,053,089**	**-$ 4,191,538**

Rate Base Variance Analysis

PUC Distribution has prepared the following table to illustrate the rate base variances for each required comparator. For detailed variance explanations of these, please see section under Variance Analysis on Gross Asset Additions and section 2.2.1.3 Allowance for Working Capital respectively. The Rate Base Variance Summary is presented in Table 2-3 below.

Table 2-3: Rate Base Variance Summary

Description	2013 OEB Approved	2013 Actual	2013 Board Approved vs. 2013 Actual	2014 Actual	2013 Actual vs. 2014 Actual	2015 Actual	2014 Actual vs. 2015 Actual
Reporting Basis	**CGAAP**	**CGAAP**		**MIFRS**		**MIFRS**	
Gross Fixed Assets, Opening Balance		$ 128,112,004		$ 82,778,268	-$ 45,333,736	$ 89,439,316	$ 6,661,048
Gross Fixed Assets, Closing Balance		$ 134,056,897		$ 89,439,316	-$ 44,617,581	$ 95,587,873	$ 6,148,557
Average Gross Fixed Assets	**$ 132,327,511**	**$ 131,084,451**	**-$ 1,243,061**	**$ 86,108,792**	**-$ 44,975,659**	**$ 92,513,595**	**$ 6,404,803**
Accumulated Depreciation, Opening Balance		$ 51,244,324		$ -	-$ 51,244,324	$ 3,366,973	$ 3,366,973
Accumulated Depreciation, Closing Balance		$ 51,278,631		$ 3,366,973	-$ 47,911,658	$ 6,669,872	$ 3,302,899
Average Accumulated Depreciation	**$ 51,060,741**	**$ 51,261,478**	**$ 200,737**	**$ 1,683,487**	**-$ 49,577,991**	**$ 5,018,423**	**$ 3,334,936**
Average Net Book Value	**$ 81,266,770**	**$ 79,822,973**	**-$ 1,443,797**	**$ 84,425,306**	**$ 4,602,333**	**$ 87,495,172**	**$ 3,069,867**
Working Capital	$ 77,040,626	$ 81,010,952	$ 3,970,326	$ 81,231,909	$ 220,957	$ 89,178,814	$ 7,946,905
Working Capital Allowance (%)	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%
Working Capital Allowance	**$ 9,244,875**	**$ 9,721,314**	**$ 476,439**	**$ 9,747,829**	**$ 26,515**	**$ 10,701,458**	**$ 953,629**
Rate Base	**$ 90,511,645**	**$ 89,544,287**	**-$ 967,358**	**$ 94,173,135**	**$ 4,628,847**	**$ 98,196,630**	**$ 4,023,495**

Description	2016 Actual	2015 Actual vs. 2016 Actual	2017 Bridge	2016 Actual vs. 2017 Bridge	2018 Test Year	2017 Bridge vs. 2018 Test
Reporting Basis	**MIFRS**		**MIFRS**		**MIFRS**	
Gross Fixed Assets, Opening Balance	$ 95,587,873	$ 6,148,557	$ 101,126,227	$ 5,538,354	$ 105,808,148	$ 4,681,921
Gross Fixed Assets, Closing Balance	$ 101,126,227	$ 5,538,354	$ 105,808,148	$ 4,681,921	$ 111,166,503	$ 5,358,355
Average Gross Fixed Assets	**$ 98,357,050**	**$ 5,843,456**	**$ 103,467,188**	**$ 5,110,138**	**$ 108,487,326**	**$ 5,020,138**
Accumulated Depreciation, Opening Balance	$ 6,669,872	$ 3,302,899	$ 10,213,863	$ 3,543,991	$ 13,877,445	$ 3,663,582
Accumulated Depreciation, Closing Balance	$ 10,213,863	$ 3,543,991	$ 13,877,445	$ 3,663,582	$ 17,661,400	$ 3,783,955
Average Accumulated Depreciation	**$ 8,441,868**	**$ 3,423,445**	**$ 12,045,654**	**$ 3,603,787**	**$ 15,769,423**	**$ 3,723,769**
Average Net Book Value	**$ 89,915,183**	**$ 2,420,011**	**$ 91,421,534**	**$ 1,506,351**	**$ 92,717,903**	**$ 1,296,370**
Working Capital	$ 93,220,505	$ 4,041,691	$ 87,825,455	-$ 5,395,050	$ 91,810,701	$ 3,985,246
Working Capital Allowance (%)	12.00%	12.00%	12.00%	12.00%	7.50%	12.00%
Working Capital Allowance	**$ 11,186,461**	**$ 485,003**	**$ 10,539,055**	**-$ 647,406**	**$ 6,885,803**	**-$ 3,653,252**
Rate Base	**$ 101,101,643**	**$ 2,905,013**	**$ 101,960,588**	**$ 858,945**	**$ 99,603,706**	**-$ 2,356,883**

2.2.1.2 Gross Assets – Property, Plant & Equipment and Depreciation

Breakdown by Function

The tables below categorizes PUC Distribution's assets into four categories; transmission plant, distribution plant, general plant, and contributions and grants. In accordance with the Uniform System of Accounts ("USoA"), PUC Distribution has included gross assets as follows:

- Transmission Plant Assets – includes USoA accounts 1706-1740, these accounts capture assets such as transmission poles, wires, and transformers.
- Distribution Plant Assets – includes USoA accounts 1805-1860, these accounts capture assets such as substation equipment, poles, wires, transformers and meters.
- General Plant Assets – includes USoA account 1905 to 1990, these accounts capture assets such as operation service center buildings, computer hardware and software and system supervisory equipment.
- Contributions and Grants – includes USoA account 1995, this account captures all contributions in aid of capital that PUC Distribution has received or forecasted to be received as per the Distribution System Code. PUC Distribution has presented USoA account 1995 on a net basis from 2012 to 2016. Going forward, PUC Distribution has separated the gross contributions from the depreciation portion, which will be reported in USoA account 2105. Details of 1995 Capital Contributions has been presented in Table 2-4 below.

Table 2-4: Contributions

Description	OEB Account	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge Year	2018 Test Year
Contributions	1995	(785,722)	(1,376,260)	(1,045,731)	(454,801)	(450,272)	(996,060)	(450,000)

	OEB Account	Opening Net Balance	IFRS Adjustment	Contributions	Amortization of Contributions	Contribution Closing Balance Net Balance
2012	1995	(9,598,438)		(785,722)	282,137	(10,102,023)
2013	1995	(10,102,023)		(1,376,260)	316,544	(11,161,739)
2014	1995	(11,161,739)		(1,045,731)	341,358	(11,866,112)
2015	1995	(11,866,112)		(454,801)	360,115	(11,960,798)
2016	1995	(11,960,798)		(450,272)	371,428	(12,039,642)
2017	1995	(12,039,642)		(996,060)	389,507	(12,646,195)
2018	1995	(12,646,195)		(450,000)	407,583	(12,688,612)

Variance Analysis on Gross Asset Additions

The following variance analysis has been prepared based on PUC Distribution's materiality threshold; per the materiality calculation being noted in Exhibit 1, Section 1.7 of this Application. PUC Distribution has chosen to use $110,400 as its basis for the variance analysis of Gross Asset Additions.

2013 Board Approved vs. 2013 Actual

PUC Distribution is showing an overall decrease in gross assets between 2013 Board Approved and 2013 Actual of ($2,257,916), as can be seen in the following Table 2-5.

Table 2-5: 2013 Board Approved vs. 2013 Actual

Description	2013 Board Approved	2013 Actuals	Variance from 2013 Board Approved
Reporting Basis	CGAAP	CGAAP	
Transmission Plant			
1706 - Land Rights	-	602,307	602,307
1725 - Poles and Fixtures	-	1,753,487	1,753,487
1730 - Overhead Conductors and Devices	-	90,074	90,074
1735 - Underground Conduit	-	985,867	985,867
1740 - Underground Conductors and Devices	-	244,819	244,819
Sub-Total Intanglible Plant	**-**	**3,676,554**	**3,676,554**
Distribution Assets			
1805 - Land	97,592	89,160	(8,432)
1806 - Land Rights	836,582	154,128	(682,454)
1808 - Buildings and Fixtures	24,158,823	25,999,886	1,841,063
1815 - Transformer Station Equipment - Normally Primary above 50 kV	8,801,127	9,056,274	255,147
1820 - Distribution Station Equipment - Normally Primary below 50 kV	12,120,659	14,481,291	2,360,632
1825 - Storage Battery Equipment	19,241	19,241	-
1830 - Poles, Towers and Fixtures	16,106,994	15,168,788	(938,206)
1835 - Overhead Conductors and Devices	15,153,616	13,952,281	(1,201,335)
1840 - Underground Conduit	11,695,443	10,853,111	(842,332)
1845 - Underground Conductors and Devices	21,365,809	20,163,321	(1,202,488)
1850 - Line Transformers	16,944,406	17,435,094	490,688
1855 - Services	6,122,449	4,905,828	(1,216,621)
1860 - Smart Meters	6,490,409	6,340,345	(150,064)
Sub-Total Distribution Assets	**139,913,150**	**138,618,748**	**(1,294,402)**
General Plant			
1920 - Computer Equipment - Hardware	25,338	20,338	(5,000)
1925 - Computer Software	554,880	535,508	(19,372)
1980 - System Supervisory Equipment	4,459,426	4,354,818	(104,608)
Sub-Total General Plant	**5,039,644**	**4,910,664**	**(128,980)**
Capital Contributions			
1995 - Contributions and Grants	(8,637,981)	(13,149,069)	(4,511,088)
Sub-Total Capital Contributions	**(8,637,981)**	**(13,149,069)**	**(4,511,088)**
GROSS ASSET TOTAL	**136,314,813**	**134,056,897**	**(2,257,916)**

The following table summarizes the major components of the ($2,257,916) variance between the 2013 Board Approved and 2013 Actual Gross Assets.

Variance 2012 Bridge Estimate to 2012 Actual	($426,422)
Work in Progress Presentation in 2013 Board Approved	($4,099,831)
Disposals not included in 2013 Board Approved	($178,323)
Variance in actual additions 2013 Board Approved to 2013 Actual (see below)	$2,446,660
	($2,257,916)

Aggregated variances from all fixed asset accounts totalled $426,422 as a result of variances from the estimates included in the 2012 Bridge Year filed with the 2013 Cost of Service application as compared to the 2012 Actuals. In addition, the presentation of contributed capital was shown net of amounts recorded in work in progress in the 2013 Board Approved column. In the years thereafter, the fixed assets do not include work in progress.

There were no disposals included for 2013 in the Board Approved amounts, however, there were disposals of $178,323 included in the 2013 Actual.

For the 2013 Cost of Service rate application PUC Distribution's transmission assets were included with distribution assets as the OEB spreadsheet models did not allow for inclusion of accounts 1706 to 1740. As a result, a variance between the 2013 Board Approved and 2013 Actual is showing in these accounts from this change in presentation of the transmission accounts.

Excluding the presentation reclass between transmission and distribution accounts and presentation of work in progress, PUC Distribution's capital expenditures in 2013 were $10,421,265 compared to the Board Approved of $7,974,605. The following summarizes this variance of $2,446,660 between 2013 Board Approved and 2013 actual gross asset additions.

ACCOUNT 1808 Building & Fixtures $1,861,467

- Completion of Integrated Administrative and Operations building including landscaping, parking lot paving, etc.

ACCOUNT 1815 Transformer Station Equipment $401,596

- Transmission Station fencing and grounding replacement

ACCOUNT 1820 Distribution Station Equipment $2,360,632

- Rebuild of Distribution Station - Sub 10
- Distribution Station upgrades – Under Frequency Load Shedding relay installation, switch replacements

ACCOUNT 1830 Poles, Towers and Fixtures $1,080,200

- Joint use work – Work completed for the Bell Alliant Fiber to Home Project
- Overhead renewal program – Replace deteriorated poles at various locations as required
- Forced overhead renewal – due to storm damage, traffic accidents, equipment failure, etc.
- Restricted wire replacement – Morrison/Anita Boulevard, Third Line East
- Insulator replacement program - Porcelain Insulator Replacement Program
- Sub 10 – 35kV Blake Ave. feeder

ACCOUNT 1835 Overhead Conductors and Devices ($1,103,729)

- Reduced Voltage Conversion work from estimated level in 2013 Board Approved as a result of increased expenditures Joint use work completed for the Bell Alliant Fiber to Home Project
- Overhead renewal program – Replace deteriorated poles at various locations as required
- Forced overhead renewal (renewal due to storm damage, traffic accidents, equipment failure, etc.)
- Restricted wire replacement – Morrison/Anita Boulevard, Third Line East
- Switch Replacements – defective switch replacement program
- Sub 10 – 35kV Blake Ave. feeder

ACCOUNT 1845 Underground Conductors and Devices ($957,584)

- Reduced Underground Cable Injection and Renewal work from the estimated level in 2013 Board Approved as a result of increased expenditures for Customer Demand and Joint use work completed for the Bell Alliant Fiber to Home Project
- City Projects – Fort Creek Aqueduct, Queen St. road reconstruction

- New services and subdivisions – Denwood Subdivision (Phase VI), Heritage Discovery Center, Windsor Farms Subdivision (Phase III)

ACCOUNT 1850 Line Transformers $515,738

- New services and subdivisions – Fox Run Subdivision, Heritage Discovery Center, Windsor Farms Subdivision (Phase III)

ACCOUNT 1855 Services ($1,216,621)

- Reduced demand for New Services from the estimated level in 2013 Board Approved
- New services and subdivisions – Fox Run Subdivision, Denwood Subdivision (Phase VI), Windsor Farms Subdivision (Phase III),

2013 Actual vs. 2014 Actual

PUC Distribution experienced an overall decrease in gross assets between 2013 Actual and 2014 Actual of $44,617,581, as can be seen in the following Table 2-6. The primary driver for the decrease is the conversion to International Financial Reporting Standards (IFRS) whereby the December 31, 2013 closing accumulated depreciation was netted against gross assets at January 1, 2014. The reduction to gross assets as a result of this restatement is offset by actual gross asset additions in 2014.

Table 2-6: 2013 Actual vs. 2014 Actual

Description	2013 Actuals	2014 Actuals	Variance between 2014 Actuals and 2013 Actuals
Reporting Basis	CGAAP	MIFRS	
Transmission Plant			
1706 - Land Rights	602,307	602,307	-
1725 - Poles and Fixtures	1,753,487	1,604,340	(149,147)
1730 - Overhead Conductors and Devices	90,074	63,894	(26,180)
1735 - Underground Conduit	985,867	870,021	(115,846)
1740 - Underground Conductors and Devices	244,819	215,252	(29,567)
Sub-Total Intanglible Plant	**3,676,554**	**3,355,814**	(320,740)
Distribution Assets			
1805 - Land	89,160	89,160	-
1806 - Land Rights	154,128	160,926	6,798
1808 - Buildings and Fixtures	25,999,886	24,869,821	(1,130,065)
1815 - Transformer Station Equipment - Normally Primary above 50 kV	9,056,274	6,109,645	(2,946,629)
1820 - Distribution Station Equipment - Normally Primary below 50 kV	14,481,291	9,057,776	(5,423,515)
1825 - Storage Battery Equipment	19,241	13,722	(5,519)
1830 - Poles, Towers and Fixtures	15,168,788	12,728,383	(2,440,405)
1835 - Overhead Conductors and Devices	13,952,281	9,305,779	(4,646,502)
1840 - Underground Conduit	10,853,111	2,828,168	(8,024,943)
1845 - Underground Conductors and Devices	20,163,321	12,019,819	(8,143,502)
1850 - Line Transformers	17,435,094	9,850,027	(7,585,067)
1855 - Services	4,905,828	5,002,146	96,318
1860 - Smart Meters	6,340,345	4,610,062	(1,730,283)
Sub-Total Distribution Assets	**138,618,748**	**96,645,434**	**(41,973,314)**
General Plant			
1920 - Computer Equipment - Hardware	20,338	1,361	(18,977)
1925 - Computer Software	535,508	105,974	(429,534)
1980 - System Supervisory Equipment	4,354,818	1,538,204	(2,816,614)
Sub-Total General Plant	**4,910,664**	**1,645,539**	**(3,265,125)**
Capital Contributions			
1995 - Contributions and Grants	(13,149,069)	(12,207,471)	941,598
Sub-Total Capital Contributions	**(13,149,069)**	**(12,207,471)**	**941,598**
GROSS ASSET TOTAL	**134,056,897**	**89,439,316**	**(44,617,581)**

Overall decrease - 2014 converted to IFRS reporting – assets recorded at net as of January 1, 2014

ACCOUNT 1725 Poles & Fixtures ($149,147)

- IFRS Conversion – ($149,147)

ACCOUNT 1735 Underground Conduit ($115,846)

- IFRS Conversion – ($115,846)

ACCOUNT 1808 Building & Fixtures ($1,130,065)

- IFRS Conversion – ($1,374,919)
- Integrated building completed in 2013 – $244,854 – lifts, lockers, racking, partitions, projection screens, window shades.

ACCOUNT 1815 Transformer Station Equipment ($2,946,629)

- IFRS Conversion – ($3,564,552)
- Transmission station upgrades – $445,478 – TS1 Grounding and Fencing upgrades.
- TS1 Tie-Breaker rebuild – $158,517
- Various other immaterial items - $13,928

ACCOUNT 1820 Distribution Station Equipment ($5,423,515)

- IFRS Conversion – ($6,668,673)
- Upgrades to Distribution Stations – $521,526 - Sub 19 switch replacement and breaker rebuild, Battery Bank replacement, Fibre installation, relay replacement, Under Frequency Load Shedding relay installation Completion of distribution station (sub 10) upgrade – $674,216
- Various other immaterial items - $49,416

ACCOUNT 1830 Poles, Towers and Fixtures ($2,440,405)

- IFRS Conversion – ($4,722,373)
- New services and subdivisions - $400,455 – Northern Ave, Airport Rd., Allen's Side Road, Base Line, Bay St., Bruce St., Glengary Gate Subdivision, Great Northern Rd.,

Greenfield Dr., Industrial Park Cres., service to new high school, Pim St., Prince Lake Rd., McNabb St., Second Line E., Sunset Ridge Estates Subdivision

- Joint use projects - $1,010,215 – Work completed for the Bell Alliant Fiber to Home Project.
- Overhead renewal program - $631,378 - Replace deteriorated poles at various locations as required, White Oak Drive rear lot rebuild
- Forced overhead renewal (renewal due to storm damage, traffic accidents, etc.) - $145,135 – traffic accidents Queen St., Albert St., Sixth Line and unplanned miscellaneous capital replacements
- Various other immaterial items - $94,785

ACCOUNT 1835 Overhead Conductors and Devices ($4,646,502)

- IFRS Conversion – ($5,606,551)
- New services and subdivisions - $198,698 - Northern Ave, Airport Rd., Allen’s Side Road, Base Line, Bay St., Bruce St., Glengary Gate Subdivision, Great Northern Rd., Greenfield Dr., Industrial Park Cres., service to new high school, Pim St., Prince Lake Rd., McNabb St., Second Line E., Sunset Ridge Estates Subdivision, Old Goulais Bay Rd., SSM Golf Club.
- Overhead renewal program - $187,156 - White Oak Drive rear lot rebuild, unplanned miscellaneous capital replacements, replace deteriorated poles at various locations as required.
- Switch replacement program - $105,124 – defective switch replacement program.
- Insulator replacement program - $242,586 – Porcelain Insulator Replacement Program.
- Joint Use - $66,940 - Work completed for the Bell Alliant Fiber to Home Project.
- Restricted Wire $59,650 – replace restricted wire Farquhar/Anna Streets, Goulair Ave./Brookfield Blvd., Morrison/Anita Streets.
- Voltage Conversion - $45,055 – Pine Street.
- Various other immaterial items - $54,840

ACCOUNT 1840 Underground Conduit ($8,024,943)

- IFRS Conversion – ($8,307,080)
- New services and subdivisions - $175,379 – Central Creek Subdivision, Great Northern Road, Pine Shores Drive, Sherbrook Subdivision.
- City Projects - $73,276 – Queen Street road reconstruction, Albert Street West road reconstruction.
- Various other immaterial items - $33,481

ACCOUNT 1845 Underground Conductors and Devices ($8,143,502)

- IFRS Conversion – ($8,726,221)
- New services and subdivisions - $149,454 – Central Creek Subdivision, Fourth Line West, Bay Street, Bruce Street, Great Northern Road, Second Line West, Sherbrook Subdivision.
- City Projects - $348,298 – Albert Street West road reconstruction, Fort Creek Aqueduct.
- Underground Renewal Program - $43,641 – Woodward Ave. road reconstruction.
- Various other immaterial items - $41,326

ACCOUNT 1850 Line Transformers ($7,585,067)

- IFRS Conversion – ($8,231,001)
- New services and subdivisions - $345,555 – Allen side Road, Base Line Road, Sunnyside Beach, Central Creek Subdivision, new high school, Bay Street, Bruce Street, Huron Street, Great Northern Road, Pim Street, Sherbrook Subdivision, Second Line East, Town Line.
- Overhead renewal program - $122,899 – Miscellaneous unplanned capital replacements, White Oak Drive rear lot rebuild, replace deteriorated poles at various locations as required.
- Padmount Switch Gear Replacement Program - $99,486 – PMH Replacement Program.
- Various other immaterial items - $77,993

ACCOUNT 1855 Services - $96,318

- IFRS Conversion – ($445,240)
- New Services and Subdivisions - $527,136 – Northern Ave, Airport Rd., Allen's Side Road, Base Line, Bay St., Bruce St., Glengary Gate Subdivision, Great Northern Rd., Greenfield Dr., Industrial Park Cres., service to new high school, Pim St., Prince Lake Rd., McNabb St., Second Line E., Sunset Ridge Estates Subdivision, Old Goulais Bay Rd., SSM Golf Club.
- Various other immaterial items - $14,422

ACCOUNT 1860 Smart Meters ($1,730,283)

- IFRS Conversion – ($1,871,372)
- Meter installations - $139,712 – Install new electric meters.
- Various other immaterial items - $1,377

ACCOUNT 1925 Computer Software ($429,534)

- IFRS Conversion – ($429,534)

ACCOUNT 1980 System Supervisor Equipment ($2,816,614)

- IFRS Conversion – ($2,973,207)
- SCADA updates - $128,386 – UPS replacement, RTU replacements.
- Various other immaterial items - $28,207

ACCOUNT 1955 Contribution and Grants ($941,598)

- IFRS Conversion – ($1,987,329)
- Contributions and Grants – $1,045,731

2014 Actual vs. 2015 Actual

PUC Distribution experienced an overall increase in gross assets between 2014 Actual and 2015 Actual of $6,148,557, as can be seen in the following Table 2-7.

Table 2-7: 2014 Actual vs. 2015 Actual

Description	2014 Actuals	2015 Actuals	Variance between 2015 Actuals and 2014 Actuals
Reporting Basis	MIFRS	MIFRS	
Transmission Plant			
1706 - Land Rights	602,307	602,307	-
1725 - Poles and Fixtures	1,604,340	1,604,340	-
1730 - Overhead Conductors and Devices	63,894	63,894	-
1735 - Underground Conduit	870,021	870,021	-
1740 - Underground Conductors and Devices	215,252	215,252	-
Sub-Total Intanglible Plant	**3,355,814**	**3,355,814**	**-**
Distribution Assets			
1805 - Land	89,160	89,160	-
1806 - Land Rights	160,926	166,619	5,693
1808 - Buildings and Fixtures	24,869,821	24,936,353	66,532
1815 - Transformer Station Equipment - Normally Primary above 50 kV	6,109,645	6,209,828	100,183
1820 - Distribution Station Equipment - Normally Primary below 50 kV	9,057,776	9,922,834	865,058
1825 - Storage Battery Equipment	13,722	13,722	-
1830 - Poles, Towers and Fixtures	12,728,383	14,582,754	1,854,371
1835 - Overhead Conductors and Devices	9,305,779	10,456,639	1,150,860
1840 - Underground Conduit	2,828,168	3,167,642	339,474
1845 - Underground Conductors and Devices	12,019,819	12,805,713	785,894
1850 - Line Transformers	9,850,027	10,977,259	1,127,232
1855 - Services	5,002,146	5,360,047	357,901
1860 - Smart Meters	4,610,062	4,663,006	52,944
Sub-Total Distribution Assets	**96,645,434**	**103,351,576**	**6,706,142**
General Plant			
1920 - Computer Equipment - Hardware	1,361	-	(1,361)
1925 - Computer Software	105,974	-	(105,974)
1980 - System Supervisory Equipment	1,538,204	1,542,755	4,551
Sub-Total General Plant	**1,645,539**	**1,542,755**	**(102,784)**
Capital Contributions			
1995 - Contributions and Grants	(12,207,471)	(12,662,272)	(454,801)
Sub-Total Capital Contributions	**(12,207,471)**	**(12,662,272)**	**(454,801)**
GROSS ASSET TOTAL	**89,439,316**	**95,587,873**	**6,148,557**

ACCOUNT 1820 Distribution Station Equipment $865,058

- Sub 1 - $70,280
  - Replacement Breaker
  - MetroNet Existing Nodes Project
- Sub 10 - $174,344
  - Final Commissioning
  - Reconstruction and Circuit Configuration
- Sub 12 - $85,036
  - Utilization of Under Frequency Load Shedding Relay Installation
- Sub 13 - $31,848
  - Waterproofing
- Sub 15 - $42,947
  - Utilization of Under Frequency Load Shedding Relay Installation
- Sub 16 - $32,038
  - Reconstruction Planning
- Sub 19 - $161,864
  - Switch Replacement
  - Utilization of Under Frequency Load Shedding Relay Installation
- Sub 20 - $7,809
  - Ontera Fibre Installation
- Voltage conversion program - $257,569 – Voltage Quality Concerns and Regulator Installation
- Various other immaterial items - $1,323

ACCOUNT 1830 Poles, Towers and Fixtures $1,854,371

- Overhead renewal program - $644,093 - Replace deteriorated poles at various locations as required, Pine Street service relocation, replace Airport Road conductor, .

- Forced overhead renewal - (renewal due to storm damage, traffic accidents, equipment failure, etc.) - $107,906 – Traffic accidents on Douglas Ave., McNabb Street, Landslide Road, Trunk Road.
- Restricted wire replacement - $130,895 - Goulais to Brookfield Ave., Bayview area, Farquhar/Anna Streets, Langdon Road, Marconi/Cartier/Windsor Streets.
- Voltage conversion program (4kV to 12kV) - $646,133 - Pine Street, Elmwood/Blake Streets, Cameron/Stevens Streets, Allard Street.
- City projects - $63,781 – Town Line/Base Line bridge reconstruction. Upton Road reconstruction, John Street aqueduct reconstruction.
- New Services and Subdivisions - $162,331 – Service to Great Northern Road, Town Line Road, Metig Street, Trunk Road.
- Joint Use - $74,737 – Work completed for the Bell Alliant Fiber to Home Project.
- Various other immaterial items - $24,495

ACCOUNT 1835 Overhead Conductors and Devices $1,150,860

- Overhead renewal program - $310,734 – Replace deteriorated poles at various locations as required, replace Airport Road conductor and install overhead faulted circuit indicators at various locations.
- Restricted wire replacement - $90,998 – Goulais to Brookfield Ave., Bayview area, Farquhar/Anna Streets, Langdon Road, Marconi/Cartier/Windsor Streets.
- Voltage conversion program (4kV to 12 kV) – $336,557 – Pine Street, Elmwood/Blake Streets, Cameron/Stevens Streets.
- Switch replacement program - $99,881 – Defective switch replacement program.
- Insulator replacement program - $185,049 – Porcelain Insulator Replacement Program.
- Various other immaterial items - $127,641

ACCOUNT 1840 Underground Conduit $339,474

- City projects - $120,026 – Huron Street road reconstruction, John Street aqueduct reconstruction.
- Underground renewal program - $128,515 – Hudson to Huron Street.

- Voltage Conversion program (4kV to 12kV) - $51,597 – Norden Crescent.
- Various other immaterial items - $39,336

ACCOUNT 1845 Underground Conductors and Devices $785,894

- New services and subdivisions - $191,688 – John Street condominiums, North Street Ontario Finnish Rest Home Association expansion.
- City Projects - $379,454 - Huron Street road reconstruction, John Street aqueduct reconstruction.
- Underground renewal program - $145,482 - Hudson to Huron Street, miscellaneous unplanned capital replacements.
- Various other immaterial items - $69,270

ACCOUNT 1850 Line Transformers $1,127,232

- New services and subdivisions - $390,909 - North Street Ontario Finnish Rest Home Association expansion, Industrial Park Crescent service, Great Northern Road service, Northern Avenue service, Second Line West service, Queen Street East condominiums, Metig Street.
- Underground renewal program - $117,080 - Hudson to Huron Street, miscellaneous unplanned capital replacement. Forced Underground renewal - $132,840 – Replace leaking transformer on Albert Street, Fish Hatchery Road, Cambridge Place, Queen Street East, Airport Road.
- Restricted wire program - $36,008 - Goulais to Brookfield Ave., Farquhar/Anna Streets, Langdon Road.
- Voltage Conversion Program - $299,308 - Pine Street, Elmwood/Blake Streets, Cameron/Stevens Streets, Allard Street.
- Padmount Switch Gear Replacement Program - $49,303 – PMH Replacement Program.
- Various other immaterial items - $355

ACCOUNT 1855 Services $357,901

- New services and subdivisions - $357,546 – Customer Demand residential services, Customer Demand commercial services.
- Various other immaterial items - $101,784

ACCOUNT 1955 Contribution and Grants $454,801

- New services and subdivisions

2015 Actual vs. 2016 Actual

PUC Distribution experienced an overall increase in gross assets between 2015 Actual and 2016 Actual of $5,538,354, as can be seen in the following Table 2-8.

Table 2-8: 2015 Actual vs. 2016 Actual

Description	2015 Actuals	2016 Actuals	Variance between 2016 Actuals and 2015 Actuals
Reporting Basis	MIFRS	MIFRS	
Transmission Plant			
1706 - Land Rights	602,307	602,307	-
1725 - Poles and Fixtures	1,604,340	1,604,340	-
1730 - Overhead Conductors and Devices	63,894	63,894	-
1735 - Underground Conduit	870,021	870,021	-
1740 - Underground Conductors and Devices	215,252	215,252	-
Sub-Total Intanglible Plant	**3,355,814**	**3,355,814**	**-**
Distribution Assets			
1805 - Land	89,160	89,160	-
1806 - Land Rights	166,619	173,683	7,064
1808 - Buildings and Fixtures	24,936,353	25,018,983	82,630
1815 - Transformer Station Equipment - Normally Primary above 50 kV	6,209,828	6,485,565	275,737
1820 - Distribution Station Equipment - Normally Primary below 50 kV	9,922,834	10,199,773	276,939
1825 - Storage Battery Equipment	13,722	13,722	-
1830 - Poles, Towers and Fixtures	14,582,754	16,184,674	1,601,920
1835 - Overhead Conductors and Devices	10,456,639	11,734,957	1,278,318
1840 - Underground Conduit	3,167,642	3,544,783	377,141
1845 - Underground Conductors and Devices	12,805,713	13,139,135	333,422
1850 - Line Transformers	10,977,259	12,256,441	1,279,182
1855 - Services	5,360,047	5,709,600	349,553
1860 - Smart Meters	4,663,006	4,746,659	83,653
Sub-Total Distribution Assets	**103,351,576**	**109,297,135**	**5,945,559**
General Plant			
1920 - Computer Equipment - Hardware	-	-	-
1980 - System Supervisory Equipment	1,542,755	1,585,822	43,067
Sub-Total General Plant	**1,542,755**	**1,585,822**	**43,067**
Capital Contributions			
1995 - Contributions and Grants	(12,662,272)	(13,112,544)	(450,272)
Sub-Total Capital Contributions	**(12,662,272)**	**(13,112,544)**	**(450,272)**
GROSS ASSET TOTAL	**95,587,873**	**101,126,227**	**5,538,354**

ACCOUNT 1815 Transformer Station Equipment $275,737

- Transmission station upgrades - $70,979 – DC Battery and Charger System Replacement
- Energy storage project - $203,253 – Service to 7MW Storage Facility
- Various other immaterial items - $1,505

ACCOUNT 1820 Distribution Station Equipment $276,939

- Sub 1 - $6,853
    - RTU Replacement
- Sub 11 - $117,421
    - Conductor replacement
- Sub 16 - $35,585
    - Reconstruction Planning
- Sub 18 - $83,104
    - Substation relay replacement
    - Under Frequency Load Shedding Relay Installation
- Sub 19 - $71,099
    - New service to Station
    - Battery and charger system replacement
- Sub 20 - $31,833
    - RTU replacement
- Voltage conversion program – ($96,854) – Voltage Quality Concerns and Regulator installation
- Various other immaterial items - $27,898

ACCOUNT 1830 Poles, Towers and Fixtures $1,601,920

- New services and subdivisions - $274,915 – Service to Allen Side Road, Bittern Street, Dundas Street, Eastside Subdivisions, Grand Blvd., Maki Road, Silver Birch Apartments.

- Overhead renewal program - $242,031 - Replace deteriorated poles at various locations as required, replace pole line Pim Street, Red Rock voltage regulator, voltage regulator installations.
- Forced Overhead renewal (renewal due to storm damage, traffic accidents, etc.) - $155,818 – Traffic accidents on Malabar Drive, McNabb Street, Northern Ave., Peoples Road (2), Second Line East, Black Road, Korah Road, St. Georges Ave., and unplanned miscellaneous capital replacements.
- Restricted wire program - $372,010 - Bayview area, Chlebus/Norden/Moluch Streets, Marconi/Cartier/Windsor Streets.
- Voltage Conversion Program - $371,099 – Blake Street, Grand Area, Caledon/Leslie/Albion Streets.
- Various other immaterial items - $186,047

ACCOUNT 1835 Overhead Conductors and Devices $1,278,318

- New services and subdivisions - $101,891 - Service to Allen Side Road, Bittern Street, Dundas Street, Base Line Road, Queen Street East, Yates Ave., Trunk Road, Nokomis Beach, John Street.
- Overhead renewal program - $178,694 - Replace pole line Pim Street, Red Rock voltage regulator, voltage regulator installation.
- Forced Overhead renewal (renewal due to storm damage, traffic accidents, etc.) - $42,914 - Traffic accidents on Malabar Drive, Northern Ave., Peoples Road (2), Second Line East, Moss Road, miscellaneous unplanned capital replacements.
- Restricted wire program - $371,776 – Edison Street, Marconi/Cartier/Windsor Streets, Bayview area, Chlebus/Norden/Moluch Streets.
- Voltage Conversion Program - $457,601 - Blake Street, Grand Area, Caledon/Leslie/Albion Streets, Chapple Street, Elmwood Ave.
- Various other immaterial items - $125,442

ACCOUNT 1840 Underground Conduit $377,141

- City Projects - $86,962 - Gore Street road reconstruction, John Street aqueduct reconstruction.
- Underground renewal program - $75,056 – Replace underground vaults at various locations.
- Voltage Conversion Program - $163,259 – Blake Street, Grand Area, Charlotte Ave., Willow Ave.
- Various other immaterial items - $51,864

ACCOUNT 1845 Underground Conductors and Devices $333,422

- New services and subdivisions - $94,176 - Service to Allen Side Road, Eastside Subdivisions, Queen Street East Condominiums, Second Line East, Silver Birch Apartments.
- City Projects - $41,381 – Huron Street road reconstruction.
- Underground renewal program - $149,431 – Charlotte Ave.
- Various other immaterial items - $48,444

ACCOUNT 1850 Line Transformers $1,279,182

- New services and subdivisions - $279,567 - Service to Allen Side Road, Dundas Street, Base Line Road, Queen Street East, Trunk Road, Nokomis Beach, John Street, Second Line West, Airport Road, Eastside Subdivision, Elmwood Ave., Grand Blvd., Great Northern Road, Etienne Brule site.
- Overhead renewal program - $128, 906 – Elmwood and Blake Ave., Red Rock voltage regulator, voltage other regulator installation.
- Underground renewal program - $114,163 - Charlotte Ave.
- Forced overhead renewal (renewal due to storm damage, traffic accidents, etc.) - $72.397 – Miscellaneous unplanned capital replacements, Muriel Drive replacing a leaking transformer.

- Forced underground renewal - $236,062 – Replace leaking transformers on Connaught Street, Doncaster Road, Palomino Drive, Pinto Drive, Queen Street East, Sackville Road, Second Line East, Sussex Road, Trunk Road and miscellaneous unplanned capital replacements.
- Restricted wire program - $133,426 - Marconi/Cartier/Windsor Streets, Bayview area, Chlebus/Norden/Moluch Streets.
- Voltage conversion program - $149,900 - Blake Street, Grand Area, Caledon/Leslie/Albion Streets, Elmwood Ave.
- Padmount Switch Gear Replacement Program - $87,999 - PMH Replacement Program.
- Various other immaterial items - $76,762

ACCOUNT 1855 Services $349,553

- New services and subdivisions - $347,857 - Customer Demand residential services, Customer Demand commercial services.
- Various other immaterial items - $1,696

ACCOUNT 1955 Contribution and Grants $450,272

- New services and subdivision

2016 Actual vs. 2017 Bridge

PUC Distribution’s overall increase in gross assets between 2016 Actual and 2017 Bridge is $4,681,921, as can be seen in the following Table 2-9.

Table 2-9: 2016 Actual vs. 2017 Bridge

Description	2016 Actuals	2017 Bridge	Variance between 2017 Bridge and 2016 Actuals
Reporting Basis	MIFRS	MIFRS	
Transmission Plant			
1706 - Land Rights	602,307	602,307	-
1725 - Poles and Fixtures	1,604,340	1,604,340	-
1730 - Overhead Conductors and Devices	63,894	63,894	-
1735 - Underground Conduit	870,021	870,021	-
1740 - Underground Conductors and Devices	215,252	215,252	-
Sub-Total Intanglible Plant	**3,355,814**	**3,355,814**	-
Distribution Assets			
1805 - Land	89,160	89,160	-
1806 - Land Rights	173,683	176,129	2,446
1808 - Buildings and Fixtures	25,018,983	25,018,983	-
1815 - Transformer Station Equipment - Normally Primary above 50 kV	6,485,565	6,928,216	442,651
1820 - Distribution Station Equipment - Normally Primary below 50 kV	10,199,773	10,836,670	636,897
1825 - Storage Battery Equipment	13,722	13,722	-
1830 - Poles, Towers and Fixtures	16,184,674	17,565,549	1,380,875
1835 - Overhead Conductors and Devices	11,734,957	12,608,394	873,437
1840 - Underground Conduit	3,544,783	3,806,872	262,089
1845 - Underground Conductors and Devices	13,139,135	13,524,716	385,581
1850 - Line Transformers	12,256,441	13,307,214	1,050,773
1855 - Services	5,709,600	6,134,778	425,178
1860 - Smart Meters	4,746,659	4,960,527	213,868
Sub-Total Distribution Assets	**109,297,135**	**114,970,930**	**5,673,795**
General Plant			
1920 - Computer Equipment - Hardware	-	-	-
1980 - System Supervisory Equipment	1,585,822	1,590,008	4,186
Sub-Total General Plant	**1,585,822**	**1,590,008**	**4,186**
Capital Contributions			
1995 - Contributions and Grants	(13,112,544)	(14,108,604)	(996,060)
Sub-Total Capital Contributions	**(13,112,544)**	**(14,108,604)**	**(996,060)**
GROSS ASSET TOTAL	**101,126,227**	**105,808,148**	**4,681,921**

ACCOUNT 1815 Transformer Station Equipment $442,651

- Energy storage project - $425,000 – Service to 7MW Storage Facility
- Various other immaterial items - $17,651

ACCOUNT 1820 Distribution Station Equipment $636,897

- Distribution station (sub 16) rebuild - $73,445 – engineering design
- Distribution station upgrades - $489,365 – Battery bank replacements/additions, breaker upgrades, relay upgrades, RTU upgrades.
- Voltage conversion program - $86,788 – Willoughby Street, Chapple Ave., Allard Street, McNabb Street, Pine Street, Elizabeth Street, Moluch Street, Wellington Street East, Queen Street East.
- Various other immaterial items – ($12,701)

ACCOUNT 1830 Poles, Towers and Fixtures $1,380,875

- New services and subdivisions - $229,541 – Queensgate Greens Subdivision, Greenfield Subdivision, Dell Subdivision extension, miscellaneous service requests.
- Overhead renewal program - $238,631 – Replace deteriorated wood poles, McNabb/McDonald roadway connection.
- Forced Overhead renewal - $177,116 – (renewal due to storm damage, traffic accidents, , equipment failures, etc.)
- Restricted wire program - $274,814 – Edison/Nichol/Wilding Streets, Grace Street, Point Des Chenes, Forest/Ontario/Upton/Labelle/The Drive Streets.
- Voltage Conversion Program - $348,464 – Willoughby Street, Chapple Ave., Allard Street, McNabb Street, Pine Street, Elizabeth Street, Moluch Street, Wellington Street East, Queen Street East.
- Various other immaterial items – $112,309

ACCOUNT 1835 Overhead Conductors and Devices $873,437

- New services and subdivisions - $89,737 – Queensgate Greens Subdivision, Greenfield Subdivision, Dell Subdivision extension, miscellaneous service requests.
- Overhead renewal program - $105,284 – Replace deteriorated wood poles, McNabb/McDonald roadway connection.
- Forced Overhead renewal - $52,339 – (renewal due to storm damage, traffic accidents, , equipment failures, etc.
- Restricted wire program - $284,386 – Edison/Nichol/Wilding Streets, Grace Street, Point Des Chenes, Forest/Ontario/Upton/Labelle/The Drive Streets.
- Voltage Conversion Program - $291,882 – Willoughby Street, Chapple Ave., Allard Street, McNabb Street, Pine Street, Elizabeth Street, Moluch Street, Wellington Street East, Queen Street East.
- Various other immaterial items – $49,808

ACCOUNT 1840 Underground Conduit $262,089

- New services and subdivisions - $75,874 – Queensgate Greens Subdivision, Greenfield Subdivision, Dell Subdivision extension, miscellaneous service requests.
- City Projects - $48,705 – Black Road, John Street Aqueduct, Sackville Road.
- Underground renewal program - $56,141
- Voltage Conversion Program - $72,311 – Willoughby Street, Chapple Ave., Allard Street, McNabb Street, Pine Street, Elizabeth Street, Moluch Street, Wellington Street East, Queen Street East.
- Various other immaterial items – $9,057

ACCOUNT 1845 Underground Conductors and Devices $385,581

- New services and subdivisions - $119,734 – Queensgate Greens Subdivision, Greenfield Subdivision, Dell Subdivision extension, miscellaneous service requests.
- City Projects - $160,597 – Black Road, John Street Aqueduct, Sackville Road.
- Underground renewal program - $69,928 – Vault replacements,

- Various other immaterial items – $35,321

ACCOUNT 1850 Line Transformers $1,050,773

- New services and subdivisions - $267,636 – Queensgate Greens Subdivision, Greenfield Subdivision, Dell Subdivision extension, miscellaneous service requests.
- Forced underground renewal - $238,336 (renewal due to storm damage, traffic accidents, , equipment failures, etc.
- Restricted wire program - $78,066 – Edison/Nichol/Wilding Streets, Grace Street, Point Des Chenes, Forest/Ontario/Upton/Labelle/The Drive Streets.
- Distribution station (sub 16) rebuild - $162,362 - Engineering design
- Voltage conversion program - $157,654 – Willoughby Street, Chapple Ave., Allard Street, McNabb Street, Pine Street, Elizabeth Street, Moluch Street, Wellington Street East, Queen Street East.
- Overhead Renewal Program - $42,844 – Replace deteriorated wood poles, McNabb/McDonald roadway connection.
- Underground Renewal Program - $47,728 – Vault replacements,
- Forced Overhead Renewal - $49,192 – (renewal due to storm damage, traffic accidents, equipment failures, etc.
- Various other immaterial items – $69,055

ACCOUNT 1855 Services $425,178

- New services and subdivisions - $419,376 – Queensgate Greens Subdivision, Greenfield Subdivision, Dell Subdivision extension, miscellaneous service requests.
- Various other immaterial items – $5,803

ACCOUNT 1860 Smart Meters $213,868

- Meter installations - $205,105 – Install new electric meters.
- Various other immaterial items – $8,763

ACCOUNT 1955 Contribution and Grants $ 996,060

- New services and subdivision
- Energy storage project

2017 Bridge vs. 2018 Test

PUC Distribution's overall increase in gross assets between 2017 Bridge and 2018 Test is $5,358,355, as can be seen in the following Table 2-10.

1 **Table 2-10: 2017 Bridge vs. 2018 Test**

2

Description	2017 Bridge	2018 Test	Variance between 2018 Test and 2017 Bridge
Reporting Basis	MIFRS	MIFRS	
Transmission Plant			
1706 - Land Rights	602,307	602,307	-
1725 - Poles and Fixtures	1,604,340	1,604,340	-
1730 - Overhead Conductors and Devices	63,894	63,894	-
1735 - Underground Conduit	870,021	870,021	-
1740 - Underground Conductors and Devices	215,252	215,252	-
Sub-Total Intanglible Plant	**3,355,814**	**3,355,814**	**-**
Distribution Assets			
1805 - Land	89,160	89,160	-
1806 - Land Rights	176,129	177,750	1,621
1808 - Buildings and Fixtures	25,018,983	25,082,082	63,099
1815 - Transformer Station Equipment - Normally Primary above 50 kV	6,928,216	7,050,995	122,779
1820 - Distribution Station Equipment - Normally Primary below 50 kV	10,836,670	11,362,705	526,035
1825 - Storage Battery Equipment	13,722	13,722	-
1830 - Poles, Towers and Fixtures	17,565,549	19,152,541	1,586,992
1835 - Overhead Conductors and Devices	12,608,394	13,643,112	1,034,718
1840 - Underground Conduit	3,806,872	4,021,502	214,630
1845 - Underground Conductors and Devices	13,524,716	13,877,001	352,285
1850 - Line Transformers	13,307,214	14,580,125	1,272,911
1855 - Services	6,134,778	6,592,261	457,483
1860 - Smart Meters	4,960,527	5,106,563	146,036
Sub-Total Distribution Assets	**114,970,930**	**120,749,519**	**5,778,589**
General Plant			
1920 - Computer Equipment - Hardware	-	-	-
1980 - System Supervisory Equipment	1,590,008	1,619,774	29,766
Sub-Total General Plant	**1,590,008**	**1,619,774**	**29,766**
Capital Contributions			
1995 - Contributions and Grants	(14,108,604)	(14,558,604)	(450,000)
Sub-Total Capital Contributions	**(14,108,604)**	**(14,558,604)**	**(450,000)**
GROSS ASSET TOTAL	**105,808,148**	**111,166,503**	**5,358,355**

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ACCOUNT 1815 Transformer Station Equipment $122,779

- Transmission station upgrades - $105,463 – Replacement of failed equipment, RTU replacement.
- Various other immaterial items - $17,616

ACCOUNT 1820 Distribution Station Equipment $526,035

- Distribution station (sub 16) rebuild - $121,065 - Engineering design.
- Distribution station upgrades - $308,987 – Battery bank replacements/additions, SCADA and communication equipment renewal, breaker upgrades, relay upgrades, RTU upgrades.
- Voltage conversion program - $81,568 – Moluch Street, McDonald Street, Laronde Ave., Koprash Court.
- Various other immaterial items - $14,415

ACCOUNT 1830 Poles, Towers and Fixtures $1,586,992

- New services and subdivisions - $247,298 - Miscellaneous subdivisions and service requests.
- Joint use projects - $123,906 – Miscellaneous communication company requests.
- Overhead renewal program - $256,256 – Replace deteriorated wood poles.
- Forced Overhead renewal - $190,818 – (renewal due to storm damage, traffic accidents, , equipment failures, etc.)
- Restricted wire program - $418,175 – Carpin Beach Road, Leigh’s Bay Road, Red Pine Drive, Wallace Terrace.
- Voltage Conversion Program - $327,507 – Moluch Street, McDonald Street, .
- Various other immaterial items - $23,032

ACCOUNT 1835 Overhead Conductors and Devices $1,034,718

- New services and subdivisions - $96,679 - Miscellaneous subdivisions and service requests (Castle Heights Subdivision, Greenfield Subdivision, Eatside Subdivision).

- Overhead renewal program - $113,061 – Replace deteriorated wood poles.
- Forced Overhead renewal - $56,388 – (renewal due to storm damage, traffic accidents, , equipment failures, etc.)
- Restricted wire program - $432,741 – Carpin Beach Road, Leigh’s Bay Road, Red Pine Drive, Wallace Terrace.
- Voltage Conversion Program - $274,327 – Moluch Street, McDonald Street,
- Various other immaterial items - $61,522

ACCOUNT 1840 Underground Conduit $214,630

- New services and subdivisions - $81,744 - Miscellaneous subdivisions and service requests (Castle Heights Subdivision, Greenfield Subdivision, Eatside Subdivision)..
- City Projects - $55,971 – Black Road reconstruction, Simpson St., Bruce St., Wellington St. Aqueduct and Central Street Aqueduct.
- Voltage Conversion Program - $67,962 – Moluch Street, McDonald Street, Laronde Ave., Koprash Court.
- Various other immaterial items - $8,952

ACCOUNT 1845 Underground Conductors and Devices $352,285

- New services and subdivisions - $128,997 - Miscellaneous subdivisions and service requests (Castle Heights Subdivision, Greenfield Subdivision, Eatside Subdivision)..
- City projects - $184,556 – Black Road reconstruction, Simpson St., Bruce St., Wellington St. Aqueduct and Central Street Aqueduct.
- Various other immaterial items - $38,731

ACCOUNT 1850 Line Transformers $1,272,911

- New services and subdivisions - $288,341 - Miscellaneous subdivisions and service requests (Castle Heights Subdivision, Greenfield Subdivision, Eatside Subdivision)..
- Restricted wire program - $118,790 – Carpin Beach Road, Leigh’s Bay Road, Red Pine Drive, Wallace Terrace.
- Distribution station (sub 16) rebuild - $267,633 - Engineering design

- Voltage conversion program - $148,173 – Moluch Street, McDonald Street, Laronde Ave., Koprash Court.
- Overhead Renewal Program - $46,008 – Replace deteriorated wood poles.
- Forced Overhead Renewal - $52,998 – (renewal due to storm damage, traffic accidents, , equipment failures, etc.)
- Forced Underground Renewal - $288,871 – (renewal due to storm damage, traffic accidents, , equipment failures, etc.)
- Various other immaterial items - $62,097

ACCOUNT 1855 Services $457,483

- New services and subdivisions - $451,820 - Miscellaneous subdivisions and service requests (Castle Heights Subdivision, Greenfield Subdivision, Eatside Subdivision)..
- Various other immaterial items - $56,064

ACCOUNT 1860 Smart Meters $146,036

- Meter installations - $136,601 – Install new electric meters.
- Various other immaterial items - $9,434

ACCOUNT 1955 Contribution and Grants $450,000

- New services and subdivision

Incremental Capital Module Adjustments

PUC Distribution does not have any Incremental Capital Module Adjustments.

2.2.1.3 Allowance for Working Capital

Allowance Factor Overview

In accordance with the Filing Requirements and in a letter dated June 3, 2015, the Board updated its policy for the calculation of the allowance for working capital. As outlined in both documents, distributors may take one of two approaches for the calculation of its allowance for working capital:

1. Use a default allowance approach; or
2. The filing of a lead/lag study.

PUC Distribution has used the default allowance of 7.5% for the 2018 Test Year in this Application, in accordance with the Filing Requirements.

Working Capital Allowance

PUC Distribution is proposing a working capital allowance of $6,885,803 as shown in Table 2-11 below:

Table 2-11: Working Capital Allowance

Distribution Expenses	2018 Test Year
Distribution Expenses - Operations	$ 4,026,057
Distribution Expenses - Maintenance	$ 2,186,573
Billing and Collecting	$ 1,575,376
Commuity Relations	$ 618,800
Administrative and General Expenses	$ 3,480,028
Donations - LEAP	$ 24,000
Taxes other than Income Taxes	$ 45,000
Total Eligible Distribution Expenses	**$ 11,955,834**
Power Supply Expenses	$ 79,854,870
Total Working Capital Expenses	**$ 91,810,704**
Working Capital Allowance @ 7.5%	**$ 6,885,803**

In Table 2-12 below, PUC Distribution has shown the calculation of the Power Supply Expense as mention in Table 2-11: Working Capital Allowance above.

Table 2-12: Power Supply Expense 2018 Test Year

Power Supply Expense 2018 Test Year			
Commodity	**Forecasted kWh/kW**	**Rate**	**Amount**
Power Purhased RPP	483,396,591	$ 0.10721	$ 51,822,532
Power Purhased Non-RPP	190,399,540	$ 0.10695	$ 20,363,802
			$ 72,186,334
Transmission Network	**Forecasted kWh/kW**	**Rate**	**Amount**
Residential	310,650,128	$ 0.0059	$ 1,832,836
General Service < 50 kW	98,856,928	$ 0.0055	$ 546,679
General Service 50 kW to 4,999 kW	624,500	$ 2.2455	$ 1,402,315
Sentinel Lights	616	$ 1.7021	$ 1,048
Street Lights	7,076	$ 1.6935	$ 11,983
Unmetered Scattered Load	1,233,427	$ 0.0055	$ 6,784
			$ 3,801,645
Wholesale Market Service Charge	**Forecasted kWh/kW**	**Rate**	**Amount**
WMS	673,796,131	$ 0.0036	**$ 2,425,666**
Rural Rate Assistance	**Forecasted kWh/kW**	**Rate**	**Amount**
RRRP	673,796,131	$ 0.0021	**$ 1,414,972**
Smart Meter Entity Charge	**Customers**	**Rate**	**Amount**
	33,232	$ 0.79	**$ 26,253**
Total Power Supply Expense			**$ 79,854,870**

2.2.2 Capital Expenditures

Planning Overview

In accordance with the Filing Requirements, PUC Distribution is filing its Distribution System Plan (“DSP”) as a stand-alone document in Appendix 2 to this Exhibit. PUC Distribution has organized the information contained in the DSP using the headings indicated in Chapter 5 of the Board’s Filing Requirements for Electricity Distribution and Transmission Applications, Consolidated Distribution System Plan Filing Requirements dated March 28. 2013. The DSP incorporates matters pertaining to asset management, regional planning and renewable energy generation.

The four categories of system investments have been addressed in PUC Distribution's capital expenditure plan, including System Access, System Renewal, System Service and General Plant. PUC has provided historical spending by material capital projects for the 2013 Actual, 2014 Actual, 2015 Actual, 2016 Actual, 2017 Bridge and 2018 Test years.

Analysis of Capital Expenditures

Table 2-13 below provides a summary of capital expenditures for the historical years, 2012 through 2016. This table can be found in Appendix 3 and is consistent with Board Appendix 2-AB.

Table 2-13: Historical Capital Expenditure Summary

CATEGORY	Historical Period (previous plan[1] & actual)														
	2012			2013			2014			2015			2016		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access	1,132	7,938	601.1%	1,069	2,310	116.1%	2,957	2,532	-14.4%	1,265	1,549	22.4%	1,215	1,212	-0.2%
System Renewal	6,043	4,821	-20.2%	6,525	6,083	-6.8%	3,813	3,754	-1.6%	4,753	4,640	-2.4%	4,543	4,244	-6.6%
System Service	-	-	--	-	-	--	-	-	--	-	-	--	-	-	--
General Plant	17,803	23,269	30.7%	1,314	2,028	54.4%	175	376	114.1%	69	67	-3.1%	-	83	--
TOTAL EXPENDITURE	24,978	36,028	44.2%	8,907	10,421	17.0%	6,946	6,661	-4.1%	6,087	6,256	2.8%	5,758	5,538	-3.8%
System O&M	$ 6,259	$ 5,853	-6.5%	$ 6,154	$ 5,992	-2.6%	$ 5,530	$ 5,773	4.4%	$ 5,819	$ 5,978	2.7%	$ 6,201	$ 5,978	-3.6%

Planned vs. Actual Variances

2012 Planned vs. Actual

In 2012, the actual expenditure in the "System Access" category exceeded the budget by over $6.8million. This variation is related to the timing of the capitalization of smart meters. Although the installation work was physically substantially complete at the end of 2010, the costs were not capitalized until 2012 as outlined in the 2013 Cost of Service Application.

The actual expenditure in the “System Renewal” category was below budget by approximately $1.2 million. This was primarily due to delays experienced during the reconstruction of the 12kV substation (Sub 10). Engineering resource constraints, equipment deliveries and poor winter weather were primary contributors to pushing completion of this project out into 2013.

The actual expenditure in “General Plant” category exceeded the budget by over $5.5million. This variation in expenditure is related to the construction of the new office building, which was budgeted in 2011, but most of the work on it was completed in 2012.

2013 Planned vs. Actual

The actual expenditure in the “System Access” category exceeded the budget by over $1.2 million. This variance was primarily a result of the utility having to support a substantially large and unplanned for joint-use project for one of the major telecommunications companies sharing space on its overhead infrastructure. A significant volume of make-ready work was completed to allow them to attach their fiber optic cables on PUC overhead poles. The scale of the project also led to significant resource constraints so that many projects in the “System Renewal” were not completed. In that area for 2013, a $440 thousand variance below budget was recorded.

The actual expenditure in the “General Plant” category exceeded the budget by approximately $720 thousand. This variation in expenditure was solely related to the construction of the new office building referred to above in 2012 for which a number of small remaining outstanding items and deficiencies were not completed until early 2013.

2014 Planned vs. Actual

In 2014, the variation in overall capital expenditure from the budget was insignificantly small.

The actual expenditure in the “System Access” category was less than the budgeted amount by about 14%. This was attributable to a combination of two factors. Firstly, continuation of the large joint-use fibre project (that was mentioned in the section above) started in 2013 was budgeted for in 2014. However, as the project progressed, circumstances changed for the telecommunications company and they canceled the project at the approximate half-way point. This had the effect for PUC Distribution of being significantly underspent on associated make-ready work. The second lesser impacting, but mitigating factor was higher than anticipated customer demand and the last-minute addition to City reconstruction projects that required additional infrastructure relocation by the PUC Distribution.

In the "System Renewal" category, the actual expenditure was less than the budgeted amount by 2%.

The actual expenditure in the "General Plant" category exceeded the budget by approximately $200,000. This variation in expenditure is related to finalizing the costs related to the newly constructed office building that were not anticipated at the time of budgeting.

2015 Planned vs. Actual

In 2015, the overall capital expenditure exceeded the budget by approximately 3% and this variation was caused by an overrun of $285,000 in the "System Access" category. PUC Distribution was required to relocate lines to facilitate municipal projects for which information was not available in advance of preparing the 2015 budget.

2016 Planned vs. Actual

In 2016, the variation in the overall capital expenditure from the budget was small – less than 4% of budget.

The actual expenditure in the "System Access" category was less than the budgeted amount by about $3,000 and within 1% of budget.

In the “System Renewal” category, the actual expenditure was less than the budgeted amount by about 7% due to a combination of compounding factors:

- Cost recoverable infrastructure upgrades at one of the transformer stations to facilitate the connection of a 7MWh energy storage facility constrained Engineering resources resulting in less than planned progress on a 12kV station rebuild design for Substation 16.
- Increased expenditures in unplanned overhead and underground work due to equipment failures, primarily leaking transformers and deteriorated poles that resulted in premature failures that required immediate attention.

The Forecasted Capital Expenditure is presented in Table 2-14 below.

Table 2-14: Forecasted Capital Expenditure Summary

CATEGORY	**Forecast Period** (planned)					
	2017	2018	2019	2020	2021	2022
	$ '000					
System Access	1,271	1,511	1,615	2,086	1,604	1,560
System Renewal	3,372	3,761	6,906	3,296	4,533	7,093
System Service	38	-	-	-	-	-
General Plant	-	86	55	62	60	55
TOTAL EXPENDITURE	4,682	5,358	8,576	5,445	6,197	8,708
System O&M	$ 5,857	$ 6,213	$ 6,337	$ 6,464	$ 6,593	$ 6,725

Variance Analysis by Spending Category

The following variance analysis has been prepared based on PUC Distribution’s materiality threshold of $110,400, per the materiality calculation noted in Exhibit 1 of this Application. Expenditures in the System Access category experience variations – customer growth in PUC Distribution’s service territory is low and there are sporadic variations in the number of requests received for new services from one year to the next, which results in significant variations in year over year spending in this category. Similarly, the amount of work related to line relocates varies from year to year due to variations in demand for such services.

2012 Actual versus 2013 Actual Capital Expenditure Variances

PUC Distribution experienced an overall decrease in capital expenditures of $25,607,204 from 2012 Actual results to 2013 Actual results summarized in Table 2-15 below.

Table 2-15: 2012 Actual versus 2013 Actual Capital Expenditure Variances

Category	2012 Actual	2013 Actual	Variance 2012 to 2013
System Access	7,938,036.00	2,310,000.00	**(5,628,036.00)**
System Renewal	4,821,060.00	6,082,921.00	**1,261,861.00**
Systerm Service	-	-	-
General Plant	23,269,373.00	2,028,344.00	**(21,241,029.00)**
Total Expenditure	**36,028,469.00**	**10,421,265.00**	**(25,607,204.00)**

System Access

- 2012 Smart meter regulatory entry $6,467,554.80
- Increase in joint use work in 2013 and 2014 – communication company – overhead support structure work
- Increased new subdivision work

System Renewal

- Includes cost of substation rebuild (sub 10)

General Plant

- Majority of work on new integrated building done in 2012 ($22,927,674.27) – completed in 2013

2013 Actual versus 2014 Actual Capital Expenditure Variances

PUC Distribution experienced an overall decrease in capital expenditures of $3,760,217 from 2013 Actual results to 2014 Actual results summarized in Table 2-16 below.

Table 2-16: 2013 Actual versus 2014 Actual Capital Expenditure Variances

Category	2013 Actual	2014 Actual	Variance 2013 to 2014
System Access	2,310,000.00	2,531,753.00	**221,753.00**
System Renewal	6,082,921.00	3,753,602.00	**(2,329,319.00)**
Systerm Service	-	-	**-**
General Plant	2,028,344.00	375,693.00	**(1,652,651.00)**
Total Expenditure	**10,421,265.00**	**6,661,048.00**	**(3,760,217.00)**

System Access

Increase in joint use work in 2013 and 2014 – communication company – overhead support structure work

Increased new subdivision work

System Renewal

- Substation rebuild (sub 10) occurred in 2013

System Service

In 2014, PUC Distribution experienced no change in System Service capital expenditures.

General Plant

- New integrated building substantially completed in 2013 – Yard work and miscellaneous work done in 2014 (roadway paving, garage canopy, front steps, etc.

2014 Actual versus 2015 Actual Capital Expenditure Variances

PUC Distribution experienced an overall decrease in capital expenditures of $405,157 from 2014 Actual results to 2015 Actual results summarized in Table 2-17 below.

Table 2-17: 2014 Actual versus 2015 Actual Capital Expenditure Variances

Category	2014 Actual	2015 Actual	Variance 2014 to 2015
System Access	2,531,753.00	1,549,411.00	**(982,342.00)**
System Renewal	3,753,602.00	4,639,948.00	**886,346.00**
Systerm Service	-	-	**-**
General Plant	375,693.00	66,532.00	**(309,161.00)**
Total Expenditure	**6,661,048.00**	**6,255,891.00**	**(405,157.00)**

System Access

- Increase in joint use work in 2013 and 2014 – communication company – overhead support structure work – program did not continue in 2015

System Renewal

- Crews were able to resume System Renewal work with the discontinuance of the third party telecommunication project

System Service

In 2015, PUC Distribution experienced no change in System Service capital expenditures.

General Plant

- work completed on the new building grounds in 2014

2015 Actual versus 2016 Actual Capital Expenditure Variances

PUC Distribution experienced an overall decrease in capital expenditures of $717,536 from 2015 Actual results to 2016 Actual results summarized in Table 2-18 below.

Table 2-18: 2015 Actual versus 2016 Actual Capital Expenditure Variances

Category	2015 Actual	2016 Actual	Variance 2015 to 2016
System Access	1,549,411.00	1,211,917.00	**(337,494.00)**
System Renewal	4,639,948.00	4,243,808.00	**(396,140.00)**
Systerm Service	-	-	**-**
General Plant	66,532.00	82,630.00	**16,098.00**
Total Expenditure	**6,255,891.00**	**5,538,355.00**	**(717,536.00)**

System Access

- Reduced new subdivisions & service upgrades in 2016
- Reduction in work related to City projects

System Renewal

- Insulator replacement program completed in 2015
- Sub 10 work completed in 2015

System Service

In 2016, PUC Distribution experienced no change in System Service capital expenditures.

General Plant

In 2016, PUC Distribution experienced no material change in General Plant capital expenditures.

2016 Actual versus 2017 Bridge Year Capital Expenditure Variances

PUC Distribution experienced an overall decrease in capital expenditures of $856,435 from 2016 Actual results to 2017 Bridge Year results summarized in Table 2-19 below.

Table 2-19: 2016 Actual versus 2017 Bridge Year Capital Expenditure Variances

Category	2016 Actual	2017 Bridge	Variance 2016 to 2017
System Access	1,211,917.00	1,271,457.00	**59,540.00**
System Renewal	4,243,808.00	3,372,227.00	**(871,581.00)**
Systerm Service	-	38,236.00	**38,236.00**
General Plant	82,630.00	-	**(82,630.00)**
Total Expenditure	**5,538,355.00**	**4,681,920.00**	**(856,435.00)**

System Access

In 2017, PUC Distribution experienced no material change in System capital expenditures.

System Renewal

- preliminary work on sub 16 rebuild
- Reduced restricted wire replacement
- Reduced voltage conversion
- Reduced deteriorated pole replacement

System Service

In 2016, PUC Distribution experienced no material change in System Service capital expenditures.

General Plant

In 2017, PUC Distribution experienced no material change in General Plant capital expenditures.

2017 Bridge Year versus 2018 Test Year Capital Expenditure Variances

PUC Distribution experienced an overall increase in capital expenditures of $676,435 from 2017 Bridge Year results to 2018 Test Year results summarized in Table 2-20 below.

Table 2-20: 2017 Bridge Year versus 2018 Test Year Capital Expenditure Variances

Category	2017 Bridge	2018 Test	Variance 2017 to 2018
System Access	1,271,457.00	1,511,028.00	**239,571.00**
System Renewal	3,372,227.00	3,761,033.00	**388,806.00**
Systerm Service	38,236.00	-	**(38,236.00)**
General Plant	-	86,294.00	**86,294.00**
Total Expenditure	**4,681,920.00**	**5,358,355.00**	**676,435.00**

System Access

- Increased new subdivisions & services
- Increased City projects
- Increased joint use projects
- Reduced energy storage project & related contributed capital

System Renewal

- Increased replacement of restricted wire program
- Increased preliminary work sub 16 rebuild

System Service

In 2018, PUC Distribution experienced no material change in System Service capital expenditures.

General Plant

In 2018, PUC Distribution experienced no material change in General Plant capital expenditures.

2019-2022 Forecast Capital Expenditure Variance Analysis

The planned capital expenditure for the five-year forecast period (2018 to 2022) indicates capital expenditures by PUC Distribution, net of the customer or third-party contributions will result in an average annual capital expenditure of approximately $6,856,747. The capital expenditures during the historic five years, after removing the extra ordinary expenditures related to construction of the integrated building and upgrade of the revenue meters with smart meters in 2012 and 2013, amount to an average annual capital expenditure of $ $6,680,739. The proposed average annual expenditure during the forecast period, thus, represents an increase of 2.6% from the average annual capital expenditure during the historic five years.

Table 2-20: Future Capital Expenditure Average Variances

Category	Foreast Period			
	2019	2020	2021	2022
System Access	1,615,276.00	2,086,480.00	1,603,804.00	1,560,434.00
System Renewal	6,905,898.00	3,296,444.00	4,532,889.00	7,092,642.00
System Service	-	-	-	-
General Plant	54,629.00	61,932.00	59,853.00	55,100.00
Total Expenditure	**8,575,803.00**	**5,446,876.00**	**6,198,567.00**	**8,710,198.00**

System Access

These investments include capital investments to implement customer service requests, joint-use requests from third party communication companies, line relocates to facilitate municipal infrastructure developments, such as road reconstruction projects and investments into revenue metering.

- 2020 – increased City Projects, Subdivisions & Services, and meter replacements

System Renewal

The proposed expenditure includes both reactive expenditures for replacement of the assets that have failed in service, as well as proactive replacement of assets where the risk of an assets' failure in service is unacceptable.

- 2019 –sub 16 rebuild
- 2021 – commencement of substation rebuild, preliminary work on transmission station rebuild
- 2022 – substation rebuild

System Service

There are no material changes planned in System Service capital expenditures.

General Plant

There are no material changes planned in General Plant capital expenditures.

Capital Projects

The table below provides a summary of all capital projects for the years 2013 through to the 2017 Bridge Year and 2018 Test Year, which is consistent with Board Appendix 2-AA and is included in Appendix 4 of this Exhibit. All projects above PUC Distribution's materiality threshold of $110,400 have been listed individually. PUC Distribution's DSP provides capital project summaries with a full description and justification of all individual material projects listed in Table 2-21 below for the 2018 Test Year. These summaries are found in PUC Distribution's DSP included in Appendix 2.

Table 2-21: Capital Project Table

Projects	2013	2014	2015	2016	2017 Bridge Year	2018 Test Year
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
New Services & Subdivisions						
Land Rights (Formally known as Account 1906)		3,411		1,736	1,057	1,138
Buildings						
Transformer Station Equipment >50 kV	10,633		14,422		5,143	5,541
Distribution Station Equipment <50 kV		41		468	104	113
Poles, Towers & Fixtures	256,877	401,663	184,799	274,915	229,541	247,298
Overhead Conductors & Devices	64,863	200,363	70,055	101,891	89,737	96,679
Underground Conduit	114,781	177,913	39,290	37,655	75,874	81,744
Underground Conductors & Devices	107,784	171,551	209,801	94,176	119,734	128,997
Line Transformers	238,554	367,159	418,565	279,567	267,636	288,341
Services (Overhead & Underground)	810,182	527,136	357,901	347,857	419,376	451,820
Meters	799	76	10,431	1,376	2,603	2,805
Sub-Total	**1,604,473**	**1,849,313**	**1,305,264**	**1,139,641**	**1,210,805**	**1,304,476**
Joint Use						
Poles, Towers & Fixtures	1,132,205	1,010,215	74,737	35,201	86,257	123,906
Overhead Conductors & Devices	114,063	66,940		28,982	8,042	11,552
Line Transformers	19,507	10,386	-4,856	8,696	1,292	1,856
Sub-Total	**1,265,775**	**1,087,540**	**69,881**	**72,879**	**95,590**	**137,313**
Meters						
Transformer Station Equipment >50 kV				529	220	146
Line Transformers				11,410	4,740	3,157
Services (Overhead & Underground)		561			233	155
Meters	229,274	139,712	42,513	82,277	205,105	136,601
Sub-Total	**229,274**	**140,273**	**42,513**	**94,217**	**210,298**	**140,060**
City Projects						
Poles, Towers & Fixtures		41,491	63,781	15,328	19,709	22,649
Overhead Conductors & Devices		8,524	24,949	11,466	7,344	8,440
Underground Conduit	12,345	78,700	120,026	86,962	48,705	55,971
Underground Conductors & Devices	213,579	348,298	379,454	41,381	160,597	184,556
Line Transformers		10,421	-1,654	-3,118	923	1,061
Services (Overhead & Underground)		10,198		180	1,696	1,949
Sub-Total	**225,924**	**497,632**	**586,556**	**152,198**	**238,975**	**274,627**

Distribution Overhead Renewal						
Land Rights (Formally known as Account 1906)		3,387			450	483
Distribution Station Equipment <50 kV		224		-96,685	-12,806	-13,752
Poles, Towers & Fixtures	166,342	631,378	644,093	355,614	238,631	256,256
Overhead Conductors & Devices	84,447	187,156	310,734	210,691	105,284	113,061
Underground Conduit	48,061	515		850	6,562	7,047
Underground Conductors & Devices		18,303	32,261	15,357	8,752	9,398
Line Transformers	30,758	122,900	40,144	128,906	42,844	46,008
Services (Overhead & Underground)				1,465	195	209
Meters	13,967				1,854	1,991
System Supervisor Equipment	1,154				153	165
Sub-Total	**344,730**	**963,864**	**1,027,231**	**616,199**	**391,918**	**420,865**
Distribution Underground Renewal						
Land Rights (Formally known as Account 1906)				4,740	940	
Poles, Towers & Fixtures	106	6,556	2,026	21,084	5,905	
Overhead Conductors & Devices	923		2,060	226	636	
Underground Conduit	50,542	17,968	128,515	86,025	56,141	
Underground Conductors & Devices	14,008	43,641.17	145,481.57	149,431.11	69,928	
Line Transformers		9,389.49	117,080.24	114,162.51	47,728	
Services (Overhead & Underground)	1,726				342	
Sub-Total	**67,304**	**77,555**	**395,164**	**375,669**	**181,621**	**0**
Forced Overhead Renewal						
Poles, Towers & Fixtures	174,753	145,135	107,906	155,818	177,116	190,818
Overhead Conductors & Devices	70,826	28,380	30,341	42,914	52,339	56,388
Underground Conduit			46	2,390	740	797
Underground Conductors & Devices			1,075	3,834	1,490	1,605
Line Transformers	40,398	8,804	40,494	72,397	49,192	52,998
Services (Overhead & Underground)	1,572	3,662			1,588	1,711
Meters	12,886	1,300			4,305	4,638
Sub-Total	**300,434**	**187,280**	**179,862**	**277,353**	**286,770**	**308,955**
Forced Underground Renewal						
Overhead Conductors & Devices				2,011	1,299	1,575
Underground Conductors & Devices				23,637	15,271	18,509
Line Transformers			132,840	236,062	238,336	288,871
Sub-Total	**0**	**0**	**132,840**	**261,710**	**254,906**	**308,955**
Restricted Wire Replacement						
Poles, Towers & Fixtures	166,908	23,679	130,895	372,010	274,814	418,175
Overhead Conductors & Devices	195,224	59,650	90,998	371,776	284,386	432,741
Line Transformers	15,436	12,128	36,009	133,426	78,066	118,790
Sub-Total	**377,568**	**95,458**	**257,902**	**877,211**	**637,266**	**969,706**
Transformers						
Line Transformers	88,125			59,775		56,024
Sub-Total	**88,125**	**0**	**0**	**59,775**	**0**	**56,024**

Substation 16						
Distribution Station Equipment <50 kV	19,871			35,585	73,445	121,065
Overhead Conductors & Devices	14,420				19,098	31,481
Line Transformers	122,592				162,362	267,633
Sub-Total	**156,883**	**0**	**0**	**35,585**	**254,906**	**420,179**
Station Upgrades - Dx						
Transformer Station Equipment >50 kV	49,279				12,288	7,759
Distribution Station Equipment <50 kV	855,072	358,362	433,146	315,900	489,365	308,987
Poles, Towers & Fixtures	348	563		850	439	277
Overhead Conductors & Devices	3,135			50,557	13,389	8,454
Underground Conduit		7,042			1,756	1,109
Services (Overhead & Underground)				51	13	8
System Supervisor Equipment		6,466		9,708	4,033	2,547
Sub-Total	**907,833**	**372,433**	**433,146**	**377,066**	**521,283**	**329,140**
Station Upgrades - Tx						
Transformer Station Equipment >50 kV	387,967	459,406	73,236	71,955		105,163
Distribution Station Equipment <50 kV	11,738	30,374		21,672		6,758
Poles, Towers & Fixtures	995					105
Overhead Conductors & Devices				202		21
Sub-Total	**400,700**	**489,779**	**73,236**	**93,829**	**0**	**112,048**
Voltage Conversion						
Distribution Station Equipment <50 kV	935		257,569		86,788	81,568
Poles, Towers & Fixtures	20,689		646,133	371,099	348,464	327,507
Overhead Conductors & Devices	30,175	45,055	336,557	457,601	291,882	274,327
Underground Conduit	526		51,597	163,259	72,311	67,962
Underground Conductors & Devices	5,787		17,822	5,606	9,809	9,219
Line Transformers	19,694	681	299,308	149,900	157,654	148,173
Services (Overhead & Underground)	5,170				1,736	1,631
Sub-Total	**82,976**	**45,737**	**1,608,986**	**1,147,466**	**968,644**	**910,387**
Switch Replacement						
Distribution Station Equipment <50 kV						
Poles, Towers & Fixtures		13,236				
Overhead Conductors & Devices	66,736	105,123.67	99,881.12			
Underground Conductors & Devices		18.71				
Line Transformers	46,482	4,578.38				
Services (Overhead & Underground)	14,590					
Sub-Total	**127,808**	**122,957**	**99,881**	**0**	**0**	**0**
Insulator Replacement						
Poles, Towers & Fixtures	291,484	4,489				
Overhead Conductors & Devices	10,491	242,586.42	185,049.10			
Sub-Total	**301,975**	**247,076**	**185,049**	**0**	**0**	**0**
New Building						
Buildings	1,861,207	244,854	66,532	82,630		
Poles, Towers & Fixtures	11					
Sub-Total	**1,861,219**	**244,854**	**66,532**	**82,630**	**0**	**0**

POD Generation						
Poles, Towers & Fixtures		2,726				
Sub-Total	**0**	**2,726**	**0**	**0**	**0**	**0**
34.5 kV Expansion						
Distribution Station Equipment <50 kV		86				
Underground Conductors & Devices		902.05				
Sub-Total	**0**	**988**	**0**	**0**	**0**	**0**
Substation 19						
Distribution Station Equipment <50 kV		163,164				
Sub-Total	**0**	**163,164**	**0**	**0**	**0**	**0**
Energy Storage Project						
Transformer Station Equipment >50 kV		158,518	-12,822	203,252.56	425,000	
Sub-Total	**0**	**158,518**	**-12,822**	**203,253**	**425,000**	**0**
PMH Replacement Program						
Distribution Station Equipment <50 kV		16,238				
Poles, Towers & Fixtures		836.63				
Overhead Conductors & Devices	11,064	10,455.85				
Underground Conductors & Devices	1,976					
Line Transformers		99,485.92	49,302.52	87,999		
Sub-Total	**13,040**	**127,016**	**49,303**	**87,999**	**0**	**0**
Substation 10						
Distribution Station Equipment <50 kV	2,942,315	674,216	174,344			
Poles, Towers & Fixtures	109,521					
Overhead Conductors & Devices	97,288	5,815.08	236.58			
Underground Conductors & Devices	57,863	6.34				
Line Transformers	35,219					
System Supervisor Equipment	32,153	21,741.08	4,349.42			
Sub-Total	**3,274,360**	**701,779**	**178,930**	**0**	**0**	**0**
SCADA						
Transformer Station Equipment >50 kV			25,347			4,170
Distribution Station Equipment <50 kV	128,475	970				21,297
System Supervisor Equipment	2,498	128,386.27	201.65	33,359		27,055
Sub-Total	**130,973**	**129,357**	**25,548**	**33,359**	**0**	**52,522**
Miscellaneous	36,153	1,483	5,693	588	0	63,099
Total	**11,797,527**	**7,706,781**	**6,710,694**	**5,988,627**	**5,677,982**	**5,808,354**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets *(input as negative)*						
Total	**11,797,527**	**7,706,781**	**6,710,694**	**5,988,627**	**5,677,982**	**5,808,354**

Non-Distribution Activities

PUC Distribution has excluded non-distribution activities in its capital expenditures, as such, no reconciliation is required.

Transmitter Capital Contributions

PUC Distribution has not made any transmitter capital contributions.

Conservation Initiatives

PUC Distribution has not experienced any material growth in its customer base or service territory, thus, has not had the need to consider incremental conservation initiatives to defer or otherwise avoid future infrastructure projects. This will remain true over the life of this Application.

PUC Distribution is not applying for funding through distribution rates to pursue activities such as energy efficiency programs, demand response programs, energy storage programs, etc.

Smart Meter Deployment

To make the distribution grid friendlier to distribute generation and to provide customers greater access and control on their energy usage, PUC Distribution is implementing affordable initiatives for smart grid development in a phased manner, to improve the stability and reliability of renewable generation connections and to meet customers' future needs. All of the customers have been equipped with smart meters. As the assets in existing distribution stations reach the end of their service life, during rebuilding of the distribution stations, modern automated switching and SCADA controlled devices are incorporated in the design.

PUC Distribution has made use of new data not available in the legacy meters. For example, the voltage readings from the smart metering system are reported back into the Geographic Information System ("GIS"). This information is used for maintenance planning to identify poor voltage areas. The locations shown to be receiving a voltage outside of PUC Distribution's standard can be proactively fixed before any damage is done to customer or utility equipment. The voltage reads are also used by the system planning department to help plan capital projects. The interval data can be aggregated to show what the load would be if specific customers were fed from the same transformer. This data assists engineers in planning transformer sizing.

PUC Distribution has also procured a population of remote disconnect meters during the smart meter project. These meters are being used to eliminate a field visit during the disconnect/reconnect process. The power to a meter can be turned on remotely from the system control office.

Another efficiency achieved, is the ability of the smart meter system to allow system control operators to check a customer's power and voltage readings on demand. This has resolved some customer inquiries immediately instead of requiring a field visit to verify power conditions. The smart metering system can also perform on demand reads. This has been used in both the billing department and in customer service to aid vacancy requests and billing inquiries while eliminating the need to send a truck.

2.2.2.3 Capitalization Policy

Capitalization Policy - IFRS

PUC Distribution follows Generally Accepted Accounting Principles, in particular the CICA Handbook *IAS 16 Property, Plant and Equipment* and the *OEB Accounting Procedure Handbook.*

A capital expenditure is defined as any significant expenditure incurred to acquire or improve land, buildings, plant, engineered structures, machinery and equipment used in providing services to customers. Improvement or "betterment" includes increasing capacity, reliability, efficiency or economy of operation or extending the useful life of a previous capital expenditure. It includes electric plant, vehicles, office furniture, computer equipment and other equipment. A capital expenditure normally provides a benefit lasting beyond one year and results in the acquisition of or extends the life of a fixed asset.

Components of PP&E are determined and depreciation is calculated separately for each significant component or part. Component accounting is required if the useful life and/or depreciation method for the component is different from the remainder of the asset.

Depreciation is based on the asset costs (or revalued cost) less its residual value over the estimated useful life. Estimates of residual values reflect prices at the reporting date given the condition the asset is expected to be in at the end of the useful life. Inflationary effects are not taken into account when determining the residual value. Estimates of useful life and residual value, and the method of depreciation, are reviewed at least each annual reporting date or where expectations differ from previous estimates.

The depreciation method selected is one that most closely reflects the pattern in which the asset's future economic benefits are expected to be consumed by the entity over its estimated useful life.

Directly attributed costs should be included in measuring the initial cost of an asset recognized in property, plant and equipment. General overhead and administrative costs are specifically excluded from the cost of the asset.

Expenditures for repairs and/or maintenance designed to maintain an asset in its original state is not a capital expenditure but should be charged to an operating account. Table 2-22 below provides the definition and accounting treatment for the various expenditures.

Table 2-22 Accounting Treatment and Definition of Capital Expenditure

	Definition	Accounting Treatment
Capital Expenditure	An expenditure to acquire or add to a capital asset – an expenditure yielding enduring benefits	Capitalize if above the materiality limit
Improvement	An expenditure made for the purpose of enhancing a fixed asset and which is an addition to the cost of the asset	Capitalize if above the materiality limit
Maintenance	The cost of keeping a property in efficient working condition	Current operations expense
Repair	The cost of replacement of parts or other restoration of plant and machinery, designed to	Current operations expense

	restore normal working efficiency	

The following Table 2-23 lists the materiality limits for the listed category of assets. Items with a cost less than the materiality levels as listed below should be charged to operations whether they are of a capital nature or of a repairs/maintenance nature.

Table 2-23 Materiality limits for Asset Categories

Account #	**Description**	**Limit**
	Electric Distribution	
1705, 1805, 1905	Land	All
1706, 1806, 1906	Land Right	$500
1708, 1808, 1908	Buildings	$500
1715, 1815	Transformer Station Equipment	$500
1820, 1825	Distribution Station Equipment	$500
1720, 1725, 1830	Poles, Towers and Fixtures	$500
1730, 1835	Lines & Feeders – O/H	$500
1735, 1840	Conduit – U/G	$500
1740, 1845	Lines & Feeders – U/G	$500
1850	Distribution Transformers	$500
1855	Services	All
1860	Meters	All
1915	General Office Equipment	$500
1920, 1925	Computer Equipment	$500

1935	Stores Warehouse Equipment	$500
1930	Rolling Stock	$500
1940, 1945	Miscellaneous Equipment	$500
1955	Communication Equipment	$500
1980	System Supervisory Equipment	$500

2.2.2.4 Capitalization of Overhead

As noted above, PP&E is recorded at cost – including purchase price, costs to bring the asset to the location and condition necessary to operate, etc. One of the costs explicitly prohibited from being included in the cost of an asset under IFRS is “administrative and other general overhead costs”.

As outlined in Appendix 5 – App 2-D Overhead Expense, PUC Distribution currently includes the following in PP&E costs: direct labour, direct material from inventory or from a third party vendor, and vehicle costs used to bring the asset to the location and condition necessary to operate. Direct labour costs are based on an hourly rate and the number of hours that an employee works on a specific project. Also, included in direct labour costs are health benefits, CPP, and EI. These costs are allocated to capital and period expenses based on the percentage of total labour dollars directly charged to each. Material from inventory or from a third party is charged directly to the asset that the material is used for. Vehicles are charged to a specific job based on an hourly rate and the number of hours the vehicle is used on the job. The hourly vehicle rate is estimated annually and “trued-up” at year end to account for actual costs.

PUC Distribution will continue to capitalize costs that are directly attributable to bringing the asset to the location and condition necessary to operate. These costs include the direct labour with an allocation for health benefits, CPP and EI, material costs, and vehicle costs. PUC Distribution will not capitalize any administrative or general overheard costs.

Compliance of Sampling of Smart Meters

PUC Distribution is in the early stages of its Smart Meter Compliance Plan implementation.

The original meters are approaching 10 years of age and are scheduled for meter re-verification, as to Measurement Canada requirements. It is anticipated that purchase of replacement meters will begin in late 2016 and continue thereafter.

Further details of the Smart Meter Compliance plan can be found in Appendix F to the DSP, which is attached to this Exhibit as Appendix 2.

2.2.2.5 Costs of Eligible Investments for the Connection of Qualifying Generation Facilities

Overview

Section 2.2.2.5 of the Filing Requirements contemplates that a distributor will file for provincial rate protection associated with any costs incurred to make eligible investments, as described in Section 79.1 of the Ontario Energy Board Act and Regulation 330/09 ("O. Reg. 330/09") made under the Act.

Costs incurred by a distributor, in accordance with cost responsibility rules in the Board's Distribution

System Code for the purpose of connecting or enabling the connection of Renewable Energy Generation ("REG") facilities to its distribution system, are considered to be eligible investments for the purpose of Provincial rate recovery under Section 79.1 of the Act.

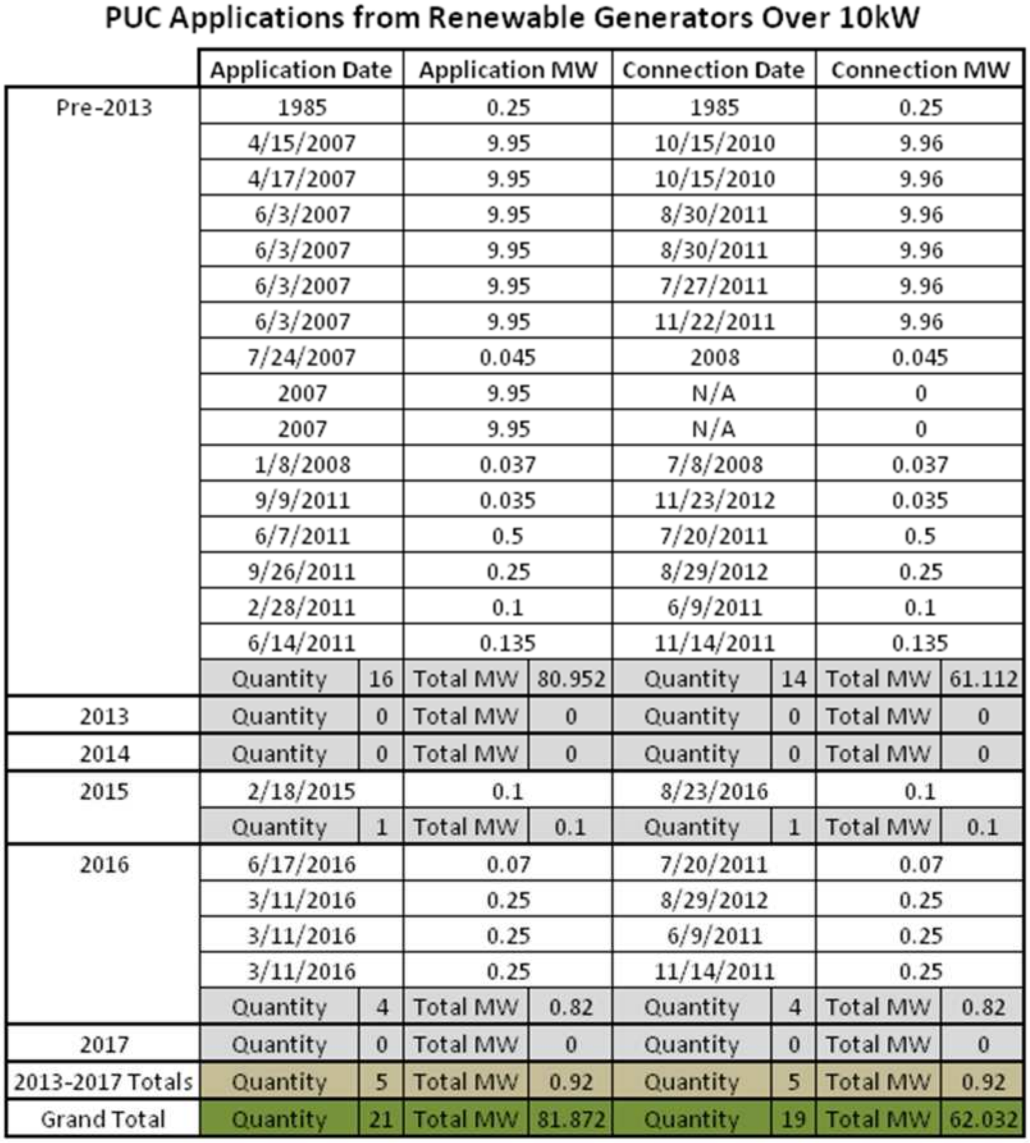
History

PUC Distribution currently has approximately 63MW of REG connected to its distribution system, which on occasion results in net export conditions during summer months when the distribution network is near its minimum load. PUC Distribution also hosts an IESO controlled 7MW/7MWh battery energy storage facility.

Applications for REG Greater than 10kW

The connection history for all REG installations connected to the PUC distribution system over 10kW is illustrated in Table 2-24 below. Of all the applications made, those that were not connected had applications terminated by the applicant and in no cases was unavailable capacity the deciding factor.

Table 2-24 - Applications for REG Over 10kW



PUC Applications from Renewable Generators Over 10kW

	Application Date		Application MW		Connection Date		Connection MW	
Pre-2013	1985		0.25		1985		0.25	
	4/15/2007		9.95		10/15/2010		9.96	
	4/17/2007		9.95		10/15/2010		9.96	
	6/3/2007		9.95		8/30/2011		9.96	
	6/3/2007		9.95		8/30/2011		9.96	
	6/3/2007		9.95		7/27/2011		9.96	
	6/3/2007		9.95		11/22/2011		9.96	
	7/24/2007		0.045		2008		0.045	
	2007		9.95		N/A		0	
	2007		9.95		N/A		0	
	1/8/2008		0.037		7/8/2008		0.037	
	9/9/2011		0.035		11/23/2012		0.035	
	6/7/2011		0.5		7/20/2011		0.5	
	9/26/2011		0.25		8/29/2012		0.25	
	2/28/2011		0.1		6/9/2011		0.1	
	6/14/2011		0.135		11/14/2011		0.135	
	Quantity	16	Total MW	80.952	Quantity	14	Total MW	61.112
2013	Quantity	0	Total MW	0	Quantity	0	Total MW	0
2014	Quantity	0	Total MW	0	Quantity	0	Total MW	0
2015	2/18/2015		0.1		8/23/2016		0.1	
	Quantity	1	Total MW	0.1	Quantity	1	Total MW	0.1
2016	6/17/2016		0.07		7/20/2011		0.07	
	3/11/2016		0.25		8/29/2012		0.25	
	3/11/2016		0.25		6/9/2011		0.25	
	3/11/2016		0.25		11/14/2011		0.25	
	Quantity	4	Total MW	0.82	Quantity	4	Total MW	0.82
2017	Quantity	0	Total MW	0	Quantity	0	Total MW	0
2013-2017 Totals	Quantity	5	Total MW	0.92	Quantity	5	Total MW	0.92
Grand Total	Quantity	21	Total MW	81.872	Quantity	19	Total MW	62.032

Applications for REG 10kW or less

Currently there are no applications in the queue from REG connections <10kW, under the Micro-FIT program and all requests for Micro-FIT generation received to date have been successfully connected to the system. There appears to be a growing interest in net metering and some discussions about that in conjunction with energy storage behind the meter as the gap closes between Micro-FIT contract pricing and the Residential class load energy costs.

System Capacity to Support REG

Primarily based on thermal ratings of conductors and transformers, PUC Distribution has developed and submitted to the IESO, the following table of available capacity. The IESO uses this for planning and as an input to preparing a Transmission Availability Table (TAT) which is posted online to assist prospective REG applicants in selecting a site for their project. Table 2-25 summarizes available capacity at the 34.5kV feeder and station bus levels. It can be seen that at present there is still capacity available for the future connection of approximately 27MW more generation between circuits out of TS1 and TS2 combined.

Table 2-25 - PUC Available Capacity

Station	Bus Name	Capacity (MW)	Allocated Capacity (MW)	Available Capacity (MW)	Supply Circuit 1	Supply Circuit 2
TS1 **(St. Mary's)**	**Total**	**45**	**41.310**	**3.690**	**GL1SM**	**GL2SM**
	West	30	21.009	3.690		
	East	30	20.300	3.690		
TS2 **(Tarentorus)**	**Total**	**45**	**21.663**	**23.337**	**GL1TA**	**GL2TA**
	West	30	21.015	8.985		
	East	30	0.647	23.337		

34.5 kV Feeder Name	Bus Connection	Capacity (MW)	Allocated Capacity	Available Capacity (MW)	Notes:
SM-5	West	30	10.214	3.690	TS Limiting (45-D5) MW
SM-7	West	30	9.960	3.690	TS Limiting (45-D5) MW
Sub 19 West	West	N/A	0.835	N/A	no feeder, direct bus connection
SM-9	East	30	10.034	3.690	TS Limiting (45-D5) MW
SM-11	East	30	10.017	3.690	TS Limiting (45-D5) MW
Sub 19 East	East	N/A	0.250	N/A	no feeder, direct bus connection
TS1			**41.310**		
TA-6	West	30	0.139	23.337	TS Limiting (45-D8) MW
TA-7	West	30	20.876	8.985	West Bus Limiting (30-D9) MW
TA-9	East	30	0.028	23.337	TS Limiting (45-D8) MW
TA-10	East	30	0.188	23.337	TS Limiting (45-D8) MW
TA-11	East	30	0.431	23.337	TS Limiting (45-D8) MW
TS2			**21.663**		

Proposed Plan and Investments to Support REG

The PUC Distribution grid is presently very well positioned to support all forecast REG connections over the next five years and no associated infrastructure investment is required during that period.

Please see Appendices 2-FA through 2-FC attached as Appendices 6 to 8 which indicate there are on eligible investments for recovery.

2.2.2.6 New Policy Options for the Funding of Capital

On September 18, 2014, the Board released the *"Report of the Board New Policy Options for the Funding* of Capital Investments: The Advanced Capital Module" and in it the Board has established the following mechanism to assist distributors in aligning capital expenditure timing and prioritization with rate predictability and smoothing:

The review and approval of business cases for incremental capital requests that are subject to the criteria of materiality, need and prudence are advanced to coincide with the distributor's cost of service application. To distinguish this from the Incremental Capital Module ("ICM"), this new mechanism will be named the Advanced Capital Module ("ACM")

Advancing the reviews of eligible discrete capital projects, included as part of a distributor's

Distribution System Plan ("DSP") and scheduled to do into service during the IR term, is expected to facilitate enhanced pacing and smoothing of rate impacts, as the distributor, the Board and other stakeholders will be examining the capital projects over the five-year horizon of the DSP.

At this time, PUC Distribution has planned for distribution station replacements within the five-year cost of service rate horizon that it believes would require rate increases. PUC Distribution plans to file Incremental Capital Modules at the appropriate time to address the funding of the distribution station rebuilds.

2.2.2.7 Additions of ICM Assets To Rate Base

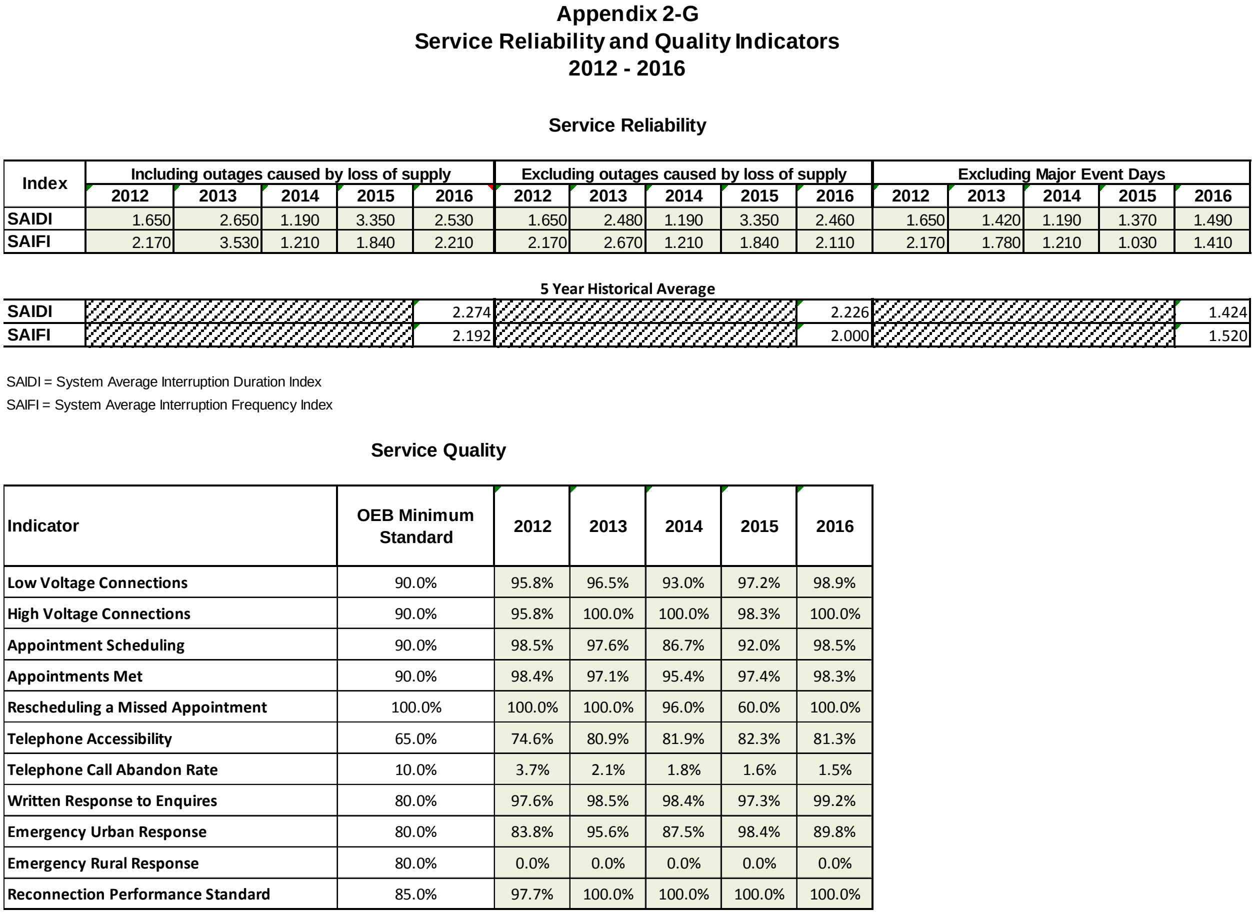
PUC Distribution has not applied for, nor received approval of any ICM assets and therefore has no such asset added to its rate base. Accordingly, PUC Distribution has not completed the Board's Capital Model applicable to ACM and ICM – Version 3.01.

Service Quality and Reliability Performance

PUC Distribution follows the Board's Reporting and Record Keeping Requirements Guideline to report its Service Quality Indicators annually. In accordance with the Filing Requirements, Table 2-26 is provided below which is consistent with the Board Appendix 2-G, Service Quality Indicators and is included as Appendix 9 to this Exhibit. The table provides the performance measures for the last five historical years 2012 through 2016. Also included below in Table 2-27 is a summary of PUC Distribution's Major Events between 2012 and 2016 as reported in the Reporting and Record Keeping Requirements (RRR).

PUC Distribution has consistently performed within the Board's range of acceptable performance over the five years and no corrective action is required.

Table 2-26: Service Reliability



Appendix 2-G
Service Reliability and Quality Indicators
2012 - 2016

Service Reliability

Index	Including outages caused by loss of supply					Excluding outages caused by loss of supply					Excluding Major Event Days				
	2012	2013	2014	2015	2016	2012	2013	2014	2015	2016	2012	2013	2014	2015	2016
SAIDI	1.650	2.650	1.190	3.350	2.530	1.650	2.480	1.190	3.350	2.460	1.650	1.420	1.190	1.370	1.490
SAIFI	2.170	3.530	1.210	1.840	2.210	2.170	2.670	1.210	1.840	2.110	2.170	1.780	1.210	1.030	1.410

5 Year Historical Average

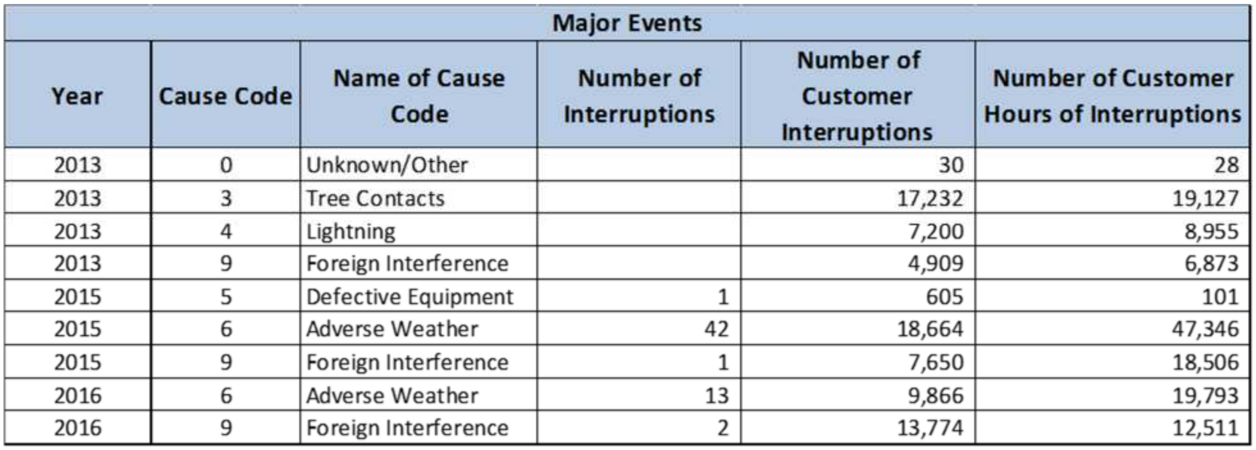
SAIDI	2.274	2.226	1.424
SAIFI	2.192	2.000	1.520

SAIDI = System Average Interruption Duration Index
SAIFI = System Average Interruption Frequency Index

Service Quality

Indicator	OEB Minimum Standard	2012	2013	2014	2015	2016
Low Voltage Connections	90.0%	95.8%	96.5%	93.0%	97.2%	98.9%
High Voltage Connections	90.0%	95.8%	100.0%	100.0%	98.3%	100.0%
Appointment Scheduling	90.0%	98.5%	97.6%	86.7%	92.0%	98.5%
Appointments Met	90.0%	98.4%	97.1%	95.4%	97.4%	98.3%
Rescheduling a Missed Appointment	100.0%	100.0%	100.0%	96.0%	60.0%	100.0%
Telephone Accessibility	65.0%	74.6%	80.9%	81.9%	82.3%	81.3%
Telephone Call Abandon Rate	10.0%	3.7%	2.1%	1.8%	1.6%	1.5%
Written Response to Enquires	80.0%	97.6%	98.5%	98.4%	97.3%	99.2%
Emergency Urban Response	80.0%	83.8%	95.6%	87.5%	98.4%	89.8%
Emergency Rural Response	80.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Reconnection Performance Standard	85.0%	97.7%	100.0%	100.0%	100.0%	100.0%

Table 2-27: Summary of Major Events 2012-2016



Major Events					
Year	Cause Code	Name of Cause Code	Number of Interruptions	Number of Customer Interruptions	Number of Customer Hours of Interruptions
2013	0	Unknown/Other		30	28
2013	3	Tree Contacts		17,232	19,127
2013	4	Lightning		7,200	8,955
2013	9	Foreign Interference		4,909	6,873
2015	5	Defective Equipment	1	605	101
2015	6	Adverse Weather	42	18,664	47,346
2015	9	Foreign Interference	1	7,650	18,506
2016	6	Adverse Weather	13	9,866	19,793
2016	9	Foreign Interference	2	13,774	12,511

Further performance discussions regarding Service Quality Indicators can be found in Exhibit 1.

APPENDIX 1

Fixed Asset Continuity Schedules, Board Appendix 2-BA

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard CGAAP
Year **2012**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
N/A	1706	Land Rights	$ 602,307.45			$ 602,307				$ -	$ 602,307
47	1725	Poles and Fixtures	$ 2,018,423.69		$ (143,123.57)	$ 1,875,300	-$ 276,243	-$ 71,122	$ 143,124	-$ 204,242	$ 1,671,058
47	1730	Overhead Conductors & Devices	$ 97,606.00		$ (7,532.00)	$ 90,074	-$ 19,045	-$ 7,568	$ 7,532	-$ 19,081	$ 70,993
47	1735	Underground Conduit	$ 1,017,684.79		$ (357.22)	$ 1,017,328	-$ 71,149	-$ 38,779	$ 357	-$ 109,571	$ 907,756
47	1740	Underground Conductors & Devices	$ 244,903.00		$ (84.00)	$ 244,819	-$ 13,869	-$ 7,999	$ 84	-$ 21,784	$ 223,035
12	1611	Computer Software (Formally known as Account 1925)				$ -				$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)				$ -				$ -	$ -
N/A	1805	Land	$ 89,159.57			$ 89,160				$ -	$ 89,160
CEC	1806	Land Rights	$ 234,274.82	$ 8,432.60	$ (89,134.00)	$ 153,573				$ -	$ 153,573
47	1808	Buildings	$ 1,242,325.61	$ 22,916,497.31	$ (20,404.00)	$ 24,138,419	-$ 674,422	-$ 38,839		-$ 713,261	$ 23,425,158
13	1810	Leasehold Improvements				$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 8,312,485.32	$ 442,023.05	$ (146,448.54)	$ 8,608,060	-$ 3,295,805	-$ 204,328	$ 146,449	-$ 3,353,684	$ 5,254,376
47	1820	Distribution Station Equipment <50 kV	$ 9,490,317.22	$ 1,158,544.88		$ 10,648,862	-$ 6,284,040	-$ 144,411		-$ 6,428,451	$ 4,220,411
47	1825	Storage Battery Equipment	$ 19,241.00			$ 19,241	-$ 4,239	-$ 640		-$ 4,879	$ 14,362
47	1830	Poles, Towers & Fixtures	$ 11,395,085.91	$ 1,453,463.52		$ 12,848,549	-$ 4,206,992	-$ 231,936		-$ 4,438,928	$ 8,409,622
47	1835	Overhead Conductors & Devices	$ 11,820,056.52	$ 1,368,569.65		$ 13,188,626	-$ 5,281,196	-$ 156,301		-$ 5,437,497	$ 7,751,129
47	1840	Underground Conduit	$ 10,185,019.73	$ 332,904.82	$ 108,931.00	$ 10,626,856	-$ 8,153,826	-$ 74,365		-$ 8,228,190	$ 2,398,665
47	1845	Underground Conductors & Devices	$ 19,164,687.01	$ 597,638.47		$ 19,762,325	-$ 7,896,803	-$ 401,917		-$ 8,298,720	$ 11,463,606
47	1850	Line Transformers	$ 15,659,948.03	$ 1,124,624.28		$ 16,784,572	-$ 7,614,082	-$ 300,328		-$ 7,914,410	$ 8,870,162
47	1855	Services (Overhead & Underground)	$ 3,623,556.42	$ 449,031.61		$ 4,072,588	-$ 263,427	-$ 88,270		-$ 351,697	$ 3,720,891
47	1860	Meters				$ -				$ -	$ -
47	1860	Meters (Smart Meters)	$ 4,478,778.99	$ 6,129,074.92	$ (241,081.70)	$ 10,366,772	-$ 2,933,376	-$ 1,588,345	$ 241,082	-$ 4,280,639	$ 6,086,133
N/A	1905	Land				$ -				$ -	$ -
47	1908	Buildings & Fixtures				$ -				$ -	$ -
13	1910	Leasehold Improvements				$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)				$ -				$ -	$ -
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 13,578.34	$ 6,760.00		$ 20,338	-$ 9,316	-$ 7,535		-$ 16,850	$ 3,488
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
12	1925	Compute rSoftware	$ 38,397.00	$ 521,482.63	$ (25,872.01)	$ 534,008	-$ 38,372	-$ 312,437	$ 25,872	-$ 324,937	$ 209,071
10	1930	Transportation Equipment				$ -				$ -	$ -
8	1935	Stores Equipment				$ -				$ -	$ -
8	1940	Tools, Shop & Garage Equipment				$ -				$ -	$ -
8	1945	Measurement & Testing Equipment				$ -				$ -	$ -
8	1950	Power Operated Equipment				$ -				$ -	$ -
8	1955	Communications Equipment				$ -				$ -	$ -
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	1960	Miscellaneous Equipment				$ -				$ -	$ -
47	1970	Load Management Controls Customer Premises	$ 27,814.00		$ (27,814.00)	$ -	-$ 12,542		$ 12,542	$ -	$ -
47	1975	Load Management Controls Utility Premises				$ -				$ -	$ -
47	1980	System Supervisor Equipment	$ 3,887,893.04	$ 305,142.88		$ 4,193,036	-$ 2,571,456	-$ 196,831		-$ 2,768,287	$ 1,424,748
47	1985	Miscellaneous Fixed Assets				$ -				$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants	$ (10,987,086.37)	$ (785,722.21)		-$ 11,772,809	$ 1,388,648	$ 282,137		$ 1,670,785	-$ 10,102,023
47	2440	Deferred Revenue[5]									
						$ -				$ -	$ -
		Sub-Total	**$ 92,676,457**	**$ 36,028,468**	**-$ 592,920**	**$ 128,112,005**	**-$ 48,231,552**	**-$ 3,589,813**	**$ 577,041**	**-$ 51,244,324**	**$ 76,867,682**
		Less Socialized Renewable Energy Generation Investments **(input as negative)**				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets ***(input as negative)***				$ -				$ -	$ -
		Total PP&E	**$ 92,676,457**	**$ 36,028,468**	**-$ 592,920**	**$ 128,112,005**	**-$ 48,231,552**	**-$ 3,589,813**	**$ 577,041**	**-$ 51,244,324**	**$ 76,867,682**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 3,589,813**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 3,589,813

Appendix 2-BA
Fixed Asset Continuity Schedule[1]

Accounting Standard CGAAP
Year **2013**

			Cost				Accumulated Depreciation				
CCA Class[2]	**OEB Account[3]**	**Description[3]**	**Opening Balance**	**Additions[4]**	**Disposals[6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals[6]**	**Closing Balance**	**Net Book Value**
N/A	1706	Land Rights	$ 602,307.00			$ 602,307				$ -	$ 602,307
47	1725	Poles and Fixtures	$ 1,875,300.00		$ (121,813.00)	$ 1,753,487	-$ 204,242	-$ 66,718	$ 121,813	-$ 149,147	$ 1,604,340
47	1730	Overhead Conductors & Devices	$ 90,074.00			$ 90,074	-$ 19,081	-$ 7,099		-$ 26,180	$ 63,894
47	1735	Underground Conduit	$ 1,017,328.00		$ (31,461.00)	$ 985,867	-$ 109,571	-$ 37,736	$ 31,461	-$ 115,846	$ 870,021
47	1740	Underground Conductors & Devices	$ 244,819.00			$ 244,819	-$ 21,784	-$ 7,783		-$ 29,567	$ 215,252
12	1611	Computer Software (Formally known as Account 1925)				$ -				$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)				$ -				$ -	$ -
N/A	1805	Land	$ 89,160.00			$ 89,160				$ -	$ 89,160
CEC	1806	Land Rights	$ 153,573.00	$ 555.00		$ 154,128				$ -	$ 154,128
47	1808	Buildings	$ 24,138,419.00	$ 1,861,467.00		$ 25,999,886	-$ 713,261	-$ 661,658		-$ 1,374,919	$ 24,624,967
13	1810	Leasehold Improvements				$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 8,608,060.00	$ 448,214.00		$ 9,056,274	-$ 3,353,684	-$ 210,868		-$ 3,564,552	$ 5,491,722
47	1820	Distribution Station Equipment <50 kV	$ 10,648,862.00	$ 3,832,429.00		$ 14,481,291	-$ 6,428,451	-$ 240,222		-$ 6,668,673	$ 7,812,618
47	1825	Storage Battery Equipment	$ 19,241.00			$ 19,241	-$ 4,879	-$ 640		-$ 5,519	$ 13,722
47	1830	Poles, Towers & Fixtures	$ 12,848,549.00	$ 2,320,239.00		$ 15,168,788	-$ 4,438,928	-$ 283,445		-$ 4,722,373	$ 10,446,415
47	1835	Overhead Conductors & Devices	$ 13,188,626.00	$ 763,655.00		$ 13,952,281	-$ 5,437,497	-$ 169,054		-$ 5,606,551	$ 8,345,730
47	1840	Underground Conduit	$ 10,626,856.00	$ 226,255.00		$ 10,853,111	-$ 8,228,190	-$ 78,890		-$ 8,307,080	$ 2,546,031
47	1845	Underground Conductors & Devices	$ 19,762,325.00	$ 400,996.00		$ 20,163,321	-$ 8,298,720	-$ 427,501		-$ 8,726,221	$ 11,437,100
47	1850	Line Transformers	$ 16,784,572.00	$ 675,571.00	$ (25,049.00)	$ 17,435,094	-$ 7,914,410	-$ 316,591		-$ 8,231,001	$ 9,204,093
47	1855	Services (Overhead & Underground)	$ 4,072,588.00	$ 833,240.00		$ 4,905,828	-$ 351,697	-$ 93,542		-$ 445,239	$ 4,460,589
47	1860	Meters	$ 10,366,772.00	$ 271,622.00	$ (4,298,049.00)	$ 6,340,345	-$ 4,280,639	-$ 428,593	$ 2,837,860	-$ 1,871,372	$ 4,468,973
47	1860	Meters (Smart Meters)				$ -				$ -	$ -
N/A	1905	Land				$ -				$ -	$ -
47	1908	Buildings & Fixtures				$ -				$ -	$ -
13	1910	Leasehold Improvements				$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)				$ -				$ -	$ -
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 20,338.00			$ 20,338	-$ 16,850	-$ 2,127		-$ 18,977	$ 1,361
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
12	1925	Compute rSoftware	$ 534,008.00	$ 1,500.00		$ 535,508	-$ 324,937	-$ 104,597		-$ 429,534	$ 105,974
10	1930	Transportation Equipment				$ -				$ -	$ -
8	1935	Stores Equipment				$ -				$ -	$ -
8	1940	Tools, Shop & Garage Equipment				$ -				$ -	$ -
8	1945	Measurement & Testing Equipment				$ -				$ -	$ -
8	1950	Power Operated Equipment				$ -				$ -	$ -
8	1955	Communications Equipment				$ -				$ -	$ -
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	1960	Miscellaneous Equipment				$ -				$ -	$ -
47	1970	Load Management Controls Customer Premises				$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises				$ -				$ -	$ -
47	1980	System Supervisor Equipment	$ 4,193,036.00	$ 161,782.00		$ 4,354,818	-$ 2,768,287	-$ 204,920		-$ 2,973,207	$ 1,381,611
47	1985	Miscellaneous Fixed Assets				$ -				$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants	$ (11,772,809.00)	$ (1,376,260.00)		-$ 13,149,069	$ 1,670,785	$ 316,544		$ 1,987,329	-$ 11,161,740
47	2440	Deferred Revenue[5]									
						$ -				$ -	$ -
		Sub-Total	**$ 128,112,004**	**$ 10,421,265**	**-$ 4,476,372**	**$ 134,056,897**	**-$ 51,244,323**	**-$ 3,025,440**	**$ 2,991,134**	**-$ 51,278,629**	**$ 82,778,268**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 128,112,004**	**$ 10,421,265**	**-$ 4,476,372**	**$ 134,056,897**	**-$ 51,244,323**	**-$ 3,025,440**	**$ 2,991,134**	**-$ 51,278,629**	**$ 82,778,268**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 3,025,440**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 3,025,440

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard	MIFRS
Year	**2014**

			Cost				**Accumulated Depreciation**				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
N/A	1706	Land Rights	$ 602,307			$ 602,307	$ -			$ -	$ 602,307
47	1725	Poles and Fixtures	$ 1,604,340			$ 1,604,340	$ -	$ (39,130.00)		-$ 39,130	$ 1,565,210
47	1730	Overhead Conductors & Devices	$ 63,894			$ 63,894	$ -	$ (1,997.00)		-$ 1,997	$ 61,897
47	1735	Underground Conduit	$ 870,021			$ 870,021	$ -	$ (24,858.00)		-$ 24,858	$ 845,163
47	1740	Underground Conductors & Devices	$ 215,252			$ 215,252	$ -	$ (9,784.00)		-$ 9,784	$ 205,468
12	1611	Computer Software (Formally known as Account 1925)	$ -			$ -	$ -			$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 89,160			$ 89,160	$ -			$ -	$ 89,160
CEC	1806	Land Rights	$ 154,128	$ 6,798.00		$ 160,926	$ -			$ -	$ 160,926
47	1808	Buildings	$ 24,624,967	$ 244,854.00		$ 24,869,821	$ -	$ (675,297.00)		-$ 675,297	$ 24,194,524
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 5,491,722	$ 617,923.00		$ 6,109,645	$ -	$ (236,546.00)		-$ 236,546	$ 5,873,099
47	1820	Distribution Station Equipment <50 kV	$ 7,812,618	$ 1,245,158.00		$ 9,057,776	$ -	$ (370,683.00)		-$ 370,683	$ 8,687,093
47	1825	Storage Battery Equipment	$ 13,722			$ 13,722	$ -	$ (653.00)		-$ 653	$ 13,069
47	1830	Poles, Towers & Fixtures	$ 10,446,415	$ 2,281,968.00		$ 12,728,383	$ -	$ (262,774.00)		-$ 262,774	$ 12,465,609
47	1835	Overhead Conductors & Devices	$ 8,345,730	$ 960,049.00		$ 9,305,779	$ -	$ (239,826.00)		-$ 239,826	$ 9,065,953
47	1840	Underground Conduit	$ 2,546,031	$ 282,137.00		$ 2,828,168	$ -	$ (214,991.00)		-$ 214,991	$ 2,613,177
47	1845	Underground Conductors & Devices	$ 11,437,100	$ 582,719.00		$ 12,019,819	$ -	$ (504,549.00)		-$ 504,549	$ 11,515,270
47	1850	Line Transformers	$ 9,204,093	$ 645,934.00		$ 9,850,027	$ -	$ (244,077.00)		-$ 244,077	$ 9,605,950
47	1855	Services (Overhead & Underground)	$ 4,460,589	$ 541,557.00		$ 5,002,146	$ -	$ (130,675.00)		-$ 130,675	$ 4,871,471
47	1860	Meters	$ 4,468,973	$ 141,089.00		$ 4,610,062	$ -	$ (410,973.00)		-$ 410,973	$ 4,199,089
47	1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 1,361			$ 1,361	$ -	$ (1,361.00)		-$ 1,361	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
12	1925	Compute rSoftware	$ 105,974			$ 105,974	$ -	-$ 105,974		-$ 105,974	$ -
10	1930	Transportation Equipment	$ -			$ -	$ -			$ -	$ -
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -			$ -	$ -			$ -	$ -
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 1,381,611	$ 156,593.00		$ 1,538,204	$ -	$ (234,183.00)		-$ 234,183	$ 1,304,021
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 11,161,740	$ (1,045,731.00)		-$ 12,207,471	$ -	$ 341,358		$ 341,358	-$ 11,866,113
47	2440	Deferred Revenue[5]	$ -				$ -				
						$ -				$ -	$ -
		Sub-Total	**$ 82,778,268**	**$ 6,661,048**	**$ -**	**$ 89,439,316**	**$ -**	**-$ 3,366,973**	**$ -**	**-$ 3,366,973**	**$ 86,072,343**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 82,778,268**	**$ 6,661,048**	**$ -**	**$ 89,439,316**	**$ -**	**-$ 3,366,973**	**$ -**	**-$ 3,366,973**	**$ 86,072,343**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 3,366,973**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 3,366,973

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year **2015**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
N/A	1706	Land Rights	$ 602,307			$ 602,307	$ -			$ -	$ 602,307
47	1725	Poles and Fixtures	$ 1,604,340			$ 1,604,340	-$ 39,130	$ (39,130.00)		-$ 78,260	$ 1,526,080
47	1730	Overhead Conductors & Devices	$ 63,894			$ 63,894	-$ 1,997	$ (1,997.00)		-$ 3,994	$ 59,900
47	1735	Underground Conduit	$ 870,021			$ 870,021	-$ 24,858	$ (24,858.00)		-$ 49,716	$ 820,305
47	1740	Underground Conductors & Devices	$ 215,252			$ 215,252	-$ 9,784	$ (9,784.00)		-$ 19,568	$ 195,684
12	1611	Computer Software (Formally known as Account 1925)	$ -			$ -	$ -			$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 89,160			$ 89,160	$ -			$ -	$ 89,160
CEC	1806	Land Rights	$ 160,926	$ 5,693.00		$ 166,619				$ -	$ 166,619
47	1808	Buildings	$ 24,869,821	$ 66,532.00		$ 24,936,353	-$ 675,297	$ (678,518.00)		-$ 1,353,815	$ 23,582,538
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 6,109,645	$ 100,183.00		$ 6,209,828	-$ 236,546	$ (245,522.00)		-$ 482,068	$ 5,727,760
47	1820	Distribution Station Equipment <50 kV	$ 9,057,776	$ 865,058.00		$ 9,922,834	-$ 370,683	$ (397,061.00)		-$ 767,744	$ 9,155,090
47	1825	Storage Battery Equipment	$ 13,722			$ 13,722	-$ 653	$ (653.00)		-$ 1,306	$ 12,416
47	1830	Poles, Towers & Fixtures	$ 12,728,383	$ 1,854,371.00		$ 14,582,754	-$ 262,774	$ (308,733.00)		-$ 571,507	$ 14,011,247
47	1835	Overhead Conductors & Devices	$ 9,305,779	$ 1,150,860.00		$ 10,456,639	-$ 239,826	$ (257,417.00)		-$ 497,243	$ 9,959,396
47	1840	Underground Conduit	$ 2,828,168	$ 339,474.00		$ 3,167,642	-$ 214,991	$ (221,207.00)		-$ 436,198	$ 2,731,444
47	1845	Underground Conductors & Devices	$ 12,019,819	$ 785,894.00		$ 12,805,713	-$ 504,549	$ (521,657.00)		-$ 1,026,206	$ 11,779,507
47	1850	Line Transformers	$ 9,850,027	$ 1,127,232.00		$ 10,977,259	-$ 244,077	$ (266,241.00)		-$ 510,318	$ 10,466,941
47	1855	Services (Overhead & Underground)	$ 5,002,146	$ 357,901.00		$ 5,360,047	-$ 130,675	$ (141,918.00)		-$ 272,593	$ 5,087,454
47	1860	Meters	$ 4,610,062	$ 52,944.00		$ 4,663,006	-$ 410,973	$ (417,441.00)		-$ 828,414	$ 3,834,592
47	1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 1,361		$ (1,361.00)	$ -	-$ 1,361		$ 1,361.00	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
12	1925	Compute rSoftware	$ 105,974		$ (105,974.00)	$ -	-$ 105,974		$ 105,974	$ -	$ -
10	1930	Transportation Equipment	$ -			$ -	$ -			$ -	$ -
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -			$ -	$ -			$ -	$ -
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 1,538,204	$ 4,551.00		$ 1,542,755	-$ 234,183	$ (238,212.00)		-$ 472,395	$ 1,070,360
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 12,207,471	$ (454,801.00)		-$ 12,662,272	$ 341,358	$ 360,115.00		$ 701,473	-$ 11,960,799
47	2440	Deferred Revenue[5]	$ -				$ -				
						$ -				$ -	$ -
		Sub-Total	**$ 89,439,316**	**$ 6,255,892**	**-$ 107,335**	**$ 95,587,873**	**-$ 3,366,973**	**-$ 3,410,234**	**$ 107,335**	**-$ 6,669,872**	**$ 88,918,001**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 89,439,316**	**$ 6,255,892**	**-$ 107,335**	**$ 95,587,873**	**-$ 3,366,973**	**-$ 3,410,234**	**$ 107,335**	**-$ 6,669,872**	**$ 88,918,001**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 3,410,234**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 3,410,234

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year **2016**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
N/A	1706	Land Rights	$ 602,307			$ 602,307	$ -			$ -	$ 602,307
47	1725	Poles and Fixtures	$ 1,604,340			$ 1,604,340	-$ 78,260	$ (39,130.00)		-$ 117,390	$ 1,486,950
47	1730	Overhead Conductors & Devices	$ 63,894			$ 63,894	-$ 3,994	$ (1,997.00)		-$ 5,991	$ 57,903
47	1735	Underground Conduit	$ 870,021			$ 870,021	-$ 49,716	$ (24,858.00)		-$ 74,574	$ 795,447
47	1740	Underground Conductors & Devices	$ 215,252			$ 215,252	-$ 19,568	$ (9,784.00)		-$ 29,352	$ 185,900
12	1611	Computer Software (Formally known as Account 1925)	$ -			$ -	$ -			$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 89,160			$ 89,160	$ -			$ -	$ 89,160
CEC	1806	Land Rights	$ 166,619	$ 7,064.00		$ 173,683				$ -	$ 173,683
47	1808	Buildings	$ 24,936,353	$ 82,630.00		$ 25,018,983	-$ 1,353,815	$ (680,892.00)		-$ 2,034,707	$ 22,984,276
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 6,209,828	$ 275,737.00		$ 6,485,565	-$ 482,068	$ (250,221.00)		-$ 732,289	$ 5,753,276
47	1820	Distribution Station Equipment <50 kV	$ 9,922,834	$ 276,939.00		$ 10,199,773	-$ 767,744	$ (411,336.00)		-$ 1,179,080	$ 9,020,693
47	1825	Storage Battery Equipment	$ 13,722			$ 13,722	-$ 1,306	$ (653.00)		-$ 1,959	$ 11,763
47	1830	Poles, Towers & Fixtures	$ 14,582,754	$ 1,601,920.00		$ 16,184,674	-$ 571,507	$ (347,136.00)		-$ 918,643	$ 15,266,031
47	1835	Overhead Conductors & Devices	$ 10,456,639	$ 1,278,318.00		$ 11,734,957	-$ 497,243	$ (277,660.00)		-$ 774,903	$ 10,960,054
47	1840	Underground Conduit	$ 3,167,642	$ 377,141.00		$ 3,544,783	-$ 436,198	$ (228,373.00)		-$ 664,571	$ 2,880,212
47	1845	Underground Conductors & Devices	$ 12,805,713	$ 333,422.00		$ 13,139,135	-$ 1,026,206	$ (535,648.00)		-$ 1,561,854	$ 11,577,281
47	1850	Line Transformers	$ 10,977,259	$ 1,279,182.00		$ 12,256,441	-$ 510,318	$ (295,574.00)		-$ 805,892	$ 11,450,549
47	1855	Services (Overhead & Underground)	$ 5,360,047	$ 349,553.00		$ 5,709,600	-$ 272,593	$ (150,761.00)		-$ 423,354	$ 5,286,246
47	1860	Meters	$ 4,663,006	$ 83,653.00		$ 4,746,659	-$ 828,414	$ (421,994.00)		-$ 1,250,408	$ 3,496,251
47	1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
12	1925	Compute rSoftware	$ -			$ -				$ -	$ -
10	1930	Transportation Equipment	$ -			$ -	$ -			$ -	$ -
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -			$ -	$ -			$ -	$ -
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 1,542,755	$ 43,067.00		$ 1,585,822	-$ 472,395	$ (239,402.00)		-$ 711,797	$ 874,025
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 12,662,272	$ (450,272.00)		-$ 13,112,544	$ 701,473	$ 371,428.00		$ 1,072,901	-$ 12,039,643
47	2440	Deferred Revenue[5]	$ -			$ -	$ -			$ -	
						$ -				$ -	$ -
		Sub-Total	**$ 95,587,873**	**$ 5,538,354**	**$ -**	**$ 101,126,227**	**-$ 6,669,872**	**-$ 3,543,991**	**$ -**	**-$ 10,213,863**	**$ 90,912,364**
		Less Socialized Renewable Energy Generation Investments **(input as negative)**				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets ***(input as negative)***				$ -				$ -	$ -
		Total PP&E	**$ 95,587,873**	**$ 5,538,354**	**$ -**	**$ 101,126,227**	**-$ 6,669,872**	**-$ 3,543,991**	**$ -**	**-$ 10,213,863**	**$ 90,912,364**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 3,543,991**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Net Depreciation	-$ 3,543,991

Appendix 2-BA

Fixed Asset Continuity Schedule[1]

Accounting Standard	MIFRS
Year	**2017**

			Cost				**Accumulated Depreciation**				
CCA Class[2]	**OEB Account**[3]	**Description**[3]	**Opening Balance**	**Additions**[4]	**Disposals**[6]	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**[6]	**Closing Balance**	**Net Book Value**
N/A	1706	Land Rights	$ 602,307			$ 602,307	$ -			$ -	$ 602,307
47	1725	Poles and Fixtures	$ 1,604,340			$ 1,604,340	-$ 117,390	-$ 39,130		-$ 156,520	$ 1,447,820
47	1730	Overhead Conductors & Devices	$ 63,894			$ 63,894	-$ 5,991	-$ 1,997		-$ 7,988	$ 55,906
47	1735	Underground Conduit	$ 870,021			$ 870,021	-$ 74,574	-$ 24,858		-$ 99,432	$ 770,589
47	1740	Underground Conductors & Devices	$ 215,252			$ 215,252	-$ 29,352	-$ 9,784		-$ 39,136	$ 176,116
12	1611	Computer Software (Formally known as Account 1925)	$ -			$ -	$ -			$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 89,160			$ 89,160	$ -			$ -	$ 89,160
CEC	1806	Land Rights	$ 173,683	$ 2,446.00		$ 176,129				$ -	$ 176,129
47	1808	Buildings	$ 25,018,983			$ 25,018,983	-$ 2,034,707	-$ 682,544		-$ 2,717,251	$ 22,301,732
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 6,485,565	$ 442,651		$ 6,928,216	-$ 732,289	-$ 259,201		-$ 991,490	$ 5,936,726
47	1820	Distribution Station Equipment <50 kV	$ 10,199,773	$ 636,897		$ 10,836,670	-$ 1,179,080	-$ 422,759		-$ 1,601,839	$ 9,234,831
47	1825	Storage Battery Equipment	$ 13,722			$ 13,722	-$ 1,959	-$ 653		-$ 2,612	$ 11,110
47	1830	Poles, Towers & Fixtures	$ 16,184,674	$ 1,380,875		$ 17,565,549	-$ 918,643	-$ 380,278		-$ 1,298,921	$ 16,266,628
47	1835	Overhead Conductors & Devices	$ 11,734,957	$ 873,437		$ 12,608,394	-$ 774,903	-$ 295,592		-$ 1,070,495	$ 11,537,899
47	1840	Underground Conduit	$ 3,544,783	$ 262,089		$ 3,806,872	-$ 664,571	-$ 234,765		-$ 899,336	$ 2,907,536
47	1845	Underground Conductors & Devices	$ 13,139,135	$ 385,581		$ 13,524,716	-$ 1,561,854	-$ 544,636		-$ 2,106,490	$ 11,418,226
47	1850	Line Transformers	$ 12,256,441	$ 1,050,773		$ 13,307,214	-$ 805,892	-$ 323,951		-$ 1,129,843	$ 12,177,371
47	1855	Services (Overhead & Underground)	$ 5,709,600	$ 425,178		$ 6,134,778	-$ 423,354	-$ 160,445		-$ 583,799	$ 5,550,979
47	1860	Meters	$ 4,746,659	$ 213,868		$ 4,960,527	-$ 1,250,408	-$ 431,912		-$ 1,682,320	$ 3,278,207
47	1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
12	1925	Compute rSoftware	$ -			$ -				$ -	$ -
10	1930	Transportation Equipment	$ -			$ -	$ -			$ -	$ -
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -			$ -	$ -			$ -	$ -
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 1,585,822	$ 4,186		$ 1,590,008	-$ 711,797	-$ 240,584		-$ 952,381	$ 637,627
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 13,112,544	-$ 996,060		-$ 14,108,604	$ 1,072,901	$ 389,507		$ 1,462,408	-$ 12,646,196
47	2440	Deferred Revenue[5]	$ -				$ -				
						$ -				$ -	$ -
		Sub-Total	**$ 101,126,227**	**$ 4,681,921**	**$ -**	**$ 105,808,148**	**-$ 10,213,863**	**-$ 3,663,582**	**$ -**	**-$ 13,877,445**	**$ 91,930,703**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 101,126,227**	**$ 4,681,921**	**$ -**	**$ 105,808,148**	**-$ 10,213,863**	**-$ 3,663,582**	**$ -**	**-$ 13,877,445**	**$ 91,930,703**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 3,663,582**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 3,663,582

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard	MIFRS
Year	**2018**

			Cost				**Accumulated Depreciation**				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
N/A	1706	Land Rights	$ 602,307			$ 602,307	$ -			$ -	$ 602,307
47	1725	Poles and Fixtures	$ 1,604,340			$ 1,604,340	-$ 156,520	-$ 39,130		-$ 195,650	$ 1,408,690
47	1730	Overhead Conductors & Devices	$ 63,894			$ 63,894	-$ 7,988	-$ 1,997		-$ 9,985	$ 53,909
47	1735	Underground Conduit	$ 870,021			$ 870,021	-$ 99,432	-$ 24,858		-$ 124,290	$ 745,731
47	1740	Underground Conductors & Devices	$ 215,252			$ 215,252	-$ 39,136	-$ 9,784		-$ 48,920	$ 166,332
12	1611	Computer Software (Formally known as Account 1925)	$ -			$ -	$ -			$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 89,160			$ 89,160	$ -			$ -	$ 89,160
CEC	1806	Land Rights	$ 176,129	$ 1,621.00		$ 177,750				$ -	$ 177,750
47	1808	Buildings	$ 25,018,983	$ 63,099		$ 25,082,082	-$ 2,717,251	-$ 683,596		-$ 3,400,847	$ 21,681,235
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 6,928,216	$ 122,779		$ 7,050,995	-$ 991,490	-$ 266,269		-$ 1,257,759	$ 5,793,236
47	1820	Distribution Station Equipment <50 kV	$ 10,836,670	$ 526,035		$ 11,362,705	-$ 1,601,839	-$ 437,296		-$ 2,039,135	$ 9,323,570
47	1825	Storage Battery Equipment	$ 13,722			$ 13,722	-$ 2,612	-$ 653		-$ 3,265	$ 10,457
47	1830	Poles, Towers & Fixtures	$ 17,565,549	$ 1,586,992		$ 19,152,541	-$ 1,298,921	-$ 413,255		-$ 1,712,176	$ 17,440,365
47	1835	Overhead Conductors & Devices	$ 12,608,394	$ 1,034,718		$ 13,643,112	-$ 1,070,495	-$ 311,493		-$ 1,381,988	$ 12,261,124
47	1840	Underground Conduit	$ 3,806,872	$ 214,630		$ 4,021,502	-$ 899,336	-$ 239,532		-$ 1,138,868	$ 2,882,634
47	1845	Underground Conductors & Devices	$ 13,524,716	$ 352,285		$ 13,877,001	-$ 2,106,490	-$ 553,859		-$ 2,660,349	$ 11,216,652
47	1850	Line Transformers	$ 13,307,214	$ 1,272,911		$ 14,580,125	-$ 1,129,843	-$ 352,997		-$ 1,482,840	$ 13,097,285
47	1855	Services (Overhead & Underground)	$ 6,134,778	$ 457,483		$ 6,592,261	-$ 583,799	-$ 171,479		-$ 755,278	$ 5,836,983
47	1860	Meters	$ 4,960,527	$ 146,036		$ 5,106,563	-$ 1,682,320	-$ 443,908		-$ 2,126,228	$ 2,980,335
47	1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
12	1925	Compute rSoftware	$ -			$ -				$ -	$ -
10	1930	Transportation Equipment	$ -			$ -	$ -			$ -	$ -
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -			$ -	$ -			$ -	$ -
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 1,590,008	$ 29,766		$ 1,619,774	-$ 952,381	-$ 241,432		-$ 1,193,813	$ 425,961
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 14,108,604	-$ 450,000		-$ 14,558,604	$ 1,462,408	$ 407,583		$ 1,869,991	-$ 12,688,613
47	2440	Deferred Revenue[5]	$ -				$ -				
						$ -				$ -	$ -
		Sub-Total	**$ 105,808,148**	**$ 5,358,355**	**$ -**	**$ 111,166,503**	**-$ 13,877,445**	**-$ 3,783,955**	**$ -**	**-$ 17,661,400**	**$ 93,505,103**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 105,808,148**	**$ 5,358,355**	**$ -**	**$ 111,166,503**	**-$ 13,877,445**	**-$ 3,783,955**	**$ -**	**-$ 17,661,400**	**$ 93,505,103**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 3,783,955**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Net Depreciation	-$ 3,783,955

APPENDIX 2

PUC Distribution Inc. Distribution System Plan

PUC Distribution Inc.

Distribution System Plan

2018-2022

Prepared by

METSCO
MAKING IT POSSIBLE

March 21, 2018

File: PUC DSP 2018-03-21 final.docx

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1 Introduction

PUC Distribution Inc. (PUC Distribution) has prepared this Distribution System Plan ("DSP") in accordance with the Ontario Energy Board's ("OEB's") Chapter 5 - Consolidated Distribution System Plan Filing Requirements, dated March 28, 2013 (the "Filing Requirements") as part of its 2018 Cost of Service Application (the "Application").

PUC Distribution is licenced to distribute electricity in its service territory which includes most of the City of Sault Ste. Marie, Batchewana First Nation (Rankin Reserve), Prince Township and parts of Dennis Township. Its service territory covers a service area of approximately 342 square kilometers, with a combined population of approximately 75,300. The service territory includes approximately 29,700 residential customers and approximately 3,800 general customer services for a total of approximately 33,500 customers.

The DSP was prepared to provide to the OEB and all interested stakeholders:

- An overview of PUC Distribution's asset planning objectives and goals;
- A review of PUC Distribution's operational performance in the five-year historical period;
- A preview of PUC Distribution's planned expenditures for the forecast period aimed at improving its asset-related performance to achieve the four performance outcomes established by the OEB; and
- A detailed justification of PUC Distribution's planned capital expenditures in the test year.

This DSP covers a planning horizon of five years starting in the test year, which is 2018 in the case of this filing. Employing this long-term approach requires PUC Distribution to consider future customer needs and any required changes to its distribution system in advance, thereby enhancing PUC Distribution's ability to plan ahead and respond to the evolving needs of customers in a timely manner, while managing and leveling the impacts of these expenditures on consumer rates to maintain affordability of its service.

Taking a performance-based approach for regulating electricity distributors under the Renewed Regulatory Framework for Electricity (RRFE), the OEB has established the following four performance outcomes to be achieved by electricity distributors:

- **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

PUC Distribution’s vision is to be recognized as a progressive electric distribution company committed to delivering value, innovation, prosperity and excellence. In order to accomplish this, PUC Distribution’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. Our DSP has been informed and influenced through multiple avenues of customer engagement although system asset investment decisions are still primarily influenced by condition based factors to ensure a safe system and maintain or enhance reliability which customers value very highly. Our most recent customer survey focused on the Cost of Service application and the rate increase being sought in our application. Background on cost drivers and cost increases since our last application in 2012 were part of the education and feedback areas brought forward to customers. An integrated approach has been employed for investment planning with all of the investments pertaining to the following categories planned and optimized together:

- System Access,
- System Renewal,
- System Service, and
- General Plant.

As defined by OEB in its Chapter 5 filing requirements,

System Access investments are modifications to a distributor’s distribution system a distributor is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the distribution system;

System Renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor’s distribution system to provide customers with electricity services;

System Service investments are modifications to a distributor’s distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements including smart grid development; and

General Plant investments are modifications, replacements or additions to a distributor's assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities.

The DSP contents are organized using the Ontario Energy Board's Chapter 5 - Consolidated Distribution System Plan Filing Requirements. Section 2 provides an overview of the DSP and describes the process employed in its development, i.e. stakeholder consultations, collaboration with municipal/regional governments and transmitters, performance measurements and monitoring metrics. Section 3 describes in detail the asset management process employed to determine the scope of capital investments into asset sustainment and prioritize these investments into various assets. Section 4 documents the overall capital expenditure plan covering System Access, System Renewal, System Service, and General Plant, including justification for investments. Section [5.4.2] of the OEB's DSP filing requirements mandates detailed description of projects to be provided above the Distributor's materiality threshold.

The materiality threshold for PUC Distribution is $90,000 and detailed descriptions of specific projects exceeding the materiality threshold are provided in Section 4.5.2 and Appendix G. Other pertinent information relevant to this DSP is included in the Appendices.

2 Distribution System Plan [5.2]

Throughout this document, section headings are followed by references in square brackets, e.g.: [5.2], to cross reference the information provided in the DSP back to the OEB requirements, as indicated in the OEB document ‘Filing Requirements for Electricity Transmission and Distribution Applications – Chapter 5 – Consolidated Distribution System Plan Filling Requirements’.

2.1 DSP Overview [5.2.1]

2.1.1 How Key Elements of the DSP Support Planning Objectives

> ***Key elements of the DSP that affect its rates proposal, especially prospective business conditions driving the size and mix of capital investments needed to achieve planning objectives [5.2.1 a]***

Table 1 shows at a glance the customer mix served by PUC Distribution. In addition to the customer count indicated in the table, additional loads served from the distribution system include approximately 9314 streetlights and 295 unmetered scattered loads.

Table 1: Customer Count by Type

Customer Type	# of Customers
Residential	29708
GS<50	3419
GS>50	360
Total	33487

As indicated in Figure 1, the customer base of PUC Distribution is comprised of approximately 89% residential and 11% general service customers.

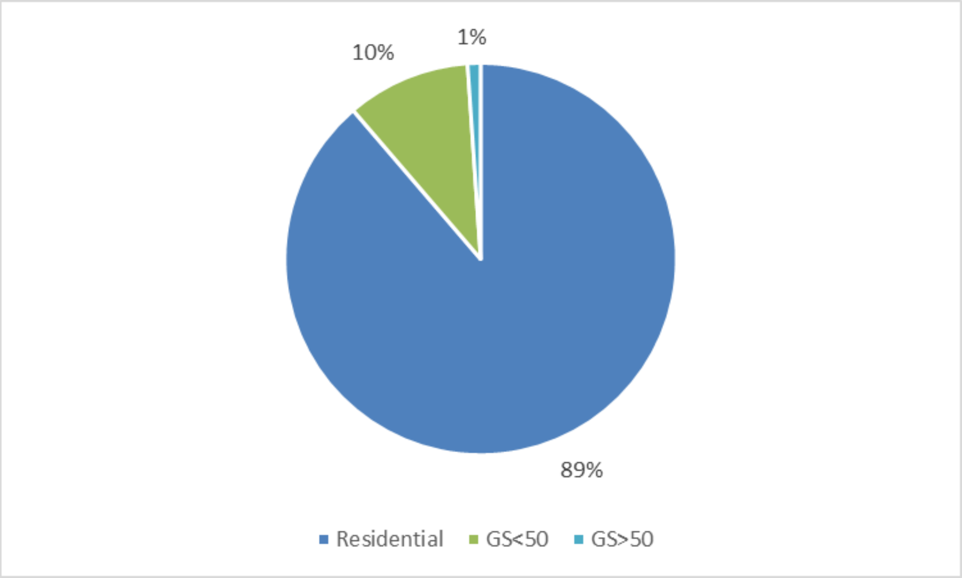


Figure 1: Customer Mix by Type

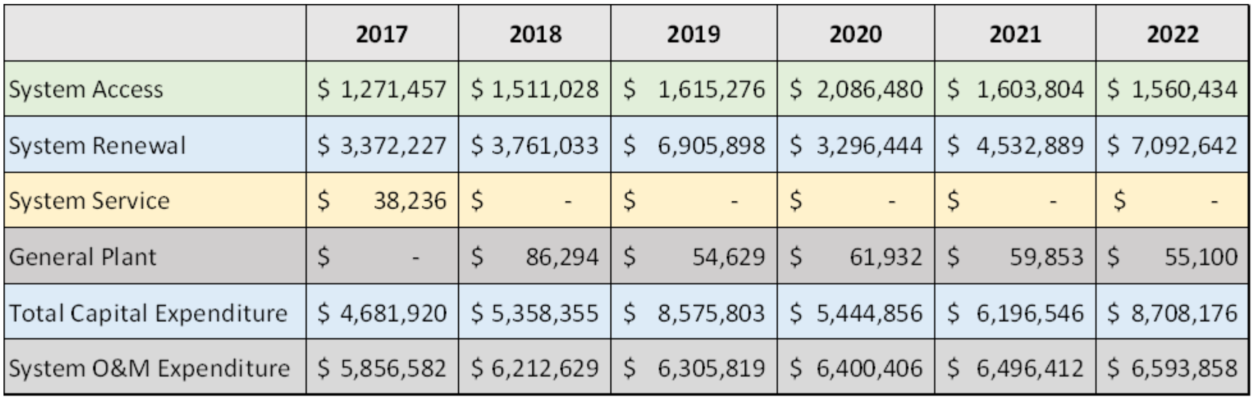
Historically, the local economy in PUC Distribution's service territory has been dominated by steelmaking. This industry has not experienced growth over the recent past and therefore, there hasn't been significant growth in the region's population. This trend is expected to continue during the next five-year period, covered by this DSP. Historically, electricity has been used for space heating in this region and therefore load on the electricity distribution grid peaks during the winter. For example, during the period from 2010 to 2014, the winter peak load was approximately 55% higher than the summer peak load. Shifting of space heating from electricity to natural gas, combined with the multiple energy conservation and demand management (CDM) initiatives implemented by residential and general service customers and expansion of natural gas distribution network in the region, has resulted in a steady decline in the peak demand on the electrical grid and this trend is expected to continue. There are currently no capacity constraints in the supply system that would prevent connection of anticipated load or generation customers during the next five years and therefore no investments are required to mitigate capacity constraints during that period. During recent years, the community has invested a significant amount of effort to diversify the local economy and these diversification efforts have resulted in development and growth of a call center industry. There has been significant effort to grow the tourism industry, with development of a major Casino in the downtown. The corporate head office of Ontario Lottery and Gaming Corporation (OLG) is also located in Sault Ste. Marie and Sault Ste. Marie has become a regional hub to provide services for the surrounding rural communities. Availability of reliable electricity supply at affordable prices is an essential ingredient, needed for the region's diversification efforts to succeed.

A significantly large portion of the existing infrastructure employed on PUC Distribution's supply network has reached a service age beyond its typical useful life. Through a recently completed asset condition assessment exercise, a significantly large fraction of critical power supply infrastructure components employed at distribution stations, overhead lines and underground distribution system have been determined to be in “poor” or “very poor” operating condition. In the absence of major investments into asset renewal, the existing infrastructure presents high risk of failure in service, affecting supply system reliability and public safety. However, renewal and replacement of all infrastructure components determined to be in “poor” or “very poor” condition during the next five years, would be difficult to manage through PUC Distribution’s resources and it would lead to unaffordable increase in retail rates.

Given that the highest priority concern from almost all customer engagement activities is the high cost of electricity bills and an increasing worry over affordability followed by the importance placed on reliability and customer communications, our challenge is to seek an optimized balance of these somewhat opposing factors. Therefore, in preparing this DSP, PUC Distribution has focused on prioritizing the investments into renewal of the most critical infrastructure components, to achieve the balance required between keeping the power supply reliability from degrading while maintaining the electricity distribution rates at affordable levels. Advanced technology will be incorporated in system design selectively, where benefits outweigh the costs, during implementation of asset renewal projects, to meet the current and future needs of the customers, to improve operating efficiency and to support the integration of renewables and smart grid technologies.

The capital investment plan is discussed in detail in Section 4, but a summary of the proposed investment is presented in Table 2 below to provide context as to the level of proposed investment under each category:

Table 2: Proposed Capital Investments During the DSP Implementation Period



	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 Capital Expenditure	$ 4,681,920	$ 5,358,355	$ 8,575,803	$ 5,444,856	$ 6,196,546	$ 8,708,176
System O&M Expenditure	$ 5,856,582	$ 6,212,629	$ 6,305,819	$ 6,400,406	$ 6,496,412	$ 6,593,858

Although a majority of the investments proposed in this DSP fall in the System Renewal category, the overall capital investment plan incorporates investment to the appropriate degree in each of the four general categories: (1) System Access; (2) System Renewal; (3) System Service and (4) General Plant.

The planned investments into System Access are intended to facilitate modest anticipated growth to allow connection of new customers to the grid, meeting requests of existing customers for increase in service size and meeting PUC Distribution's regulatory obligations for relocating distribution lines when requested by the municipality and for re-calibration and renewal of the revenue meters in compliance with the Measurement Canada regulations. The indicated investments in the System Access category represent net expenditure by PUC Distribution, after third party contributions have been subtracted from the total cost.

The planned investments into System Renewal are intended to mitigate a number of specific prevailing risks to distribution system reliability, public safety and adverse environmental impacts, due to very poor condition of some key assets, the in-service failure of which would lead to severe consequences.

Although no planned investments have been included in the System Service category, a number of investments in the renewal category, particularly those involving station rebuilds, line rebuilds and SCADA and protection upgrades, will also introduce smart grid features, including opportunities for greater automation, improved access for connection of renewable generation and improved access for joint-use of distribution facilities. Therefore, these investments can be considered to serve multiple roles: System Access and System Service in addition to System Renewal.

PUC Distribution leases its motor vehicle assets rather than owning them, therefore a relatively small capital investment is required for renewal of General Plant, needed to cover minor building renewal items. The scope and timing of the investments in each category has been determined by taking into account all information available at the time of preparation of the distribution plan.

System Access

The planned investments in the System Access category include expenditure required by PUC Distribution to meet its regulatory obligations. These investments consist of four main components:

- new subdivisions, new services and upgraded services to meet customer needs;
- line relocations required in conjunction with municipal road reconstruction programs;
- investments to add new meters and maintain existing revenue meters compliant with regulations; and
- "make-ready work", related to joint use applications by 3rd party telecommunications companies.

During the past five years, demand for new services has been relatively flat and there has not been a significant change in the number of customers served by PUC Distribution. There was modest growth in residential subdivision development in PUC Distribution's service territory, during 2012 and 2013, but extremely limited subdivision development activity took place from 2014 to 2016. During the past three years, demand for new services in existing subdivisions has also decreased moderately likely due to the economic difficulties encountered by the steel industry, which remains the major driver of local economy in PUC Distribution's service territory. At present, there is no backlog of customers requiring new services within PUC Distribution service areas.

A modest recovery in the local economy is anticipated during the next five years, primarily driven by macro-economic factors, resulting in a small increase in requests for new services from the existing levels. Discussions with developers indicate minimal growth in 2017 and modest growth in 2018 and 2019. There are presently two residential subdivision developments being planned for 2018 and 2019, and these will require capital investments in System Access category to meet the requests for new services.

Road reconstruction projects undertaken in the municipality require relocation of some power distribution lines, requiring capital investments by PUC Distribution, from time to time. PUC Distribution has employed the City's 5-year development plan to estimate capital expenditure required for line relocates and rebuilds to accommodate municipal infrastructure projects. The municipal development plans are subject to change, so there is some risk that the actual required expenditure in this category may be different from the amounts indicated in the DSP.

All existing residential and general service customers (< 50 kW) were equipped with smart meters between 2009 and 2010. PUC Distribution owns approximately 33,500 revenue meters, installed on its customers' premises for the purpose of measuring electric consumption and demand of connected load for the purpose of billing. PUC Distribution plans to sample 600 meters in 2019, 200 in 2020 and 80 in 2021 all in accordance with Measurement Canada's "S-S-05—Performance Requirements Applicable to Meters Granted a Conditionally Lengthened Initial Reverification Period under S-EG-01" - sample its meter population to acquire an extension of up to 8 years. In addition, revenue meters will also be required to replace meters failed in service and based on the historic experience, the failure rate of revenue meters is expected to be approximately 0.6% per year. PUC Distribution is also required to equip all general service customers with >50kW to <500kW demand with MIST meters.

There are also steady requests from communication network companies that share PUC Distribution's network for "make ready work" and flow of such requests is anticipated to continue at the same pace. However there exists the possibility for an extremely significant demand change with relatively short notice as was experienced in the previous rate application period due to a 'fibre to the home' project that covered a large portion of PUC Distribution's system. The System Access category investments, therefore, also includes an allowance for the net contribution required from PUC Distribution.

System Renewal

PUC Distribution engaged METSCO Energy Solutions in 2016 to perform a comprehensive condition assessment of all distribution system assets and develop an asset management plan to mitigate risks associated with in-service failure of assets. The asset condition assessment, included in Appendix B, provides detailed results of the asset condition assessment initiative completed in 2016.

As described in greater detail in Section 3.2.3, those assets, the condition of which has already reached a state of impairment that they present a very high risk of failure in service are assigned "very poor" condition and those assets with significant impairment causing performance to degrade below acceptable level and presenting a high risk of failure in service in the absence of major repair or rehabilitation or renewal, are assigned "poor condition".

The scope of capital investments planned in the System Renewal category has been determined with the objective of keeping power supply reliability from deteriorating below an acceptable level. In order to keep the overall investment envelope for this DSP within a range, which would not result in retail rates escalations beyond the affordability of PUC Distribution's customer base and which could be successfully implemented without stretching beyond limit PUC Distribution's financial resources; investments required for renewal and rehabilitation of the assets found in "very poor" or "poor" condition have been spread out over a time period of longer than five years and assets with highest consequence of failure in service, have been prioritized for renewal or rehabilitation, during the next five years. Prioritized investments into asset renewal and rehabilitation included in this DSP are summarized below:

Due to the advanced service age, combined with "poor" and "very poor" operating condition of a vast majority of the power transformers, switchgear, protection and control equipment and other miscellaneous assets employed at both of the 115/34.5 kV transformer stations (TS-1 and TS-2), both stations require complete rebuilds with new power transformers, switchgear, protection and control equipment. However, rebuilding of these two transformer stations requires significant front-end planning and engineering to comprehensively assess all available alternatives with the objective of selecting the optimal alternative for re-development. Each of these stations employ equipment redundancies in their design, each station with four power transformers, which presently allows PUC Distribution to manage the reliability risk even during an 'N-1' contingency. Therefore, this 5-year DSP does not include funding to cover the construction cost of these two transformer stations, but includes capital investment required to perform a planning and engineering study to review all practical development options through completion of conceptual designs to identify the optimal station development alternative, for implementation during 2023 to 2027. Refurbishment options are not feasible as asset deterioration is broad-based at these two sites. Current observations indicate that a significant 'total rebuild' capital investment will need to be made to fully address the matter at least at one of the two sites during

2023-2027 rate application period and at the second during either that same or the subsequent 5-year period.

The condition of the power transformers and switchgear at seven of the twelve existing 34.5/12.5 kV as well as both remaining 4.2 kV distribution stations has been determined to be in “poor” or “very poor” condition. This DSP includes funding for upgrade of the distribution lines supplied from the 4.2 kV stations to 12.5 kV stations, which would allow the last remaining 4.2 kV stations to be retired from service after the voltage upgrade of distribution lines has been completed. It also includes provision for rebuilding two distribution stations during the five-year implementation period; one of which will replace both the 4.2 kV stations and the second will replace one of the existing 34.5/12.5 kV stations. These distribution station rebuild projects have been prioritized by taking into consideration the relative risk of equipment failures and the anticipated consequences of equipment failures on supply system reliability, public safety and operating costs. Subsequent to station renewal in this DSP and the recent retirement of Substation 14, five distribution stations will remain for inclusion in the renewal program during the next two DSP periods (2023 to 2032).

For the two transformer stations and the distribution stations found in “poor” or “very poor” condition but not included in the renewal program in the current DSP, PUC Distribution plans to manage the risk of equipment failures through proactive monitoring and testing of equipment. Accordingly, this DSP includes funding for proactive repair, refurbishment and component replacement activities as an outcome of station inspections as well as to address unplanned equipment failures. Annual funds budgeted are based on the past 5 years expenditures and are intended to maintain system reliability at current levels. In the event of a major equipment failure such as the loss of a distribution station or feeder, contingency plans are in place to ensure that load can be readily transferred to an alternate supply while repairs or replacements are completed. This risk based refurbishment strategy allows PUC Distribution to minimize expenditures over the life cycle of the assets, while meeting targeted performance levels including system reliability.

PUC Distribution’s primary overhead distribution network employs approximately 391 km of 3-phase and approximately 230 km of 1-ph lines. Approximately 28.5% of the overhead lines will reach the end of their typical useful life during the next five years. As the lines approach the end of their design life, all line components including wood poles, mounting hardware and conductors experience degradation of strength and pose a high risk of failure in service when subjected to design loading during wind and ice storms. To mitigate this risk, these lines will require rebuild with new poles and conductors. However, rather than proposing re-construction of all overhead lines that have reached the end of their design life, this DSP includes a small subset of the lines, prioritized for renewal based on the risk of failure in service. The lines included for renewal in this DSP have been prioritized by considering the impact of critical component failures on public safety, supply reliability and operating costs. Accordingly, in this

DSP priority for line re-construction has been given to: (a) replacement of poles in “very poor condition, (b) line sections built with restricted conductor, and (c) line sections determined to be in “very poor” condition and currently operating at 4 kV, which will undergo voltage upgrade upon reconstruction.

Copper and aluminum conductors with smaller cross-section area, and more specifically #6 AWG and #4 AWG (copper or aluminum) conductors have lower tensile strength in relation to larger conductors typically used in overhead line construction. Under tension, the tensile strength of these smaller cross-section conductors further degrades with service age. These conductors are known to fail in service and when they fail it creates a very serious safety risk for public when live conductors fall to the ground. #6 and #4 AWG conductors are no longer used for applications requiring conductor tensioning over full spans, and virtually all Canadian utilities have adopted programs to proactively phase out lines built previously with restricted conductors.

PUC Distribution had identified approximately 8 km of 3-phase lines and approximately 60 km of 1-phase lines on its distribution network, constructed with restricted conductors and adopted a program to phase out restricted conductor lines starting in 2010. Up to the end of 2015, approximately 26% of the lines with restricted conductor had been phased out. Work on reconstruction of the remaining lines with restricted conductor is scheduled to continue during this 5-year DSP, with a target date of 2027 for complete elimination of all restricted conductor lines from the network.

There are approximately 12,600 wood poles and about 80 other types of poles (including steel, concrete and fiberglass) employed on PUC Distribution’s overhead lines. In 2016, approximately 328 poles had reached the service age of more than 60 years and an additional 857 poles had reached the service age more than 50 and less than 60 years. Wood poles experience degradation in strength due to wood decay with service age, but the relationship between pole strength and service age is not linear. In order to identify poles in “very poor” condition PUC Distribution periodically conducts in-situ testing of poles and these poles are then targeted for replacement. This DSP provides funding for annual renewal of approximately 30 poles determined to be in “very poor” condition.

Overhead lines employed on the 4 kV distribution system are the oldest infrastructure components on PUC Distribution’s power supply network. Most of these lines have reached a service age of 50 or 60 years, well past their design life and they present the highest risk of failure in service. PUC Distribution has been gradually removing the 4 kV lines from its network by rebuilding the lines with voltage upgrades to 12.5 kV. This DSP provides funding for the voltage upgrade program with a target date of 2022 for completion of the program.

Because the planned overhead line renewal programs described in paragraph (iv), (v) and (vi) above target a sub-set of the overhead lines determined to be in “poor” or “very poor” condition, it is expected that some line sections would experience failures during storms and require emergency repairs to restore power. Therefore, this DSP includes funding to perform emergency repairs and refurbishment upon line failures in service.

For overhead distribution transformers, a “run to failure” strategy is proposed, where a transformer is replaced only after failure. This DSP includes investments to replace distribution transformers after they fail. Current PCB regulations in Canada permit the use of distribution transformers containing PCB content in oil of up to 50 parts per million and this use can continue up to December 31, 2025. All distribution transformers must be below 50 parts per million after December 31, 2025. To comply with this regulation, distribution utilities will need to either (a) test all suspect transformers (purchased prior to 1984) for PCB content and replace those containing PCBs above the threshold, or (b) replace all suspect transformers (purchased prior to 1984). This DSP includes budgetary provision for testing suspect distribution transformers for PCB content but replacing transformers that fail the PCB test have been deferred to beyond 2022.

The underground distribution network at PUC Distribution employs approximately 75 km. of 3-phase cable circuits and approximately 47 km of 1-phase and 2-phase cable circuits. Approximately 25% of the cable has reached service age of greater than 40 years. There are no practical tests available which could be economically performed in field to accurately assess the remaining useful life of cables. However, XLPE insulated cables, which are typically employed on underground distribution systems; generally begin to experience an increase in failure rates when they get past 40 years of service age. It is also noteworthy that a vast majority of the cables installed prior to 1990 were installed in direct buried configuration. Cable failures in direct buried configurations have significantly larger impact on reliability than failures that occur where cables are installed in duct. All cable circuits past 40 years of service age are considered in poor condition. This DSP includes funding for proactive replacement of only a part of underground cables determined to be in very poor and poor condition, with priority given to direct buried cable circuits as well as in voltage conversion areas. However, it is expected the underground cables will require more significant ‘ramping up’ of investment beyond 2022 to keep the failures rates at acceptable levels.

Most of the cables employed on 4 kV system are past their 40-year typical useful service life and these cables are planned to be removed from service when these service areas are upgraded to 12.5kV.

For switching of underground circuits, PUC Distribution Inc. employs live-front pad-mounted switchgear as well as K-bar junction boxes. Based on the service age and visual inspections, five of the pad mounted switchgear units and 89 of the K-bar units were determined to be in poor or very poor condition in 2016. This DSP includes funding for the replacement of two pad-mounted switchgear units but no funding for renewal of the K-bar units. Upon renewal, the live front switchgear will be replaced with dead front switchgear, providing enhanced worker safety.

PUC Distribution’s underground distribution system employs concrete chambers for various functions, including cable pull-boxes and manholes, mounting bases for switchgear and K-bar junctions, submersible transformer vaults, splice vaults and general-purpose equipment vaults. Approximately 23% of the chambers are currently more than 50 years old. Physical inspections of the concrete structures indicate a large percentage of these old vintage chambers are functionally obsolete. The submersible transformer vaults and splice vaults present a challenge in that outages are required to safely complete maintenance work thereby increasing costs and inconveniencing customers. Accordingly, funds have been included to make progress in the replacement of these vaults.

System Service

Because the existing plant has adequate capacity without any constraints to allow connection of new loads and generation from renewables during the next five years, this DSP does not include investments to mitigate capacity constraints.

General Plant

Approximately 5 years ago PUC consolidated all of its administrative offices and operational buildings into a newly constructed integrated facility and the retired aging facilities were put up for sale. For the most part the new facility is in excellent condition and meets all functional needs so only minimal incremental building infrastructure investments have been considered in this DSP. The entire motor vehicle fleet used for operations is owned by PUC Distribution Inc.’s non-regulated affiliate services company PUC Services Inc. Consequently, a modest level of capital investment for building improvements and refurbishment is required in this area. Investments in General Plant are aimed at improving worker productivity, operating efficiency and employee safety.

Key Benefits of Investments

The capital investments planned for the 2018 to 2022 period are expected to yield the following benefits:

The investments into System Access category would allow PUC Distribution to meet its obligations to serve new customers, relocate lines in public right-of-way, upon receipt of requests for such services, perform “make ready” work for allowing third party attachments of electricity distribution poles and to have adequate supply of revenue meters to comply with the requirements of the Distribution System Code and Measurement Canada.

The investments into System Renewal will reduce the risk of critical assets' failure in service and help sustain the reliability at acceptable levels and ensure public safety. These investments will also help avoid an increase in operating costs by eliminating the increase in extent of emergency repairs upon asset failures. Retiring from service the distribution system infrastructure operating at 4 kV will eliminate duplication in spare part requirements and will result in improved operating efficiency.

Investments in General Plant are aimed at improving worker productivity, operating efficiency and employee safety.

2.1.2 Sources of Cost Savings Derived from Good Planning

Sources of cost savings expected to be achieved over the forecast period through good planning and DS Plan execution [5.2.1 b]

Cost savings have been considered through good planning and will be achieved through execution of this distribution plan:

Through careful evaluation of the risks, projects are prioritized for implementation to mitigate higher level risks during this DSP implementation period, while deferring the projects with lower level risks or risks that can be managed through alternative cost-effective mitigation measures. For example, although equipment at both of the transformer stations has been determined to be in poor and very poor condition, due to redundancy in their design, it has been possible to defer the approximately $25 million of the required investments for their rebuild. All practical options will be explored through a comprehensive planning and engineering study to identify the optimal station development alternative with highest economic value, for implementation. Subsequent to the implementation of this DSP, approximately $22 million of investments required for redevelopment of the five remaining distribution stations, where the equipment has been determined to be in poor condition has been deferred and priority has been given to address only the stations where incidents of equipment failure present risk of the highest consequence. In case of the underground distribution system, cables in direct buried configurations present higher risk upon failure in relation to cables installed in duct and therefore have been a given a priority in the cable renewal program and the required investments for renewal of cables in poor condition but installed in duct have been deferred. Cost savings derived from these initiatives have not been quantified because the value is based on the frequency and severity of equipment end of life failures, variables which are not measurable. However it is reasonable to expect that the 'bathtub curve' effect for reliability relied upon in asset life cycle planning across many industries is applicable in the case of these assets and that they are presently reaching the end of their cycle.

The reliability improvements through investments into infrastructure renewal will yield cost savings for customers through avoided power interruptions. Also, the deferral of investments, where possible, will yield savings in interest and depreciation costs, which will help reduce escalation in retail rates. Estimates of the deferred capital expenditures are provided in paragraph (a) above. PUC Distribution is unable to quantify the customer savings due to capital deferrals and also from avoided power interruptions at this time because customer reliability valuation surveys have not been performed.

Investments into System Renewal will reduce the number of in-service failure of assets and thus reduce the risk of emergency repair costs from going up. Considering the poor and very poor condition of infrastructure, in the absence of the investments proposed under System Renewal in this DSP, the emergency repair costs are expected to accelerate during the next five years.

Investments into infrastructure renewal will reduce the number of catastrophic equipment failures causing damage, the potential for injury to the public and reduce the risk of third party claims against PUC Distribution. It is impossible to predict the quantity of equipment failures that will result in third party claims and any associated costs or savings.

Proposed investments into General Plant will ensure efficiency of operations and reduce the risk of operating costs from going up. No savings are expected to result from this investment category but are expected to maintain worker productivity and work place safety at required levels.

2.1.3 Period Covered by DSP

Period covered by the Distribution System Plan (historical and forecast) [5.2.1 c]

This DSP covers a 5-year forecast period from 2018 to 2022. It includes historic financial expenditure for five complete years (2012 to 2016) and historic operating performance of PUC Distribution from 2012 to 2016.

2.1.4 Vintage of Information

Vintage of information on investment drivers used to justify investments identified in the application [5.2.1 d]

The Asset Management Plan as presented in Appendix B was finalized on September 30, 2016. This DSP is premised upon information contained in that document and is supplemented with additional information available from asset renewal projects completed as of September 30, 2017.

2.1.5 Important Changes to the Distributor's DSP

> ***Indication of important changes to the distributor's asset management processes (e.g. enhanced asset data quality or scope; improved analytic tools, process refinements; etc.) since the last DS Plan filing [5.2.1 e]***

This is PUC Distribution's first DSP under the new filing requirements. The methodology employed to support the level of investments and prioritize the investments into specific project categories differs from the methodology used in PUC Distribution's previous submission to OEB, in the following ways:

Enhanced Methodology

- The methodology used for prioritizing investments in this DSP, employs an objective, risk-based approach, which results in determining the scope and timing of investments to match the level of risk intended to be mitigated through the investment. To achieve improvements in this area over previous methodologies, Engineering resources were focused to a greater extent on developing associated programs and plans in areas including voltage conversion, restricted conductor replacement and station rebuilds.

- For evaluation of the risk associated with aging assets, all available data relevant to the present condition of assets, i.e. demographic information, results of field inspections and in-situ testing has been used. This methodology has been enhanced by including better quality and more extensive asset condition data collected over the past five years.

New Methodology

- The methodology used for investment planning in this DSP integrates customer preferences and creates an optimal balance between the service levels provided by the distribution assets and the cost of services, meeting customers' needs of reliable power supply at affordable prices. The previous asset management plan did not consider customer feedback through a formal customer engagement process.

2.1.6 Interdependency of DSP to Ongoing Activities or Future Events

> ***Aspects of the DS Plan that relate to or are contingent upon the outcome of ongoing activities or future events, the nature of the activity (e.g. Regional planning process) or event (Board decision, LTLT) and the expected dates by which such outcomes are expected or will be known [5.2.1 f]***

None of the investments proposed in the DSP are contingent upon the outcome of ongoing activities or future events. The level of actual investments for System Access may slightly deviate year-to-year from the proposed investment levels, depending upon the number of stakeholder requests received for services, but such deviations are expected to be minor and the overall expenditure level during the next five years is not expected to be significantly different from what is proposed in this DSP. Since none of the investments involve addressing constraints in the transmission system or upstream distribution system and since there are no embedded distributors served from PUC Distribution's distribution system, the regional planning process has no impacts on this distribution plan and proposed investments.

2.2 Coordinated Planning with Third Parties [5.2.2]

Before preparing this DSP, PUC Distribution has consulted with all stakeholders affected by the DSP, with the objective of accurately assessing their needs and to confirm the adequacy of existing capacity of the distribution system; so that the investments could be focused into areas of the greatest need. The results of coordinated planning with third parties are documented in this section, by addressing the following questions for each consultation:

- the purpose of the consultation;
- whether the distributor initiated the consultation or was invited to participate in it;
- the other participants in the consultation process;
- the nature and prospective timing of the final deliverables, that are expected to result from or otherwise be informed by the consultation; and
- an indication of whether the consultation has or is expected to affect the distributor's DS Plan as filed and if so, a brief explanation as to how.

This distribution plan has been prepared through a coordinated planning process with all major stakeholders. The stakeholders consulted by PUC Distribution during preparation of the DSP include:

- customers;
- municipal governments;
- CDM program partners; and
- OPA/IESO

2.2.1 Description of Consultations [5.2.2 a]

2.2.1.1 Customer Engagement

Purpose of Consultation

PUC Distribution conducts customer consultations to gather customers' opinions related to its services and to ensure that the customers' needs and preferences are taken into account during development of long term plans. PUC Distribution has conducted both formal and informal community engagement activities with its customers over the last five (5) years.

Who Initiated the Consultation?

All consultations with the customers were initiated by PUC Distribution, either through its own staff or through consultants.

Other Participants in Consultations

Other participants included residential and general service customers.

Nature and Timing of Final Deliverables

The final deliverables from these consultations are included in the form of stand-alone reports in Appendix C and Appendix H.

Consultations Impact on this DSP

Customer feedback has been integrated into the preparation of this DSP. While a vast majority of PUC Distribution customers are fully satisfied and pleased with the power supply reliability, a majority of the customers are also sensitive to an increase in retail rates. Customer sensitivity to the retail rate increases has been taken into consideration in this DSP, by accepting some risk of asset failures in service and by deferring a number of projects in the asset renewal category and only including a relatively small number of projects in the current investment plan, which present the highest risk of asset failures during the next five years.

Brief Description of Customer Engagements

PUC Distribution believes that customer engagement is the backbone of its community-driven operations. PUC Distribution 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 Distribution 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 Distribution is committed to growing and expanding on the success of its existing community service and customer engagement initiatives.

PUC Distribution 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 included improving customer communications, increasing customer consultations, maintaining or improving reliability 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.

2.2.1.2 Municipal Government Consultations

Purpose of Consultation

PUC Distribution interacts with the City of Sault Ste. Marie administration to coordinate infrastructure planning within its service territory, so that new connections to customers can be connected in a timely manner and projects involving line relocates to facilitate road reconstruction projects can be planned. PUC Distribution staff attends formal meetings with the City and other municipal stakeholders and local utilities, annually, to review budgets and work plans for the coming year and the coming 5 years. Other 'ad hoc' coordination sessions occur on an 'as needed' basis with the city and development stakeholders to look for synergies on specific projects and initiatives such as subdivision, commercial and institutional developments

Who Initiated the Consultation and Other Participants?

The annual coordination meetings are generally initiated by the City's administration and PUC Distribution along with other utilities participating in them. For large developments in the city, PUC Distribution is invited to Development Assistance Review Team (DART) meetings on a regular basis early in the planning stage. Additionally, PUC Distribution is included and invited to comment on all rezoning, severance and building applications allowing PUC Distribution to identify requirements early in the development stage.

Other Participants in Consultations

Other participants include general service customers, developers, other utilities including gas and telecommunications.

Nature and Timing of Final Deliverables

The final deliverables from these consultations are in form of the development information such as plans and associated schedules, which are received during the meetings.

Consultations Impact on this DSP

The information obtained from the municipality has been used to identify investment level requirements in the System Access category, proposed in this DSP (subdivisions, joint use and general services).

2.2.1.3 Consultations with CDM Program Partners

Purpose of Consultation

The purpose of PUC Distribution's consultations with energy conservation and demand management (CDM) program partners is to implement the province of Ontario's policy on energy conservation and peak demand reduction on the electricity grid.

Who Initiated the Consultation and Other Participants?

PUC Distribution participates in periodic consultations initiated by IESO and also initiates consultations with its customers to promote and encourage energy conservation and identify and implement opportunities for demand management.

Nature and Timing of Final Deliverables

The final deliverables from these consultations are the leads for specific CDM opportunities, which are then pursued by PUC Distribution for implementation.

Brief Description of the Consultation

PUC Distribution has been offering IESO (formerly OPA) prescribed save-ON-energy CDM programs since 2011. As per the Minister of Energy's directive on Conservation and Demand Management dated March 31, 2014, PUC Distribution collaborated with CustomerFirst, a group of local distribution companies (LDCs) that have submitted a joint plan to the IESO under the new conservation framework.

PUC Distribution is committed to helping its customers understand their energy usage and reduce their environmental footprint 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 55% towards that target. This achievement was made possible through on-going consultations with customers, prompting a strong participation by PUC Distribution's commercial and industrial customers in retrofit and energy auditing programs. Residential customers also participated in sufficiently large numbers in saveONenergy coupon events opting to replace lights in their homes to more energy efficient ones, as well purchasing other energy efficient equipment. PUC Distribution's collaborative efforts with the residents and business owners within its service territory made the achievement of substantial energy savings possible. Notable projects include the conversion of the City's street lighting system from HPS to LED, not only in Sault Ste. Marie but also 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.

As a member of CustomerFirst, PUC Distribution 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 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 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. The CDM program has been effective in curtailing the rise in peak demand on the distribution system and this is one of the reasons why no investments are needed in the System Service category. In order to more effectively engage the residential customers into energy conservation programs, the effort will result in a slight increase in O&M expenditure from prior years' spending levels.

PUC Distribution actively participated in the saveONenergy CDM programs from 2011-2014, which were extended into 2015 to allow transition to a new 6-year framework. In complying with the Minister of Energy's directive on Conservation and Demand Management dated March 31, 2014, PUC Distribution collaborated with CustomerFirst, a group of LDCs, to submit a joint plan to the IESO to reduce peak demand under the new conservation first framework. As a member of the CustomerFirst LDCs, PUC Distribution continues to participate in evaluation of the conservation delivery, its impact of anticipated load growth as well as evaluation of the benefits of collaboration with LDCs in the partnership. Based on the results of customer consultations, a higher emphasis on residential conservation programs will be placed in the future, as the previous framework provided limited opportunities for energy conservation by the residential customer class.

Consultations Impact on this DSP

The consultations with CDM Program Partners have helped the peak demand on PUC Distribution's grid from increasing, and as a result the need for any associated investments has been avoided in this DSP.

2.2.1.4 IESO Consultations

Purpose of Consultation

The purpose of these consultations is to share information with IESO to facilitate and coordinate the connection of REG connections.

Who Initiated the Consultation and Other Participants?

The consultation was initiated by PUC Distribution in conjunction with preparation of this DSP. A renewable generation (REG) plan was prepared by PUC Distribution and submitted to IESO. IESO reviewed the REG plan and provided a comment letter.

Nature and Timing of Final Deliverables

PUC Distribution prepared and submitted the REG plan to IESO for review in November 2017. IESO provided a comment letter in December upon completion of its review, which is included in Appendix D.

Brief Description of the Consultation

PUC Distribution has been conducting communications in relation to the existing distributed generation connections connected to its network under OPA's RESOP, FIT and micro-FIT contracts as well as new applicants wishing to connect new renewable generation plant to PUC Distribution's network.

PUC Distribution has been a leader in actively promoting and facilitating Ontario's Green Energy program, which has resulted in the City of Sault Ste. Marie acquiring the title of the Alternative Energy Capital of North America. PUC Distribution has solar generation contribution of approximately 63MW connected to its distribution system, which results in near zero or net export conditions during their peak producing summer months when the distribution network is near its minimum load.

PUC Distribution has also worked closely with IESO in the integration of bulk energy storage on the grid. In April 2014, a private developer approached PUC Distribution to explore the possibility of connecting a 7MW/7MWh fast ramping energy storage facility to the provincial transmission system. The request was prompted by an IESO proposal call for such a project to be connected somewhere in the northeastern region. The facility was to be an experimental IESO venture to determine if bulk battery storage is an effective way to provide voltage stabilization and reactive power support in an environment with a relatively high ratio of renewable energy to traditional generation and a highly variable load/generation mix. PUC Distribution immediately recognized potential benefits for many stakeholders and developed terms of reference for a project to support connection at their St. Mary's transformer station TS1. The project proceeded successfully and the facility was put into operation in the fall of 2017.

To make the distribution grid more friendly to distributed generation and to provide customers greater access and control on their energy usage, PUC Distribution is also implementing affordable initiatives for smart grid development in a phased manner, to improve the stability and reliability of renewable generation connections and to meet customers' future needs. All of the customers have been equipped with smart meters. As the assets in existing distribution stations reach the end of their service life, during rebuilding of the distribution stations, modern automated switching and SCADA controlled devices are incorporated in the design.

Impact of the Consultation on this DSP

Because no constraints have been identified in PUC Distribution's grid preventing connection of renewable generation (REG) to the distribution grid, the consultations with IESO have not resulted in any investments proposed in this DSP to facilitate REG connections.

2.2.2 Regional Planning Process [5.2.2 b]:

Purpose of Consultation

The purpose of this consultation was to facilitate transmission system planning by identifying critical infrastructure needs of the transmission grid during the next 10 years from 2014 to 2023

Who Initiated the Consultation and Other Participants?

This consultation was initiated by the Hydro One Sault Ste. Marie LP (H1 SSM) (previously Great Lakes Power Transmission (GLPT), the lead transmitter. All electricity distributors in the region participated in the consultation as well as the IESO and OPA.

Nature and Timing of Final Deliverables

The final deliverable of this consultation was the Regional Infrastructure Planning Report, which is included in Appendix E.

Brief Description of the Consultation

PUC Distribution belongs to the "East Lake Superior Region (ELS-Region)", for which Hydro One Sault Ste. Marie LP (H1 SSM) (previously Great Lakes Power Transmission (GLPT) is the lead transmitter and primarily responsible for steering the regional planning in this region.

In response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013, regional infrastructure planning was triggered by H1 SSM on October 12, 2014 and was completed on December 12, 2014. PUC Distribution participated in the planning process and provided required data to H1 SSM. The scope of this planning initiative was to identify critical infrastructure needs of the transmission grid during the next 10 years from

2014 to 2023. The assessment included a review of transmission system connection facilities capacity which covers station loading, thermal and voltage analysis, system reliability, operational issues such as load restoration and asset sustainment plans. A copy of the Regional Infrastructure Planning report is attached in Appendix E.

The regional planning report concludes the existing transmission infrastructure in the region supplying the PUC Distribution's supply network has sufficient capacity and the circuit loading on all 115 kV circuits remain within the assessment criteria limits throughout the study period.

Impact of the Consultation on this DSP

Consultations with the transmitter did not lead to any impact on the capital investments proposed in this DSP.

2.2.3 IESO Comment Letter [5.2.2 c]

PUC Distribution's Renewable Energy Generation (REG) Plan outlining the plan to support connection of renewables and smart grid technologies for the period 2018-2022 was provided to IESO in December 2017. The plan indicates the PUC Distribution grid is presently very well positioned to support all forecast REG connections over the next five years and no associated infrastructure investment is required during that period. The IESO acknowledged that PUC Distribution's system shows no concerns caused by local or regional issues that should constrain additional growth of REG as projected. The plan and response letter are attached in Appendix D.

2.3 Performance Measurement for Continuous Improvement [5.2.3 a to c; 5.4.3a]

In order to continually improve its operating performance, PUC Distribution continually measures and monitors its performance. The performance indicators employed by PUC Distribution in measuring its operating performance have evolved over the years and these are currently fully aligned with OEB's "Scorecard – Performance Measures" for electricity distributors, as listed below:

1) service quality;
2) customer satisfaction;
3) safety;
4) system reliability;
5) asset management;

6) cost control;

7) financial ratios;

8) conservation and demand management; and

9) connection of renewable generation.

For each of the performance indicators listed above, PUC Distribution has adopted the standard measurement metrics, used by OEB in its "Scorecard – Performance Measures". For definitions of the performance measures, please refer to Appendix F. The OEBs first year requiring LDCs to submit scorecards was for 2013 with the corresponding Management Discussion & Analysis introduced in 2014. Accordingly, only scorecards for 2013 and forward have been included.

PUC Distribution's operating performance during five years from 2012 to 2016, as reported in the 2016 Scorecard, is summarized in the following sections:

2.3.1 Service Quality

PUC Distribution measures and monitors service quality to ensure continued improvement, to achieve a level satisfactory to its customers and in accordance with its core value of being responsive to customer needs. OEB's directive to measure and report on service quality is the motivation for service quality measurements. PUC Distribution has aligned its service quality indicators and their measurement metrics with those mandated by OEB.

PUC Distribution monitors its service quality by measuring the following service quality indicators: (a) new residential services connected on time, (b) scheduled appointments met on time, and (c) telephone calls answered on time. The key purpose for tracking this metric is to determine how well PUC Distribution is able to meet its customers' requests for service in a timely manner. As indicated in Table 3, PUC Distribution's has met the performance target for each performance metric during each of the past five years.

Table 3: Service Quality Performance

Service Quality Metric	Target	Actual				
		2012	2013	2014	2015	2016
New LV Connections (<700 V) on time	90.0%	95.8%	96.5%	93.0%	97.2%	98.9%
Meeting Scheduled Appointments on time	90.0%	98.4%	97.1%	95.4%	97.4%	98.3%
Telephone accessibility (Answering calls within 30 seconds)	65.0%	74.6%	80.9%	81.9%	82.3%	81.3%

As a minimum performance standard for the connection of new services, new low-voltage (< 750 volts) services must be connected within 5 working days from the day on which all conditions of service are satisfied, including electrical safety inspection.

As a minimum standard, when it is necessary to meet a customer at the customer's premises or work site to conduct utility business, customers must be offered a choice of morning or afternoon appointments. The appointments must be met at least 90% of the time. If the appointed time cannot be met the customer must be notified.

As a minimum standard, incoming calls to the general inquiry telephone number must be answered within 30 seconds, at least 65% of the time.

No new investments are proposed in this DSP in response to PUC Distribution's performance on this metric.

2.3.2 Customer Satisfaction

PUC Distribution measures and monitors its customer satisfaction level to ensure customer needs are clearly understood and responded to. OEB's directive to report on customer satisfaction levels is the motivation for customer satisfaction monitoring and reporting. PUC Distribution has aligned its customer satisfaction indicators and their measurement metrics with its core value of being responsive to customer needs and with those of the OEB.

Three different OEB defined metrics are employed for customer satisfaction measurement: first contact resolution, billing accuracy and customer satisfaction surveys. The first two performance indicators were introduced by OEB in 2014 and the third performance indicator - "customer satisfaction surveys" was introduced in 2015. The key purpose for tracking First Contact Resolution is to determine how effectively customers' concerns are resolved by PUC Distribution. The key purpose for tracking Billing accuracy is to monitor PUC Distribution's performance in preparing and presenting the electricity bills to its customers accurately. PUC Distribution's performance during the past three years is indicated in Table 4 and as shown PUC Distribution's performance exceeds the defined targets.

Table 4: Customer Satisfaction Performance

Service Quality Metric	Target	Actual				
		2012	2013	2014	2015	2016
First Contact Resolution	N/A	N/A	N/A	99.89%	99.92%	99.58%
Billing Accuracy	98%	N/A	N/A	99.83%	99.36%	99.97%
Customer Satisfaction Suvey	N/A	N/A	N/A	N/A	79%	80%

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.

Accurate bills issued expressed as a percentage of total bills issued. It is calculated as: = (Total number of bills issued for the year – Number of inaccurate bills issued for the year) / Total number of bills issued for the year. This requirement must be met at least 98% of the time on a yearly basis.

PUC Distribution engaged a consultant to conduct our customer satisfaction surveys.

No new investments are proposed in this DSP in direct response to PUC Distribution's performance on this metric.

2.3.3 Safety

PUC Distribution measures and monitors safety related to its infrastructure and operations with the objective of minimizing the risk of accidents and injuries. OEB's directive to report on safety indicators is the motivation for monitoring safety performance. PUC Distribution has aligned its safety performance indicators and their measurement metrics with those mandated by OEB and consistent with its own core values.

Three different safety performance indicators are in use: level of public safety awareness, compliance with Ontario Regulation 22/04 and serious electrical incident index.

Table 5 summarises PUC Distribution's safety performance over the past five years, based on compliance with Regulation 22/04 and serious electrical incident index. The third measurement metric for this performance indicator – "level of public awareness of electrical safety" was introduced in 2015 and performance levels for this metric are not available for years prior to 2015. The purpose for tracking Level of Compliance with Reg. 22/04 is to monitor PUC Distribution's performance in complying with Ontario Regulation 22/04, which specifies the safety requirements to be met by Electricity Distributors in Ontario. The purpose of tracking Incident Index is to benchmark PUC Distribution's performance in operating its distribution lines safely; the metric monitors normalized number of incidents involving safety violations.

To improve public safety of power distribution systems, Regulation 22/04 was introduced in the province of Ontario in 2005. Since that time PUC Distribution has participated, as required, in an annual audit to assess compliance with the regulation. The auditor provides an assessment of compliance using one of the four designations: i) C – complies, ii) NI – Needs Improvement iii) NC – Non-compliance, iv) N/A – not applicable. As shown in Table 5, PUC Distribution has been found to be compliant with Regulation 22/04 in each of the past four years.

The 2016 results pertaining to the Serious Electrical Incident Index show a marked improvement from previous years in each of the (a) number of general public incidents and (b) rate per 10, 100, 1000km of line.

Table 5: Safety Performance

Safety Performance Indicator		2012	2013	2014	2015	2016
Level of Public Awareness		N/A	N/A	N/A	86%	86%
Level of Compliance with Ontario Regulation 22/04		NI	C	C	C	C
Serious Electrical Incident Index	Number of General Public Incidents	3	1	3	1	0
	Rate per 10,100,1000 km of line	0.407	0.135	0.405	0.134	0.000

To improve the level of public awareness about electrical safety, PUC Distribution employs a number of programs, including periodic electrical safety discussions at schools and relaying electrical safety messages to public through radio and print media. To maintain compliance with Regulation 22/04, strict project management procedures are followed; ensuring distribution systems are designed and constructed following approved engineering standards, meeting all applicable codes. All distribution system infrastructure is systematically inspected and tested when required and plans for repair or renewal of assets presenting safety risks are prepared and implemented.

Infrastructure assets found in poor and very poor condition present a high risk of failure in service. Maintaining public safety and ensuring PUC Distribution continues to meet its obligation to comply with the safety regulations is a driver for many of the projects included in the System Renewal category. For example, the following material projects, summarized in Table 22 to be implemented during the test year are intended to improve both safety and reliability performance:

Projects #5, #6, #7, #8, #9, #10, #11, #12 and #13.

2.3.4 System Reliability

PUC Distribution measures and monitors the reliability of power supply to its customers with the objective of maintaining reliability levels meeting its customers' needs. OEB's directive to report on supply system reliability is the motivation for monitoring supply system reliability. PUC Distribution has aligned its reliability performance indicators and their measurement metrics with those prescribed by the OEB. Currently, two reliability performance indicators are tracked on the OEB score card: System Average Interruption Frequency Index (SAIFI) and

System Average Interruption Duration Index (SAIDI). PUC Distribution's targets and actual performance in terms of SAIDI and SAIFI are summarized in Table 6. The table indicates reliability performance under three scenarios:

(a) By including all power interruptions

(b) By excluding interruptions due to loss of supply (OEB was monitoring reliability performance in this format from 2013 to 2015), and

(c) By excluding interruptions due to loss of supply and major climatic events (OEB started monitoring reliability in this format in 2016).

"Major Events" are defined by OEB as the events beyond the control of the distributor and are uunforeseeable, unpredictable; unpreventable; or unavoidable. Such events disrupt normal business operation 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, they take significantly longer than usual to repair, and they affect a substantial number of customers.

The OEB has established targets for SAIFI and SAIDI, against which actual performance is measured by PUC Distribution. There are no established targets for CAIDI. Targets and results are illustrated in Table 6. The following serves to identify the methodology used by the OEB to establish the annual targets for SAIFI and SAIDI:

- For 2012 there were no established targets for SAIDI and SAIFI
- For the years 2013 and 2014: targets were set to achieve the range of the actual minimum and maximum values over the 2009 to 2012 timeframe, by excluding interruptions due to loss of supply; results were within or better than the prescribed limits;
- For 2015: targets were set based on the fixed 5-year average from 2010 to 2014, by excluding interruptions due to loss of supply; SAIFI was below the target and SAIDI was above; and
- For 2016: targets were set based on the fixed 5-year average from 2010 to 2014, by excluding interruptions due to loss of supply and major events; results were better than the targets.

Table 6: Reliability Performance

(a) With all power interruptions Included

	2012	2013	2014	2015	2016
SAIDI Target	N.A.	N.A.	N.A.	N.A.	N.A.
SAIDI Actual	1.65	2.65	1.19	3.35	2.53
SAIFI Target	N.A.	N.A.	N.A.	N.A.	N.A.
SAIFI Actual	2.17	3.53	1.21	1.84	2.21
CAIDI Target	N.A.	N.A.	N.A.	N.A.	N.A.
CAIDI Actual	0.76	0.75	0.98	1.82	1.14

(b) With Interruptions due to loss of supply excluded

	2012	2013	2014	2015	2016
SAIDI Target	N.A.	1.65-2.92	1.65-2.92	2.07	N.A
SAIDI Actual	1.65	2.48	1.19	3.35	2.46
SAIFI Target	N.A.	2.17-3.61	2.17-3.61	2.50	N.A.
SAIFI Actual	2.17	2.67	1.21	1.84	2.11
CAIDI Target	N.A.	N.A.	N.A.	N.A.	N.A.
CAIDI Actual	0.76	0.93	0.98	1.82	1.17

(c) With interruptions due to loss of supply and major events excluded

	2012	2013	2014	2015	2016
SAIDI Target	N.A.	N.A.	N.A.	N.A.	1.86
SAIDI Actual	1.65	1.42	1.19	1.37	1.49
SAIFI Target	N.A.	N.A.	N.A.	N.A.	2.32
SAIFI Actual	2.17	1.78	1.21	1.03	1.41
CAIDI Target	N.A.	N.A.	N.A.	N.A.	N.A.
CAIDI Actual	0.76	0.80	0.98	1.33	1.06

- SAIDI = (Total Customer Hours of Interruptions – Total Customer Hours of Interruptions caused by Loss of Supply events)/ Average Number of Customers Served.

- SAIFI= (Total Customer Interruptions – Interruptions caused by Loss of Supply events) / Average Number of Customers Served

- CAIDI = SAIFI/SAIDI

As shown in Table 6, there is significant year over year variation in SAIDI and SAIFI performance over the past five years. Equipment failures in service have been the predominant cause of outages on PUC Distribution's supply network during the past several years. All of the investments included under System Renewal category, are aimed at replacing assets in very poor and poor condition, with priority given to renewal of those assets that present the highest risk of failure in service with most serious consequences. For example Table 22 shows the prioritized list of the material projects to be implemented during the test year. From that table, the following projects are intended to keep supply system reliability from degrading below the acceptable range:

Project #5, #6, #7, #8, #9, #10, #11, #12, and #13.

Out of a total of 13 material projects planned to be implemented during the test year, nine are aimed at preventing reliability from deteriorating through replacement of assets, determined to be at the end of their useful service life. Considering the large impact of substation equipment and feeder trunk line failures on reliability, the risk of a prolonged power outage will remain on the horizon until renewal of all assets determined to be in poor or very condition has been completed.

2.3.5 Asset Management

PUC Distribution monitors the effectiveness of its asset management practices to ensure planned projects related to infrastructure renewal, refurbishment and maintenance aimed at preventing asset impairment in service and to reduce the risk of asset failures in service, are implemented as planned on a timely basis. PUC Distribution's corporate strategy to achieve success requires the sustainability of assets and systems. The corresponding 2018 objectives include the achievement of budgeted capital programs and is the motivation for monitoring this performance indicator. Furthermore, good asset management practices align with PUC Distribution's core value of being responsive to customer's needs including service delivery and system reliability.

To measure the effectiveness of its asset management program, PUC Distribution measures the system plan implementation progress by comparing work accomplishment to plan as well as the actual capital and operating expenditure against the budget, analyzing the reasons for variance and taking corrective action, when required.

Table 7 shows the program level variance in PUC Distribution's actual expenditure from its planned expenditure during the past five years. All amounts shown are net of contributed capital from customers.

Although no historical expenditures are indicated in the System Service category, a number of investments are grouped in the renewal category which is considered the primary driver. More specifically this includes station rebuilds, voltage regulation, reclosers, line rebuilds, SCADA improvements and protection upgrades. These upgrades introduced smart grid features, including opportunities for greater automation, improved access for connection of renewable generation and improved access for joint-use of distribution facilities. Therefore, these investments can be considered to serve multiple roles: System Access and System Service in addition to System Renewal which was the primary driver.

Table 7: Program Level Variance – Budget Vs Actual Spending

	2012			2013			2014		
	Budget	Actual	Variance	Budget	Actual	Variance	Budget	Actual	Variance
System Access	1,132,235	7,938,036	6,805,801	1,068,766	2,310,000	1,241,234	2,957,353	2,531,753	(425,600)
System Renewal	6,042,853	4,821,060	(1,221,793)	6,525,051	6,082,921	(442,130)	3,813,022	3,753,603	(59,419)
System Service	-	-	-	-	-	-	-	-	-
General Plant	17,802,500	23,269,373	5,466,873	1,313,518	2,028,344	714,826	175,445	375,693	200,248
Total Capital Expenditure	24,977,588	36,028,469	11,050,881	8,907,335	10,421,265	1,513,930	6,945,820	6,661,049	(284,771)
System O&M Expenditure	6,259,122	5,852,889	(406,233)	6,153,732	5,992,120	(161,612)	5,529,970	5,773,408	243,438

	2015			2016		
	Budget	Actual	Variance	Budget	Actual	Variance
System Access	1,265,490	1,549,411	283,921	1,214,680	1,211,917	(2,763)
System Renewal	4,752,934	4,639,948	(112,986)	4,542,992	4,243,808	(299,184)
System Service	-	-	-	-	-	-
General Plant	68,653	66,532	(2,121)	0	82,630	82,630
Total Capital Expenditure	6,087,077	6,255,891	168,814	5,757,672	5,538,355	(219,317)
System O&M Expenditure	5,819,316	5,977,598	158,282	5,955,321	5,977,871	22,550

2.3.5.1 Variance Analysis - Capital Expenditure

Capital Expenditure Variations in 2012

Table 7 indicates that in 2012, the actual expenditure in the "System Access" category exceeded the budget by over $6.8 million. This variation is related to the smart metering project – Although the installation work was physically substantially complete at the end of 2010, the costs were not capitalized until 2012.

The actual expenditure in "General Plant" category exceeded the budget by over $5.5 million. This variation in expenditure is related to the construction of the new office building, which was budgeted in 2011, but most of the work on it was completed in 2012.

The variation of ($1.2 million) in the "System Renewal" category was primarily due to delays experienced during the reconstruction of the 12kV substation Sub 10. Engineering resource constraints, equipment deliveries and poor winter weather were primary contributors to pushing completion of this project out into 2013.

Capital Expenditure Variations in 2013

Table 7 indicates that in 2013, the actual expenditure in the System Access category exceeded the budget by over $1.2 million. This variance was primarily a result of the utility having to support a substantially large and unplanned for joint-use project for one of the major telecommunications companies sharing space on its overhead infrastructure. A significant volume of make-ready work was completed to allow them to attach their fiber optic cables on PUC Distribution overhead poles. The scale of the project also led to resource constraints so that some projects in the System Renewal were not completed.

The actual expenditure in General Plant category exceeded the budget by approximately $720,000. This variation in expenditure was solely related to the construction of the new office building referred to above in 2012 for which a number of small remaining outstanding items and deficiencies were not completed until early 2013.

In the System Renewal category actual expenditure was less than the budget by approximately $440,000. This was primarily attributable to resource constraints experienced due to the joint use fibre project discussed in the System Access category above.

Capital Expenditure Variations in 2014

In 2014, the variation in overall capital expenditure from the budget was insignificantly small – less than 4% of the budget.

The actual expenditure in the System Access category was less than the budgeted amount by about 14%. This was attributable to a combination of two factors. Firstly, continuation of the large joint-use fibre project (that was mentioned in the section above) started in 2013 was budgeted for in 2014. However, as the project progressed, circumstances changed for the telecommunications company and they canceled the project at approximately the half-way point. This had the effect of being significantly underspent on associated make-ready work. The second lesser impacting, but mitigating factor was higher than anticipated customer demand and the addition of City reconstruction projects that required additional infrastructure relocation.

In the System Renewal category, the actual expenditure was less than the budget by 2%.

The actual expenditure in General Plant category exceeded the budget by approximately $200,000. This variation in expenditure is related to the purchase and installation of furnishings, fit-ups and equipment (FF&E) for the newly constructed office building that were not anticipated at the time of budgeting the project.

Capital Expenditure Variations in 2015

In 2015, the overall capital expenditure exceeded the budget by approximately 3% and this variation was caused primarily by an overrun of $285,000 in the System Access category. PUC Distribution was required to relocate lines to facilitate municipal projects for which information was not available in advance of preparing the 2015 budget.

Capital Expenditure Variations in 2016

In 2016, the variation in overall capital expenditure from the budget was small – less than 4% of the budget.

In the System Renewal category, the actual expenditure was less than the budget amount by about 7%, primarily due to equipment failures, leaking transformers and deteriorated poles.

2.3.5.2 Variance Analysis for O&M Expenditure

As shown in Figure 2, the variations in annual O&M expenditure from the budget are rather modest, ranging from -6.5% to +4%. During 2012 and 2013, due to the unexpected increase in the System Access category of capital projects consuming the limited resources of PUC Distribution, some of the maintenance activities planned for 2012 and 2013 were deferred to 2014 and 2015, which resulted in the variance.

There is an overall 2.1% increase in actual O&M expenditures from $5.85 million to $5.98 million over the 2012-2016 period.

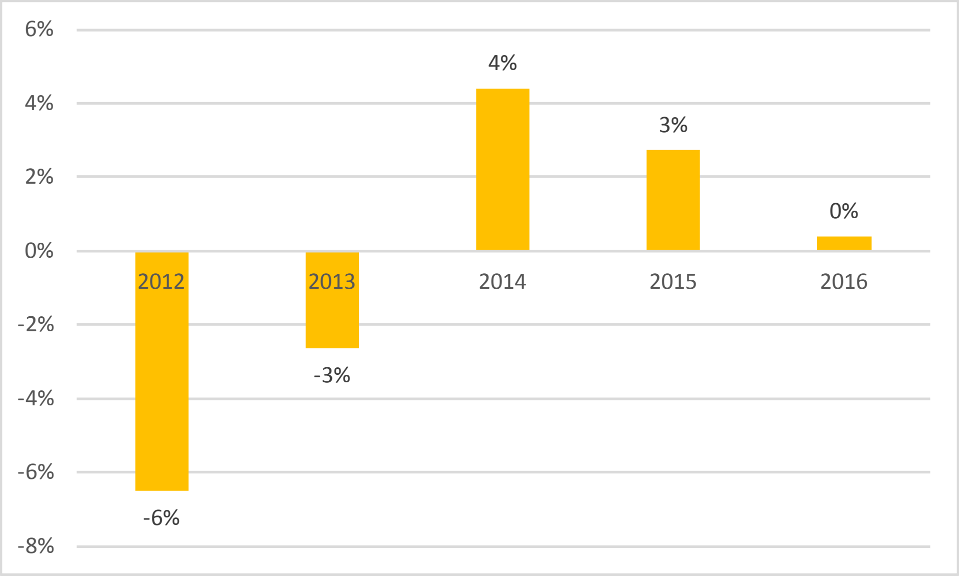


Figure 2: Variation in Actual O&M Expenditure from Budget

2.3.5.3 Initiatives to Reduce Project Variance in Future

Due to variability and uncertainty in the number of requests received for unplanned work under the System Access category, variance in actual expenditure from the planned amount cannot be eliminated. PUC Distribution intends to reduce such variances, through improved resource planning and project management.

A proactive project management approach was implemented between 2014 and 2016, to ensure continuous improvement in resource planning and project management on capital projects. Project and budget status meeting are held frequently throughout the year. Annual reviews are performed to identify reasons for variance and long-term corrective action is taken through implementation of or modification to existing processes and designs.

A review of the capital spending from 2014 to 2016 confirms that the recently implemented proactive project management initiative is yielding intended results with overall variances between -4% and +3%.

There are no capital investments proposed in this DSP related to PUC Distribution's performance on this performance measure.

2.3.6 Cost Control

PUC Distribution measures and monitors the cost efficiency for distributing electricity and serving customers within its service territory, with the purpose of benchmarking its recent performance and remaining economically efficient in the future. OEB's directive to measure and report on cost efficiencies as well as PUC Distribution's own vision and mission statements are the motivation for cost controls. PUC Distribution has aligned its cost control indicators and their measurement metrics with those prescribed by OEB.

PUC Distribution measures and reports on the following cost efficiency indicators, including its cost efficiency ranking among peers, total cost per customer and total cost per km of line; which are discussed here as follows:

2.3.6.1 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 8 summarizes the OEB rankings of the local electricity distributors based on cost efficiency in 2016:

Table 8: LDC Rankings Based on Cost Efficiency

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 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. Projections for 2017 indicate that PUC Distribution would still be in Group 4 after removing the non-operating type costs from the PEG calculation. However, PUC Distribution's efficiency ranking improves to 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.

2.3.6.2 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. Figure 3 shows PUC Distribution performance during the past five years, based on total OM&A cost per customer.

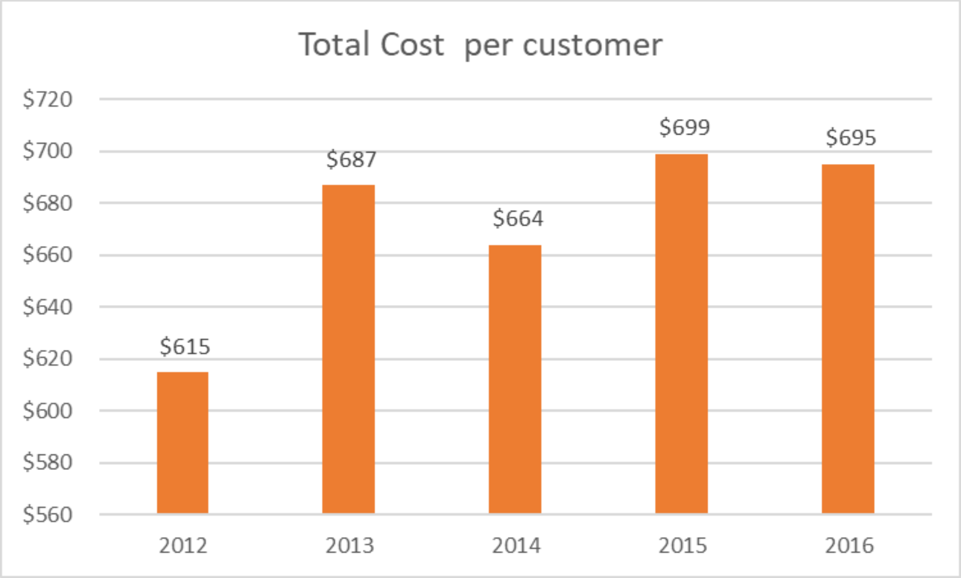


Figure 3: Operating Efficiency Performance (Total Cost per Customer)

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 0.40% per year. The cost performance result for 2016 is $695 per customer which is a 0.57 % decrease over 2015.

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 $664 excluding the non-operating costs discussed above.

2.3.6.3 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. Figure 4 shows PUC Distribution's performance based on total Capital and OM&A cost per km and cost per customer.

Figure 4: Operating Efficiency Performance (Total Cost per km)

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. PUC Distribution's total cost per km in 2016 was $31,314, which represents a 0.20% decrease over 2015. PUC Distribution's target for this metric in 2018 is $30,274 excluding the non-operating costs discussed above.

2.3.7 Financial Ratios

PUC Distribution measures and monitors the financial ratios for the business corporation, to ensure financial stability and economic efficiency to sustain its corporate operations in a responsible manner, providing services required by its customers in an effective and cost-efficient manner and providing a reasonable return on equity to its shareholders.

Monitoring and tracking these metrics both meets the OEB's directives pertaining to financial ratios and aligns with PUC Distribution Inc.'s own vision and mission statements.

PUC Distribution's financial ratios during the past five years are summarized in Figure 5 through Figure 7.

2.3.7.1 Liquidity: Current Ratio (Current Assets/Current Liabilities)

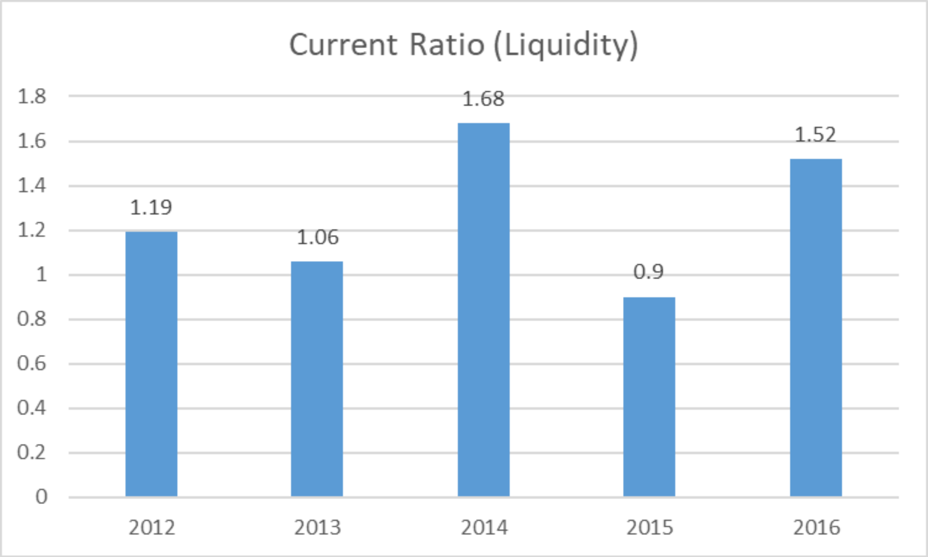


Figure 5: Current Ratio

As an indicator of financial health, a current ratio that is greater than 1 is considered good as it indicates that the company can pay its short-term debts and financial obligations. Companies with a ratio of greater than 1 are often referred to as being “liquid”. The higher the number, the more “liquid” and the larger the margin of safety to cover the company’s short-term debts and financial obligations. 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.

2.3.7.2 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.

Figure 6 shows the overall debt/equity ratio and over the past five years PUC Distribution has maintained an average debt/equity ratio of 2.21. The following factors have contributed towards an increase in debt/equity ratio during the past five years:

- Reduced Return on Equity, since the last Cost of Service rate application in 2013, which has resulted in a lower equity position than anticipated.
- Loans from Infrastructure Ontario in 2013 (~$21 million) and 2015 ($15 million) have substantially increased PUC Distribution's long-term debt.
- PUC Distribution has a $26.5 million Note Payable to its parent (City of Sault Ste. Marie).

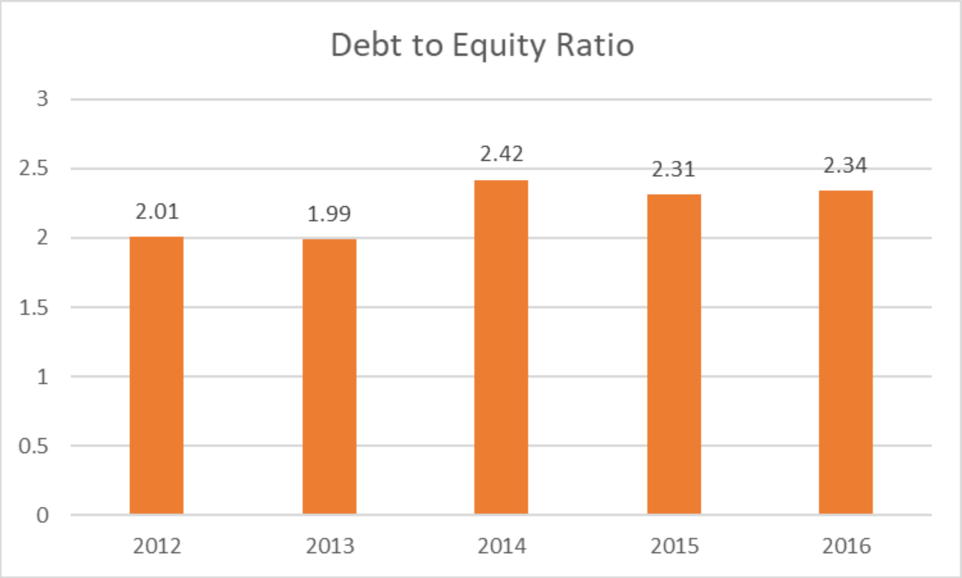


Figure 6: Total Debt to Equity Ratio

2.3.7.3 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.

2.3.7.4 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 Distribution's OM&A request for the 2013 Cost of Service rate application was $10.93; however this amount was reduced through the settlement process to the approved amount of $9.95. Although PUC Distribution 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 Distribution's expenditures in 2013 were $11.16 million compared to the approved amount in rates of $9.95 million. The increase of $1.21 million from 2012 to 2013 is detailed below in Table 9:

Table 9 - Incremental OM&A from 2012 to 2013

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, 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 customer's bills – number of write-offs 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	
	$1,210,000	

Subsequent to the increase in 2013, OM&A expenses have increased marginally from $11.16 million in 2013 to $11.36 million in 2016. This equates to a three year average annual increase of 0.6%.

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.

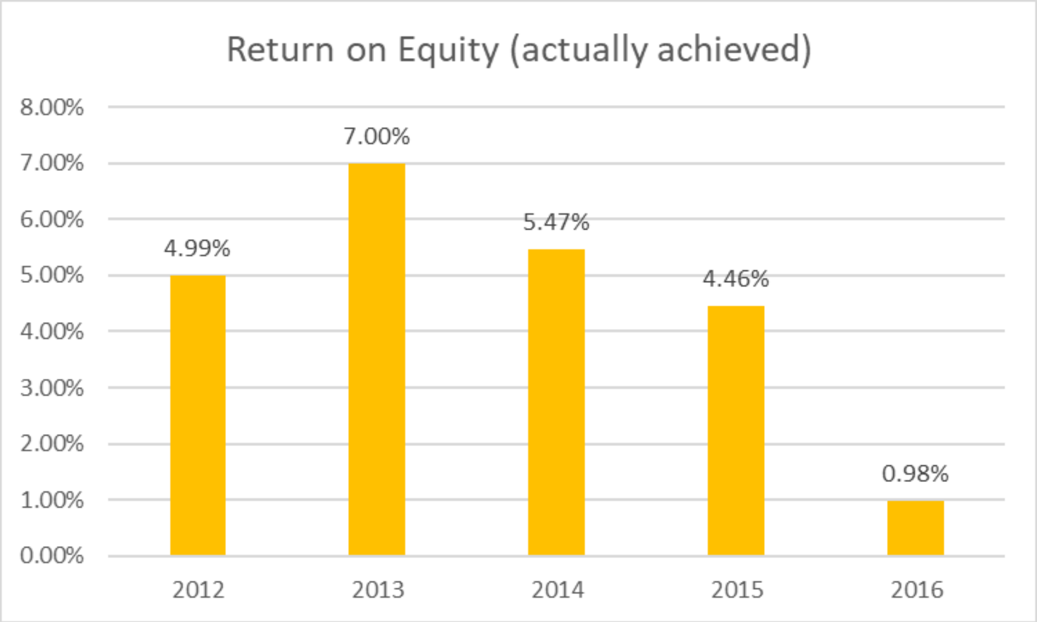


Figure 7: Regulatory Return on Equity

2.3.8 Conservation and Demand Management (CDM)

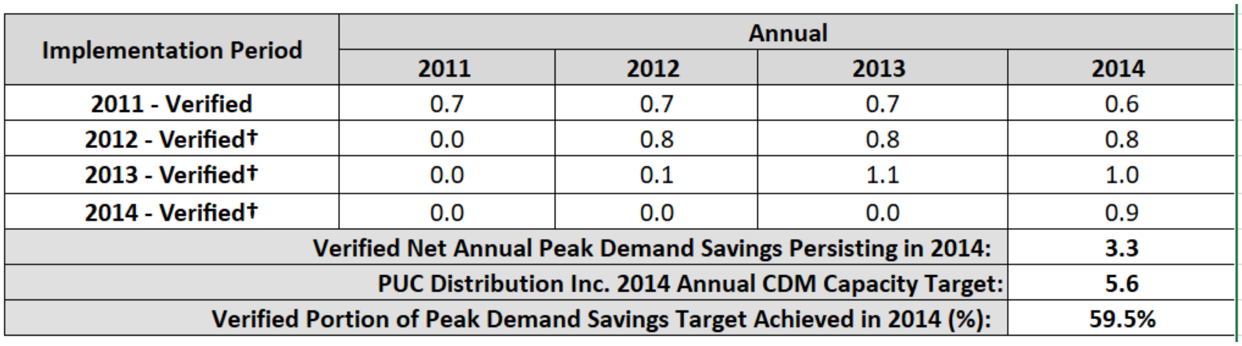
PUC Distribution measures and monitors its progress in implementing CDM program to ensure continued progress in meeting the assigned targets for its service territory for energy conservation and demand reduction. OPA/IESO's policy and guidelines and OEB's directive to comply with these policies and guidelines is the motivation for monitoring and reporting on the progress in meeting CDM targets. PUC Distribution reports on the CDM progress using IESO/OPA approved report formats. Furthermore, CDM initiatives are aligned with PUC Distributions core values of innovation and responsiveness. In conjunction with the CustomerFirst collaborative innovative approaches are implemented for the delivery of CDM programs to customers. This multi-utility approach also serves to ensure that collaborative programs are responsive to customer needs.

PUC Distribution has been actively participating in the province's energy conservation and demand management (CDM) programs, engaging all customer groups within its service territory. CDM continues to play a critical role in helping customers manage their electricity costs, while making a positive contribution in de-accelerating the rate of global warming and reducing the peak demand on the distribution grid. PUC Distribution participates in a number of IESO's incentive programs designed to reduce energy use and to promote effective environmental conservation. The current Save on Energy conservation framework has started to gain considerable momentum in PUC Distribution's service territory and a number of CDM programs have been successfully implemented.

Table 10 and Table 11, respectively, show the savings in peak demand and energy use, achieved during the first tranche of the program, from 2011 to 2014. CDM targets were redefined in 2015. Table 12 shows the performance achieved in relation to the new 2020 target for energy savings.

As indicated in those tables, PUC Distribution's proactive engagement in energy conservation and demand management programs has contributed significantly to province's CDM targets and more specifically in curtailing the peak demand on its distribution grid. The reduction in demand has resulted in no investment requirements to address any capacity constraints on the distribution network.

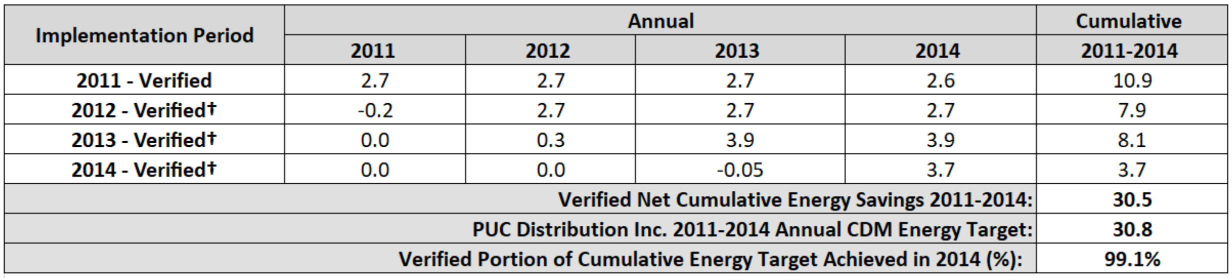
Table 10: PUC Distribution’s Net Peak Demand Savings at End User Level 2011-14 (MW)



Implementation Period	Annual			
	2011	2012	2013	2014
2011 - Verified	0.7	0.7	0.7	0.6
2012 - Verified†	0.0	0.8	0.8	0.8
2013 - Verified†	0.0	0.1	1.1	1.0
2014 - Verified†	0.0	0.0	0.0	0.9
Verified Net Annual Peak Demand Savings Persisting in 2014:				**3.3**
PUC Distribution Inc. 2014 Annual CDM Capacity Target:				**5.6**
Verified Portion of Peak Demand Savings Target Achieved in 2014 (%):				**59.5%**

†Includes adjustments to previous years' verified results

Table 11: PUC Distribution’s Net Energy Savings at End User Level 2011 – 14 (GWh)



Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	2.7	2.7	2.7	2.6	10.9
2012 - Verified†	-0.2	2.7	2.7	2.7	7.9
2013 - Verified†	0.0	0.3	3.9	3.9	8.1
2014 - Verified†	0.0	0.0	-0.05	3.7	3.7
Verified Net Cumulative Energy Savings 2011-2014:					**30.5**
PUC Distribution Inc. 2011-2014 Annual CDM Energy Target:					**30.8**
Verified Portion of Cumulative Energy Target Achieved in 2014 (%):					**99.1%**

†Includes adjustments to previous years' verified results

Table 12: PUC Distribution’s Net Incremental Energy Savings 2015-2020 (kWh)

Year	Residential kWh	Non-Residential kWh	Local LDC Programs	LDC Innovation Pilots	IESO Verified Total (kWh)	OEB Target (kWh to 2020)	% of 2020 Target Achieved (Cumulative)
2015	1,969,397	3,431,349	0	0	5,400,746	26,410,000.00	20%
2016	3,822,336	5,307,038	0	270	9,129,644		55%

2.3.9 Renewable Generation (REG) Connections

PUC Distribution measures and monitors its progress in facilitating and implementing the renewable generation connections requested by customers in its service territory. OEB’s directives follow the province’s broader policy to encourage and facilitate REG connections and are the motivation for monitoring this performance indicator. PUC Distribution measures its operating performance for REG connections by confirming if the REG connection requests are processed within the time period specified by OEB as indicated in Table 13. Customers realize benefits associated with REG connections in the form of cost savings which is consistent with PUC Distributions strategic goal of delivering improved customer satisfaction.

Table 13: PUC Distribution's REG Connection Performance

	2012	2013	2014	2015	2016	Target
REG Connection Impact Assessments completed on Time	-	-	-	0%	100%	-
New Micro-Embedded Generation Facilities Connected on Time	-	100%	100%	100%	-	90%

PUC Distribution has proactively participated in Ontario's Green Energy program, by facilitating the connection of Renewable Energy Generation (REG) to the distribution grid. PUC Distribution currently has approximately 63MW of REG connected to its distribution system, which on occasion results in net export conditions during summer months when the distribution network is near its minimum load.

Section 25.37 of the Electricity Act, 1998 requires that connection assessments for renewable energy generation facilities be completed by electricity distributors within prescribed timelines, and it also requires distributors to report quarterly to the Board on their ability to meet those timelines. Ontario Regulation 326/09 (Mandatory Information re Connections) sets out details regarding the timing of, and reporting on, connection assessments. Electricity distributors are required to conduct Connection Impact Assessments (CIAs) within 60 days of receiving authorization for their project from the Electrical Safety Authority. All requests received in 2016 for connecting REG connections under province's FIT program have been successfully connected by PUC Distribution.

For generation facilities that are 10 kW or less, the OEB established a connection measure in amendments to the Distribution System Code that came into effect on June 13, 2013 (EB-2012-0246). A distributor shall connect an applicant's micro-embedded generation facility to its distribution system within 5 business days of which all applicable service conditions are satisfied, 90 percent of the time on a yearly basis, or at such later date as agreed to by the customer.

100% of the requests received to date for micro-FIT (<10kW) generation facilities have been successfully connected within the OEB mandated time period. No REG connection requests have been turned down due to capacity constraints.

3 Asset Management Process [5.3]

This section describes in detail PUC Distribution’s asset management process and the direct links between the asset management process and the expenditure decisions that comprise the capital investment plan covered by this DSP.

3.1 Asset Management Process Overview [5.3.1]

3.1.1 Corporate Goals, Asset Management Objectives, and Investment Prioritization [5.3.1a]

In developing and implementing the asset management plan, PUC Distribution has aligned its key objectives with its corporate vision, mission and core values. PUC Distribution’s vision is to be recognized as a progressive electric distribution company committed to delivering value, innovation, prosperity and excellence. PUC Distribution’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. Its core values are:

- **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 Distribution 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

- **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 its mission, vision and core values, PUC Distribution has established the focus areas, corporate strategic goals and strategies to achieve the goals identified in Table 14:

Table 14: PUC Distribution's Focus Areas, Goals & Strategies

Focus Area	**Strategic Goals**	**Strategy to Achieve Goal**
Customers	Achieve A+ customer satisfaction Rating Meet or exceed all score card targets	Improve customer focus, customer satisfaction, communication, engagement and education Improve service quality
Employees	Be recognized as one of Canada's top 100 employers Organization Safety Excellence	Implement P3S0 organizational transformation - proactive employee engagement and training Continuous improvement of safety culture and performance
Shareholder	Achieve OEB deemed return on equity Increase value of company	Ensure sustainability of assets and system Productivity/business process improvements Explore permitted business opportunities

To achieve these strategic goals the key objectives on which the asset management plan is based have been ranked on a scale of 1 to 5. For further clarity, objectives ranked as a 1 have been classified as having the lowest priority for investment while those given a ranking of 5 are classified as having the highest priority. The ranking is meant to score the objectives on a relative basis. The following tactical objectives are intended to support and align with the broader strategic goals referenced above:

- ✓ Ensuring investment plans are aligned with the corporate goals - Ranking 5
- ✓ Ensuring investment plans are cost effective - Ranking 5
- ✓ Ensuring investment plans provides value to the customers - Ranking 5
- ✓ Ensuring investment plans are responsive to public policy - Ranking 5

✓ Maintaining public and employee safety - Ranking 5

✓ Maintaining reliability commensurate with customer needs - Ranking 5

✓ Providing customer service quality to satisfy customer needs - Ranking 5

✓ Maintain safe and ergonomic work place, tools and equipment - Ranking 5

✓ Controlling costs - minimizing asset life cycle costs - Ranking 4

✓ Minimizing risk of in-service failures - Ranking 4

✓ Minimizing environmental risks, - Ranking 4

✓ Aligning the DSP with regional planning objectives - Ranking 3

✓ Facilitating new renewable generation connections; - Ranking 3

✓ Facilitating the smart grid development - Ranking 2

Because there are no pending applications for connecting renewable generation, a lower ranking for investments into smart grid development and facilitating renewable generation connections has no significant adverse impact. Similarly, none of the investments proposed in this DSP conflict with the regional planning objectives and therefore lower ranking of the regional planning objectives has no adverse impact.

3.1.2 Asset Management Process Components [5.3.1 b]

3.1.2.1 Asset Management Strategy

Decisions involving investment into fixed assets play a major role in determining the optimal performance of distribution system fixed assets. Investments that are either oversized or made too far in advance of the actual system need may result in non-optimal operation. On the other hand, investment not made on time when warranted by the system needs raise the risk of performance targets not being achieved and would also result in non-optimal operation. Optimal operation of the distribution system is achieved when “right sized” investments are planned and implemented into new assets involving system extension or capacity upgrades or renewal, rehabilitation, repair or preventative maintenance of existing assets, based on a “just-in-time” approach. In summary, the overarching objective of the Asset Management Strategy is to find the right balance between capital investments in new infrastructure and operating and maintenance costs so that the combined total cost over the life of the asset is minimized, while fully addressing customer service quality and needs.

3.1.2.2 Investment Prioritization Process

As described previously in Section 1, Capital investments into infrastructure assets are classified into four categories, as defined in OEB's Chapter 5 filing requirements and these include: System Access, System Renewal, System Service and General Plant.

System Access Investments

System Access investments facilitate modifications to the distribution system infrastructure, to allow connection of new load or generation customers to the grid, permit joint-use of distribution infrastructure by allowing telecommunication companies to install their service equipment on power lines or underground ducts and allowing relocation of distribution infrastructure installed in public right-of-ways to permit road reconstruction projects. System Access investments are a regulatory obligation for distribution companies (as defined in the Distribution System Code and PUC Distributions Conditions of Service) and therefore these System Access investments receive the highest priority in the overall investment envelope.

To establish the investment level required for System Access, the scope of the required work in this category was identified by estimating the number of anticipated requests for new services both on existing developed streets and in new planned subdivision developments, through direct contact with customers and land developers as well as from the information collected from the municipal planning department. Information related to municipal road reconstruction projects requiring relocation of lines was also obtained from the municipal authorities. Local telecommunication companies were consulted to determine the scope of "make-ready" work for joint-use lines. This category also includes investments needed to comply with the OEB directive to equip all general service customers with >50kW and <500kW demand with MIST meters.

System Service Investments

System Service investments facilitate modifications to the distribution system to ensure that system assets continue to meet their functional needs, efficiently and safely. Electricity distribution companies must invest into capacity upgrades, when required to remove supply system constraints and to ensure electricity delivery at consumer connection points meets the applicable power quality standards (as defined in CSA standards, Distribution System Code). System Service investments may also be required to meet customers' evolving needs for services e.g. introduction of smart grid features to give customers greater access to manage their energy use, improve automation, reduce power restoration times upon asset failures and facilitate connection of renewable generation to the grid. Once it is determined that the existing system is no longer able to meet customers' functional needs, or distribution system standards, these investments become mandatory, gaining the same priority level as the System Access investments.

In order to assess the required level of System Service investments, ability of the distribution grid to supply the existing and anticipated load and generation customers was analysed. PUC Distribution has implemented a number of smart grid features during the previous years, such as smart meters, digital protection systems, voltage regulators and remote-controlled substation switchgear to facilitate automation. System Service investments include input from customers to drive investment decision making. Examples include implementation of voltage regulation improvements and recloser installations in response to customer feedback and needs. As indicated in Section 4, a number of investments under System Renewal will also serve the dual purpose of providing benefits typically derived from System Service investments. As such, there are no investments proposed in this DSP, specifically triggered by System Service objectives.

General Plant Investments

General Plant investments are modifications, replacements or additions to the assets that are not a part of the distribution system comprised of land and buildings used to support day-to-day business and operations activities. PUC Distribution leases its motor vehicle assets rather than owning them, therefore as indicated in Section 4.1.2, and a relatively small level of capital investment is required for renewal of General Plant, equipment and workplace buildings. Additionally, all of PUC Distribution works out of a single consolidated facility which was recently constructed in 2012/2013. General Plant projects are identified and assessed using a combination of inspections, policies and expert knowledge. Investments into building repairs are based on identified deficiencies through inspections of building interior and exterior, doors and fixtures, HVAC, parking lots, security system and building mechanical systems.

System Renewal Investments

System Renewal investments involve replacing and/or refurbishing existing distribution system assets to extend the service life of assets, thereby maintaining the ability of the distribution system to provide customers with a safe and reliable supply of electricity in accordance with customer feedback and prescribed standards and codes (e.g.: Distribution System Code, OEB Scorecard metrics, CSA standards). As the existing assets age, their operating condition degrades and eventually reaches a level where the risk of assets failing in service becomes unacceptable. Since a significantly large part of PUC Distribution’s infrastructure assets have been determined to be in poor or very poor condition, prioritization of investments in the System Renewal category, required a comprehensive risk assessment approach, which is described below in detail.

Figure 8 summarizes the flow chart used to sift through the assets, to objectively identify the assets that present the highest risk of in-service failures so that the investments could be targeted into assets that present the highest risk.

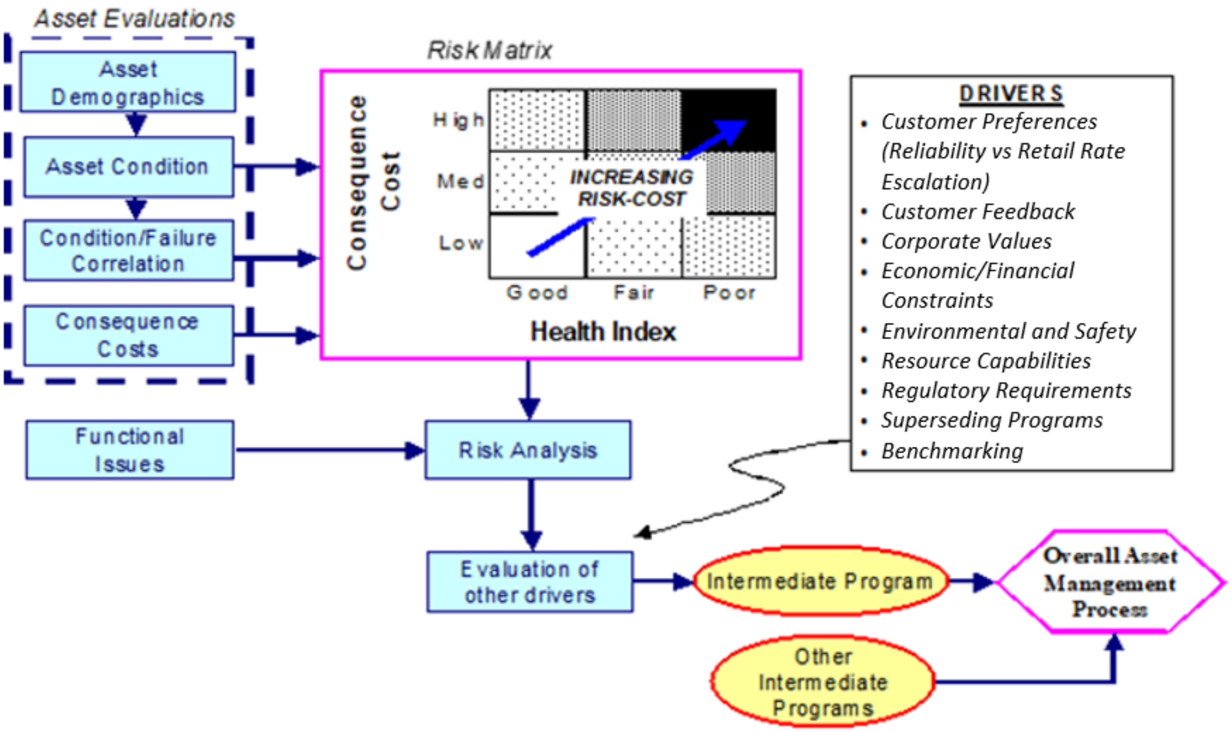


Figure 8: Flow Chart for Asset Management Plan

As shown in Figure 8, for establishing the overall investment level for System Renewal and prioritization of assets selected for renewal, condition assessment of all assets installed in stations, overhead lines and underground distribution systems, was performed by utilizing all available data, indicative of assets' operating condition and probability of failure. The asset condition assessment task was performed under the supervision of the "Engineering and Operations" division.

Data Sets

The data sets employed in prioritization of the investments include:

a) Asset registers, a geographical information system (GIS) station single line diagrams and operating maps, indicating line lengths, conductor sizes, equipment ratings and service age of assets

b) Station peak loading data, indicating equipment capacities and maximum load

c) Equipment inspection data sets, indicating operating condition of distribution system assets, and

d) Substation test result data sets

e) Asset condition assessment report (attached at Appendix B)

While data sets listed under a), b) and c) are maintained and updated by PUC Distribution's Operations and Engineering staff, data sets listed under d) and e) were compiled by third-party contractors and consultants.

Process Description

The asset management process employed for prioritization of investments is described in detail in Appendix B and is briefly summarized below.

Using asset demographic information from PUC Distribution's data sets as an input, service age profiles were developed for all categories of distribution system assets, including distribution stations, as well as the overhead and underground distribution system. PUC Distribution has been maintaining accurate records of station loading for more than 15 years. During preparation of the asset management plan in 2016, historic loading trends were analyzed and anticipated loading levels for distribution stations during the next five years were compared with the station ratings, to identify the potential for distribution system constraints. Results of physical inspections of distribution system performed by PUC Distribution staff were reviewed and supplemented by additional inspections of high risk assets performed by a third-party Professional Engineer. By taking into account asset demographic information, results of physical inspections and in-situ testing, the condition of each major asset in service was assessed. Numeric health indices, normalized to a scale of 100, were used to express the health and condition of assets; and this procedure allowed separation of the assets in "very good", "good" and "fair" condition that require minimal risk mitigation from those in "poor" and "very poor" condition, as illustrated by means of example in Figure 9, which summarizes the condition assessment of wood poles. For all distribution system assets a detailed Asset Condition Assessment is contained in Appendix B.

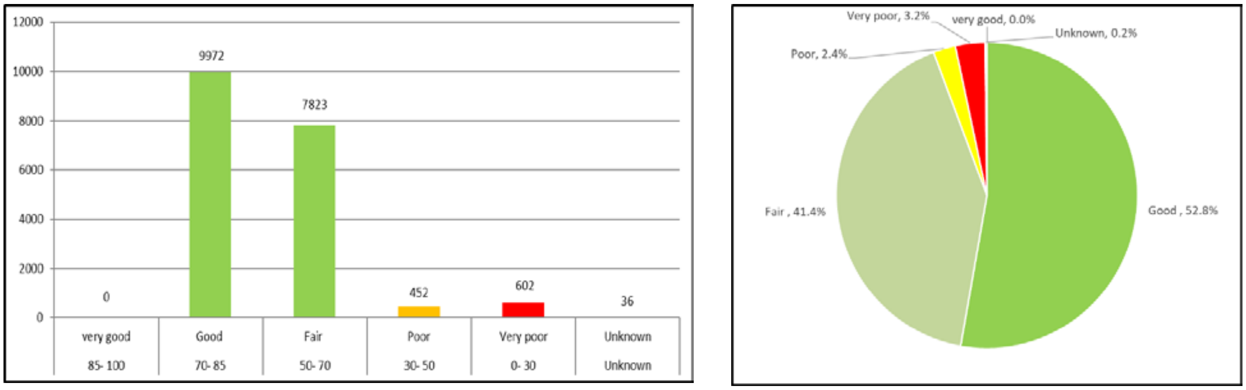


Figure 9: Illustrative Example – Condition Assessment of Wood Poles

For assets determined to be in poor or very poor condition, consequences of asset failures were assessed and those requiring renewal/rehabilitation were ranked in order of priority, with highest consequence of failure being assigned the highest priority. Economic analysis was carried out to determine the optimal response for risk mitigation, by taking into account the cost and life extension provided by renewal and rehabilitation.

In addition to the asset condition and risk assessment, customer engagement sessions were held under the direction of the Customer Engagement and Business Development division to receive feedback and determine customer preferences for service quality level and retail rate escalation. This information was employed by the Finance and Corporate Support division, to establish the overall spending envelope to be applied to the four investment categories. By subtracting the higher priority investments for System Access, System Service and General Plant, available investment level for asset renewal during the DSP period was established by the Operations and Engineering Division. And finally, from the prioritized list of projects, prepared previously through the risk based approach, considered in conjunction with the drivers identified in Figure 8 (i.e.: customer preferences, customer feedback, etc.), a list of projects to be included in the DSP was developed, which could be implemented within the available budget.

3.2 Overview of Assets Managed [5.3.2]

3.2.1 Key Features of the Distribution Service Area [5.3.2 a]

3.2.1.1 Distribution Service Area

PUC Distribution’s service territory as shown in Figure 10 includes most of the City of Sault Ste. Marie, Batchewana First Nation (Rankin Reserve), Prince Township and parts of Dennis Township. Its service territory covers a total service area of approximately 342 square kilometers, including a rural service area 284 square kilometres and an urban service area of 58 square kilometres. The combined population served is approximately 75,300. The service territory includes approximately 29,700 residential customers and approximately 3,800 general customer services for a total of approximately 33,500 customers.

Of the total 743 circuit kilometres of line, 621 kilometres are overhead while the remaining 122 kilometres are underground.

3.2.1.2 Economic Growth

According to Statistics Canada census data, the City of Sault Ste. Marie’s has experienced about a 2.1% decline in population between 2011 and 2016. The pace of economic growth is not expected to change during the next 5-year period, covered by the DSP.

3.2.1.3 Climate

The climate is typical of most towns in Northern Ontario and reaches temperature extremes of -40˚C during winter and +40˚C in summer. The normal monthly temperatures vary from -15˚C during winter and +25˚C in summer, with approximately 10 days of precipitation in a month. Both overhead and underground distribution systems are employed in PUC Distribution's service territory. The presence of a number of different soil types, the Canadian Shield, numerous clays, and muskeg often make excavation activities a challenge, particularly for installation of underground distribution systems. The region is vulnerable to commonly occurring strong wind storms, lake-effect snow and ice loading from Lake Superior, which poses a challenge to overhead lines. PUC Distribution's entire service territory is located within the CSA heavy loading area as described in CSA 22.3 No. 1-15 Overhead Systems. Accordingly, the corresponding CSA referenced heavy loading conditions of radial thickness of ice; horizontal wind loading and temperature are accounted for in line designs. Lines with the highest risk of failure consequences are included in the asset renewal program proposed in this DSP.

3.2.1.4 Electrical Loading

Electrical loading on the grid peaks during the winter in this region. Due to expansion of the natural gas distribution network and implementation of the CDM programs over the recent past, winter peak loading on the electricity grid has reduced, while the relatively small decline in the population has resulted in a modest increase during summer peak loading. As a result, the overall peak demand on the electricity has been trending downwards and no capacity constraints are anticipated during the next five years.

Although a number of investments in the System Renewal category will introduce many smart grid features during rebuild of the system and therefore will provide benefits typically provided by investments in System Service category, there are no investments in this DSP, for which System Service is considered the sole motivation and therefore no investments are shown in the System Service category.

3.2.1.5 System Voltage Levels (Voltage Conversion)

Approximately 25 years ago, PUC Distribution started a program to gradually upgrade its distribution system from 4.2 kV to 12.5kV. When the existing 4.2 kV infrastructure reaches the end of its service life, rather than like for like replacement of 4.2 kV rated equipment with 4.2 kV rated equipment, the voltage is upgraded to 12.5 kV, which results in greater operating efficiency. A vast majority of the distribution system has already been upgraded to 12.5 kV and at present relatively small pockets of service area with 4.2 kV network remain. Most of the existing distribution infrastructure operating at 4.2 kV is at the end of its service life and the poor condition of equipment has been resulting in frequent equipment failures with adverse impacts on reliability. Maintaining a distribution system with two operating voltages also results in duplication of lines and economic inefficiencies due to system energy losses. Therefore, this DSP includes investments to retire the remaining network equipment operating at 4.2 kV from the grid and upgrade all of the remaining line sections to 12.5 kV.

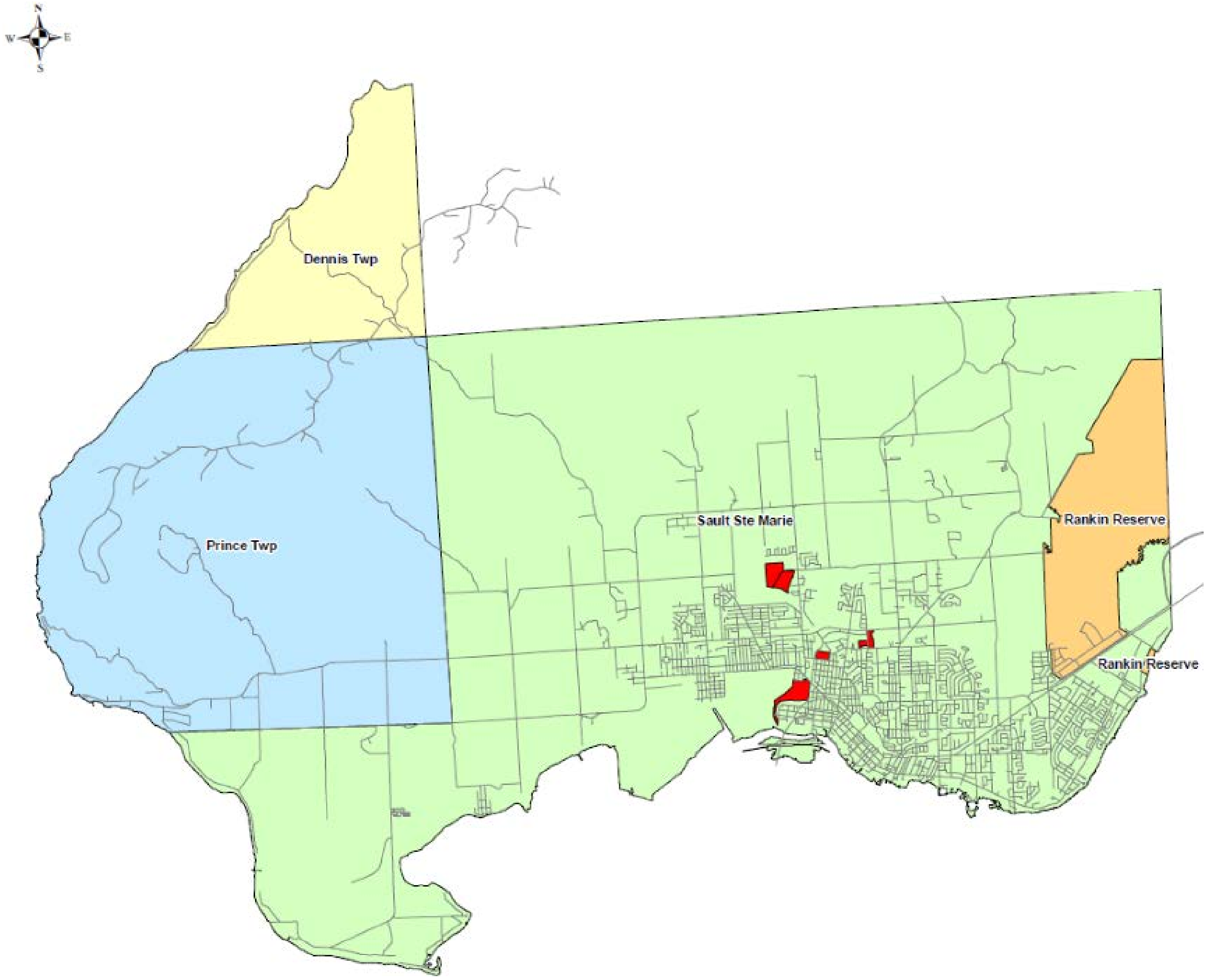


Figure 10: PUC Distribution Service Territory

3.2.2 Description of System Configuration [5.3.2 b]:

PUC Distribution owns and operates two transformer stations - TS1 and TS2, which step down power received from the transmitter at 115 kV to 34.5 kV. The 34.5 kV feeders supply a total of 12 distribution stations, which step down power from 34.5 kV to 12.5 kV. There are also two additional distribution stations; one of which steps down from 34.5kV to 4.2kV, the second steps down from 34.5kV to both 12.5kV and 4.2kV. A third 12.5kV to 4.2kV station, Substation 14 has been recently been retired. The remaining two 4.2 kV distribution stations are planned to be retired from service, upon completion of the distribution voltage upgrade program, during the next five years. Figure 11 below shows the geographic locations of transformer stations and distribution stations, within the PUC Distribution's service territory.

Figure 11: Distribution Station Locations

Table 15 shows the power transformer ratings and number of 34.5 kV feeders at each of the 115/34.5 kV transformer stations.

Table 15: 115/34.5kV Substation Ratings

Transformer Station	Capacity	Number of 34.5 kV Feeders
TS 1	4x30 MVA	5
TS 2	4x30 MVA	5

In addition to the four outgoing feeders, TS-1 also supplies Substation 19, which is located at the same site as TS-1. Both transformer stations are also equipped with power factor correction shunt capacitors. TS-1 employs shunt capacitors of 20 MVAR rating as well as a recently installed IESO controlled 7MW/+/-7MVAr/7MWh energy storage facility to provide dynamic Volt/VAR control. TS-2 employs shunt capacitors of 40 MVAR rating.

Table 16 shows the power transformer ratings and number of feeders at each of the distribution stations.

Table 16: Substation Ratings

12 kV Stations	Capacity	Number of 12.5 kV Feeders
Substation 1	2x10 MVA	4
Substation 2	2x10 MVA	4
Substation 4	1x10 MVA	2
Substation 10	2x10/13.3 MVA	4
Substation 11	2x10 MVA	4
Substation 12	2x10 MVA	4
Substation 13	2x10 MVA	4
Substation 15	2x10 MVA	4
Substation 16	2x7.5 MVA	4
Substation 18	2x7.5 MVA	4
Substation 19	2x10 MVA	4
Substation 20	2x10 MVA	4
Substation 21	2x10 MVA	4

4.2kV Stations	Capacity	Number of 4.2 kV Feeders
Substation 4	1x10 MVA	2
Substation 5	2x5 MVA	2

Major assets employed on the overhead and underground distribution network are summarized in Table 17. As indicated, the power supply network employs overhead lines operating at 115kV, 34.5 kV, 12.5 kV, 7.2 kV, 4.2 kV and 2.4 kV as well as low voltage (LV), i.e. less than 750V, and it employs insulated cable circuits installed in duct and direct buried configurations, operating at 34.5kV, 12.5 kV, 7.2 kV, 4.2 kV and 2.4 kV.

Table 17: PUC Distribution's Distribution System Assets

Asset	Quantity	Units
3-Phase 115 kV Overhead lines	15.5	km
3-Phase 34.5 kV Overhead lines	74.4	km
3-Phase 12.5 kV Overhead lines	278	km
3-Phase 4.2 kV Overhead lines	23.5	km
3-Phase LV Overhead lines	38.7	km
1-Phase 7.2 kV Overhead lines	219.4	km
1-Phase 2.4 kV Overhead lines	8.3	km
1-Phase LV Overhead lines	42.1	km
Number of poles on OH lines	12683	#
34.5 kV, 3-ph, UG, Cable Circuits	24.5	km
12.5 kV, 3-ph, UG, Cable circuits	49.2	km
7.2 kV, 1-ph, UG, Cable circuits	45.6	km
4.2 kV, 3-ph, UG, Cable circuits	1.4	km
2.4 kV, 1-ph, UG, Cable circuits	1.4	km
Number of 1-ph pole mounted transformers	5167	#
Number of 3-ph pad mounted transformers	547	#
Number of 1-ph pad mounted transformers	391	#
Number of submersible transformers	517	#
Number of pad-mounted switchgear	23	#
Number of K-bar Units	130	#
Number of concrete structures (pads and vaults)	1041	#

Table 18 provides information on the number of feeders that are installed in overhead (OH) or underground (UG) or mixed OH/UG configurations.

Table 18: Number of Feeders Installed in OH or UG Configurations

(a) 35 kV Feeders

Source Station	Total Number of Feeders	Number of OH Feeders	Number of UG Feeders	Number of Mixed OH/UG Feeders
TS-1	5	5	0	0
TS-2	5	2	0	3

(b) 12.5 kV Feeders

Source Station	Total Number of Feeders	Number of OH Feeders	Number of UG Feeders	Number of Mixed OH/UG Feeders
DS-1	4	1	1	2
DS-2	4	2	1	1
DS-4	2	2	0	0
DS-10	4	4	0	0
DS-11	4	3	0	1
DS-12	4	1	1	2
DS-13	4	3	0	1
DS-15	4	2	1	1
DS-16	4	1	0	3
DS-18	4	1	0	3
DS-19	4	2	0	2
DS-20	4	2	0	2
DS-21	4	0	0	4

(c) 4.2 kV Feeders

Source Station	Total Number of Feeders	Number of OH Feeders	Number of UG Feeders	Number of Mixed OH/UG Feeders
DS-4	2	1	0	1
DS-5	2	2	0	0

3.2.3 Asset Demographics and Condition Assessment [5.3.2 c]:

The asset management plan, prepared in September 2016 and attached as a stand-alone report in Appendix B, provides complete demographic and asset condition information on fixed assets employed in PUC Distribution's substations, overhead distribution network and the underground distribution system. The asset condition assessment report documents the condition of all major assets in units of health indices and provides ranking of assets in designations rated "very good", "good", "fair", "poor" and "very poor". In determining the health indices of assets, all available information relevant to the assets' health, including age, results of visual inspections and results of diagnostic testing when available, have been utilized.

"Very Good" asset condition represents brand new asset in perfect operating condition, with no impairment. "Good condition" indicates an asset with service life equal to less than 25% of its typical useful life and with no impairment and no noticeable drop in operating performance. "Fair Condition" indicates an asset with service life equal to more than 25% but less than 80% of its typical useful service life, with normal wear and asset operating performance within acceptable tolerances and no significant impairment. "Poor Condition" signifies an asset with service life greater than 80% of its typical useful service life, appreciable wear or significant impairment in asset condition causing its performance to degrade below acceptable levels and presenting high risk of asset failure unless major repairs or asset rehabilitation is performed to restore asset condition to “Fair”. “Very Poor Condition” signifies an asset with serious impairment to its critical components and the asset presents very high risk of failure. Assets in “very poor” condition cannot be economically repaired and renewal is the only option to restore their operating condition.

All of the information provided in the following sections on asset condition is based on the asset condition assessment performed in September 2016.

3.2.3.1 Condition Assessment of Substation Assets:

In substations, power transformers and switchgear (complete with protection and control equipment) are the critical components, essential to safe and reliable operation of station functions. Figure 12 and Figure 13, reproduced below from the AM Condition Assessment report, indicate the existing condition of power transformers and switchgear employed at PUC Distribution’s 115/34.5 kV transformer stations and 34.5/12.5 kV distribution stations.

Due to the advanced service age, combined with “poor” or “very poor” operating condition of a vast majority of the power transformers and switchgear sets employed at both of the 115/34.5 kV transformer stations (TS-1 and TS-2), both of these stations require complete rebuild with new power transformers, switchgear, protection and control equipment. Rebuilding of these two transformer stations requires significant front-end planning and engineering before construction can begin, to ensure that supply system security is not adversely impacted during construction. Planning is also required to comprehensively assess all available development alternatives with the objective of selecting the optimal alternative for re-development meeting the future needs of PUC Distribution’s customers during the next 40-50 years. Therefore, capital investment into a planning and engineering study with the objective of reviewing all practical development options through completion of conceptual designs and recommending the optimal transformer station development alternative for implementation is proposed in this DSP.

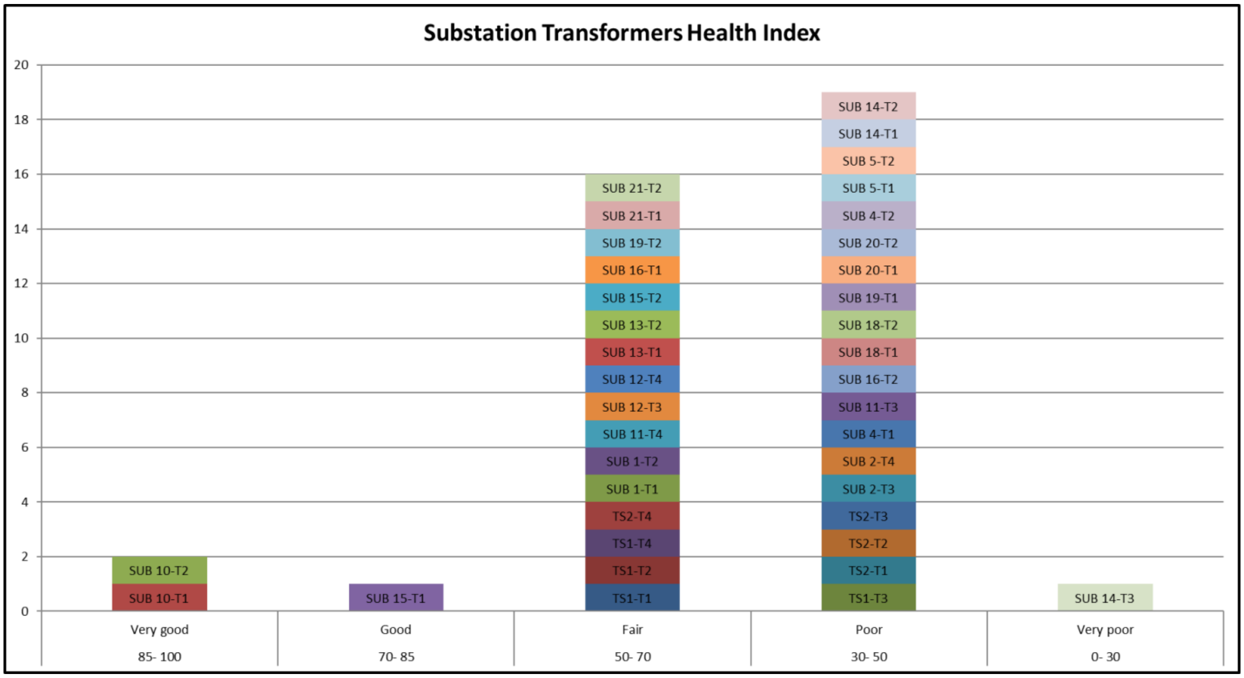


Figure 12: Substation Power Transformers - Condition Assessment

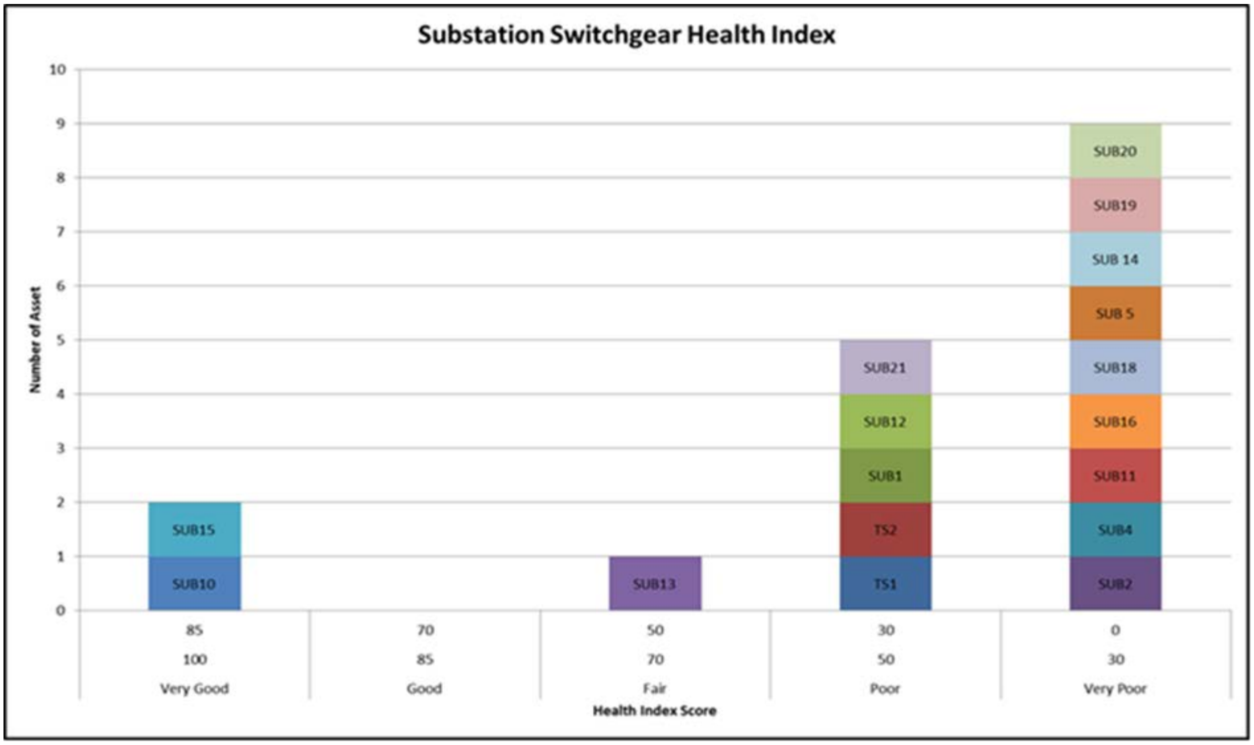


Figure 13: Substation Switchgear - Condition Assessment

Due to the “poor” or “very poor” condition of the power transformers, switchgear and other associated assets at seven of the twelve existing 34.5/12.5 kV distribution stations, these stations have been determined to be in “poor” or “very poor” condition, requiring complete rebuild of these stations during the next 10 years. However, given current revenue levels and lack of projected customer load growth it will be necessary to gradually ramp up the distribution station rebuild initiative over a longer period of time. This DSP includes capital investments for rebuild of two of the stations during next five years, those that present the highest risk of failure. The rebuild of remaining stations in “poor” or “very poor” condition has been deferred, for inclusion in subsequent DSPs.

For the two transformer stations and the distribution stations determined to be in “poor” or “very poor” condition but not included in the renewal program in the current DSP, PUC Distribution plans to manage the risk of equipment failures through proactive monitoring and testing of equipment and performing repairs, refurbishment and replacement of components when they fail, and this DSP includes funding for repair, refurbishment and component replacement activities.

3.2.3.2 Condition Assessment of Overhead Line Network Assets:

PUC Distribution’s overhead distribution network employs approximately 391 km of 3-phase and approximately 230 km of 1-ph lines, all operating at 115kV, 34.5 kV, 12.5kV, 7.2kV, 4.2kV and 2.4 kV. Figure 14 and Figure 15, respectively, show the age profile of overhead lines and as shown, approximately 28.5% of the overhead lines will reach the end of their design service life of 45 years during the next five years. As the lines approach the end of their design life, all line components including wood poles, mounting hardware and conductors experience degradation of strength and pose a high risk of failure in service when subjected to design loading during wind and ice storms. To mitigate this risk, these lines will require rebuild with new poles and conductors.

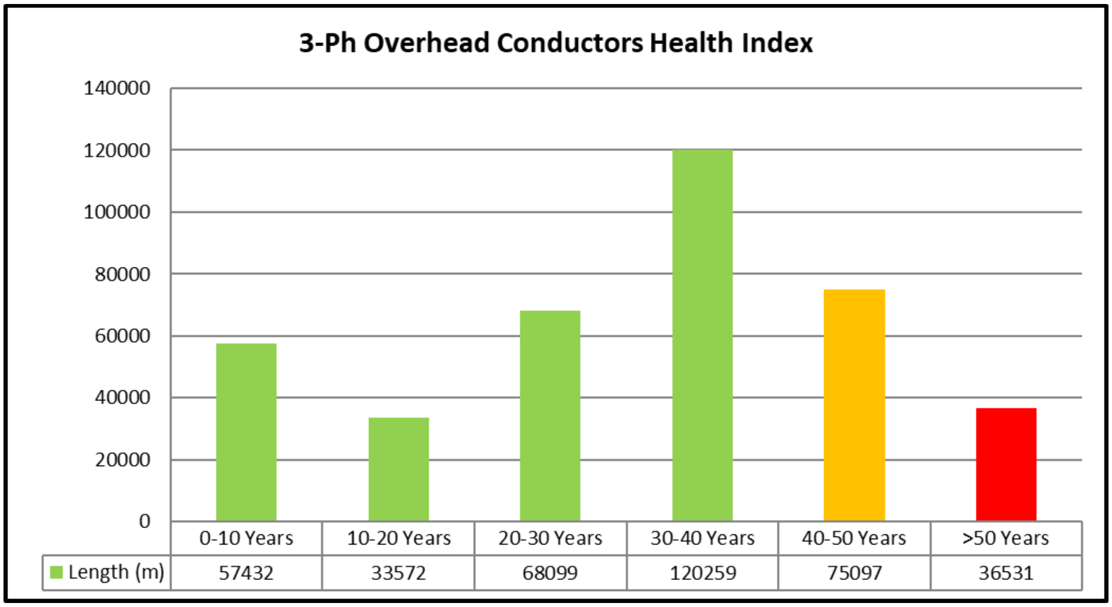


Figure 14: Age Profile – 3-Ph MV Overhead Lines

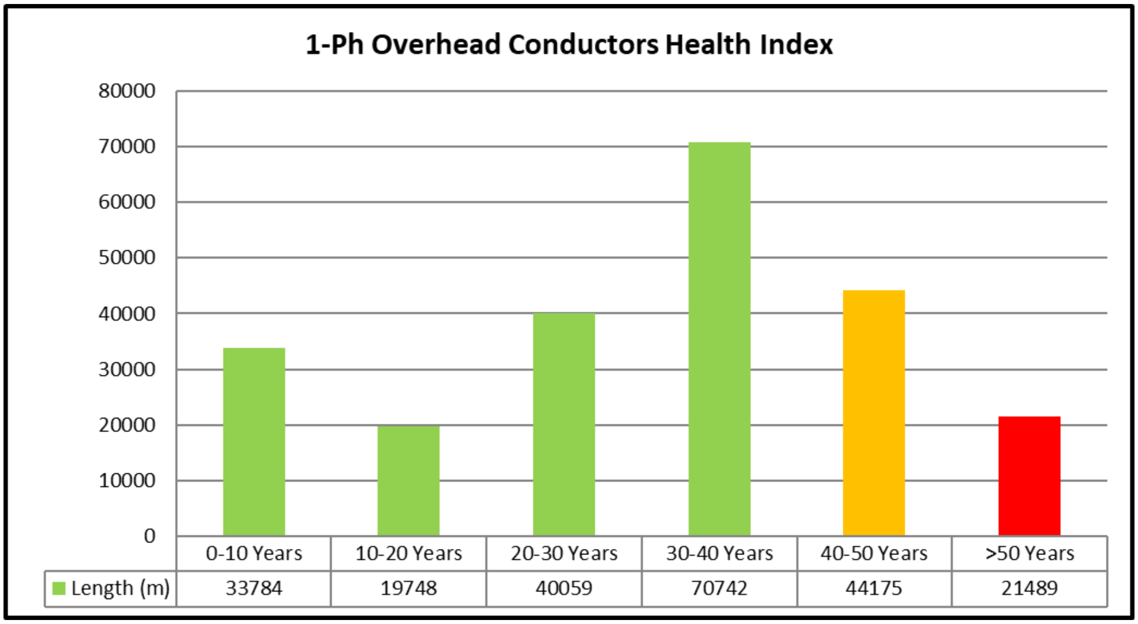


Figure 15: Age Profile – 1-Ph, MV Overhead Lines

Rather than proposing re-construction of all overhead lines that have reached the end of their design life, this DSP includes a small subset of the lines determined to be at the end of their service life. The lines included in the DSP for renewal have been prioritized by taking into account the probability of failure of a line section and the impact of line failures on public safety, supply reliability and operating costs. Since weakened poles with reduced structural strength, line sections with restricted conductors with reduced tensile strength, and the lines operating on 4.2 kV system, which are well past the end of their typical useful life, pose the highest risk of failure in service, priority for overhead line renewal has been given to projects, involving:

- line sections with poles in “very poor” condition,
- line sections built with restricted conductor, and
- lines determined to be in “very poor” condition and currently operating at 4 kV, which will undergo voltage upgrade upon reconstruction.

There are approximately 12,600 wood poles and about 83 other types of poles (including steel, concrete and fiberglass) employed on PUC Distribution’s overhead lines. In order to identify poles in “poor” or “very poor” condition PUC Distribution periodically conducts in-situ testing of poles. The existing condition of the poles in 2016 is indicated in Figure 16. This DSP proposes renewal of approximately 30 poles, annually, determined to be in “very poor” condition, through pole testing.

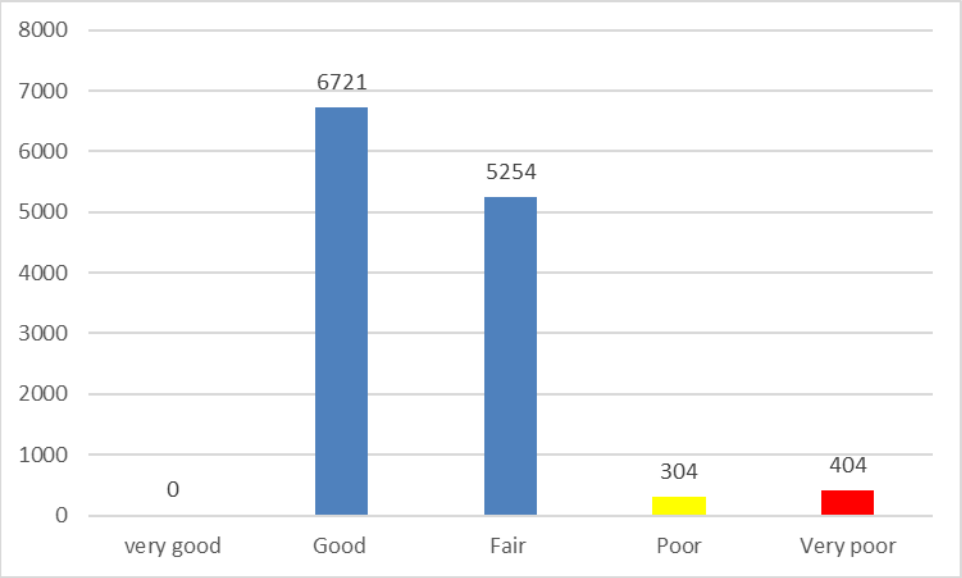


Figure 16: Overhead Line Pole - Condition Assessment

Copper and aluminum conductors with smaller cross-section area, and more specifically #6 AWG and #4 AWG (copper or aluminum) conductors have lower tensile strength in relation to larger conductors typically used in overhead line construction. Under tension, the tensile strength of these smaller cross-section conductors further degrades with service age. These conductors are known to fail in service and when they fail, the downed lines pose a very serious safety risk for public. #6 AWG and #4 AWG conductors are no longer used for applications requiring conductor tensioning over full spans on overhead lines, and virtually all Canadian utilities have adopted programs to proactively phase out lines built previously with restricted conductors.

As shown in Figure 17 and Figure 18, PUC Distribution had identified approximately 8 km of 3-phase lines and approximately 60 km of 1-phase lines on its distribution network, constructed with restricted conductors and adopted a line renewal plan to phase out the restricted conductor on lines starting in 2009. On the PUC Distribution system the restricted conductor is primarily #6AWG copper. Up to the end of 2015, approximately 26% of the lines with restricted conductor had been phased out. Work on rebuilding of the remaining lines with restricted conductor is scheduled to continue during this 5-year DSP, with a target date of 2027 for complete elimination of all restricted conductor lines from the network. The lines for renewal are prioritized based on their location and the risk of public exposure to the downed lines.

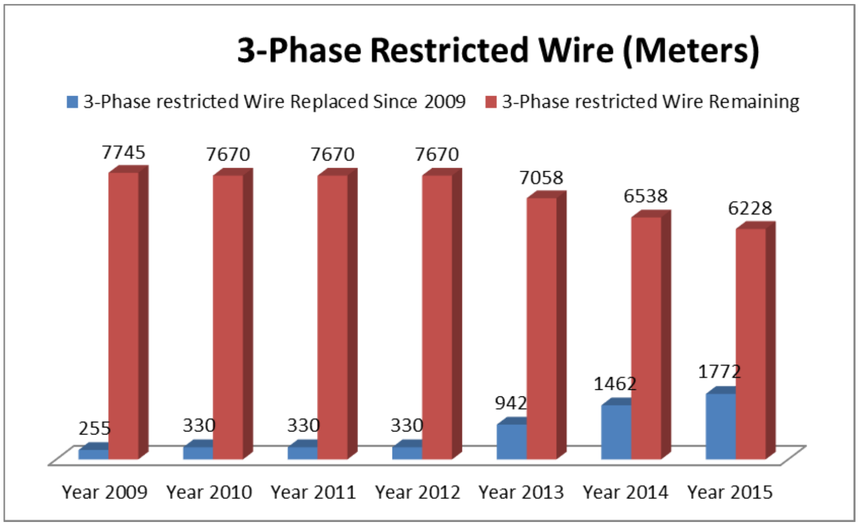


Figure 17: 3-Phase Lines with Restricted Wire on PUC System

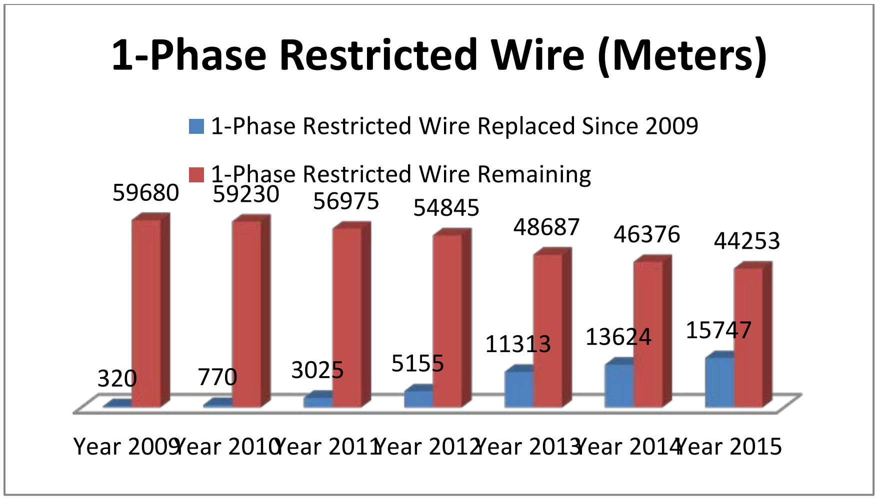


Figure 18: 1-Phase Lines with Restricted Wire on PUC System

Overhead lines employed on 4 kV distribution system are the oldest infrastructure components on PUC Distribution Inc.'s power supply network. Most of these lines have reached a service age of 50 or 60 years, well past their design life and they present the highest risk of failure in service. PUC Distribution has been gradually retiring from service the 4 kV lines at the end of their service life and rebuilding the lines with voltage upgrade to 12.5 kV. This DSP provides funding for rebuilding of 4 kV lines with voltage upgrade and when the proposed projects are implemented, it would allow PUC Distribution to retire all infrastructure operating at 4 kV by 2022.

Because the planned overhead line renewal projects described above, target only a subset of the lines determined to be in poor and very poor condition, this DSP also includes modest funds for renewal of components that are identified to be in unsafe condition during one-third plant inspections in accordance with the DSC as well as for emergency repairs and renewal of components that fail in service.

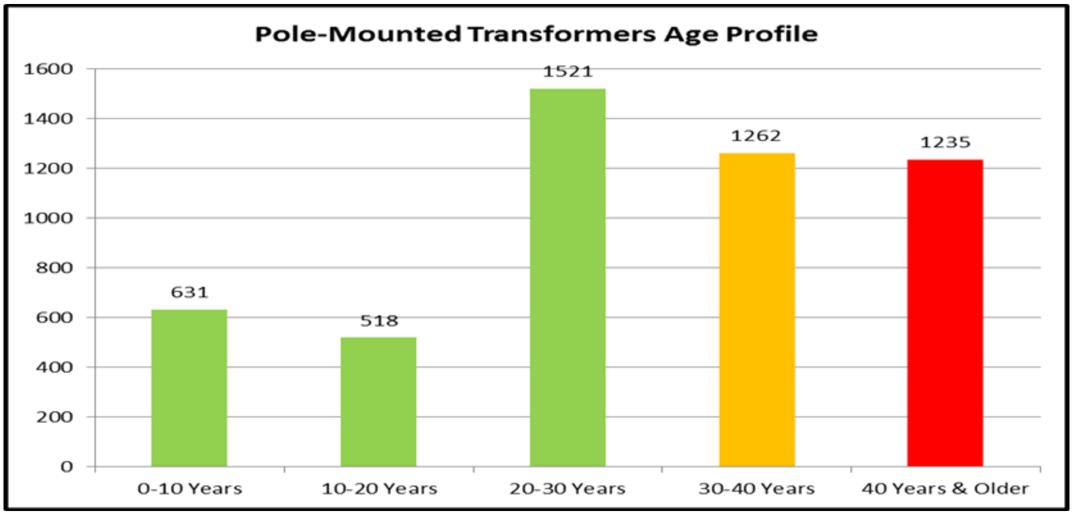


Figure 19: Age Profile of Pole-Mounted Distribution Transformers

Figure 19 indicates the age profile of pole mounted distribution transformers employed on the overhead distribution network. PUC Distribution employs "run-to-failure" strategy for distribution transformers due to the relatively low impact of transformer failures on reliability. Current PCB regulations in Canada permit the use of pole mounted distribution transformers containing PCB content in oil of over 50 parts per million and this use can continue up to December 31, 2025. Beyond that date, all distribution transformers must have a PCB level below 50 parts per million. To comply with this regulation, distribution utilities will need to either (a) test all suspect transformers (purchased prior to 1980) for PCB content and replace those containing PCBs, or (b) replace all suspect transformers (purchased prior to 1984). This DSP includes budgetary provision for testing suspect distribution transformers for PCB content but replacing transformers that fail the PCB test have been deferred to beyond 2022.

3.2.3.3 Condition Assessment of Underground Distribution Assets:

The underground distribution network at PUC Distribution employs approximately 75 km. of 3-phase cable circuits and approximately 47 km of 1-phase circuits. Figure 20 shows the age profile of distribution cable on 3-phase circuits, operating at 34.5 kV and 12.5 kV and Figure 21 shows the age profile of single phase and two-phase cable circuits, operating at 12.5 kV circuits. As shown, approximately 25% of the cable has reached service age of greater than 40 years. There are no practical tests available which could be economically performed in field to accurately assess the remaining useful life of cables. However, XLPE insulated cables, which are typically employed on underground distribution systems generally begin to experience an increase in failure rates when they get past 40 years of service age. It is also noteworthy that a vast majority of the cables installed prior to 1990 were installed in direct buried configuration. Cable failures in direct buried configurations have significantly larger impact on reliability than failures that occur where cables are installed in duct. All cable circuits past 40 years of service age are considered in poor condition. This DSP includes some funding for proactive replacement of underground cables with priority given to direct buried cable circuits as well as in voltage conversion areas. However, it is expected this will require more significant ‘ramping up’ of investment beyond 2022 to keep a failures rates level.

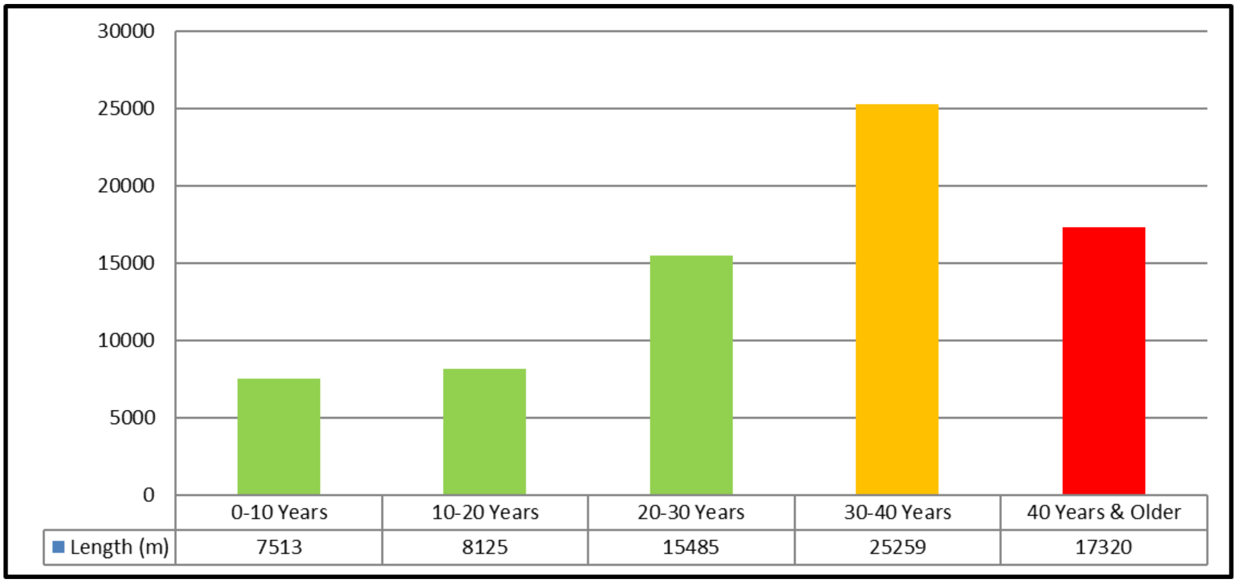


Figure 20: Age Profile of 3-Phase Cables on 34.5 kV and 12.5 kV System

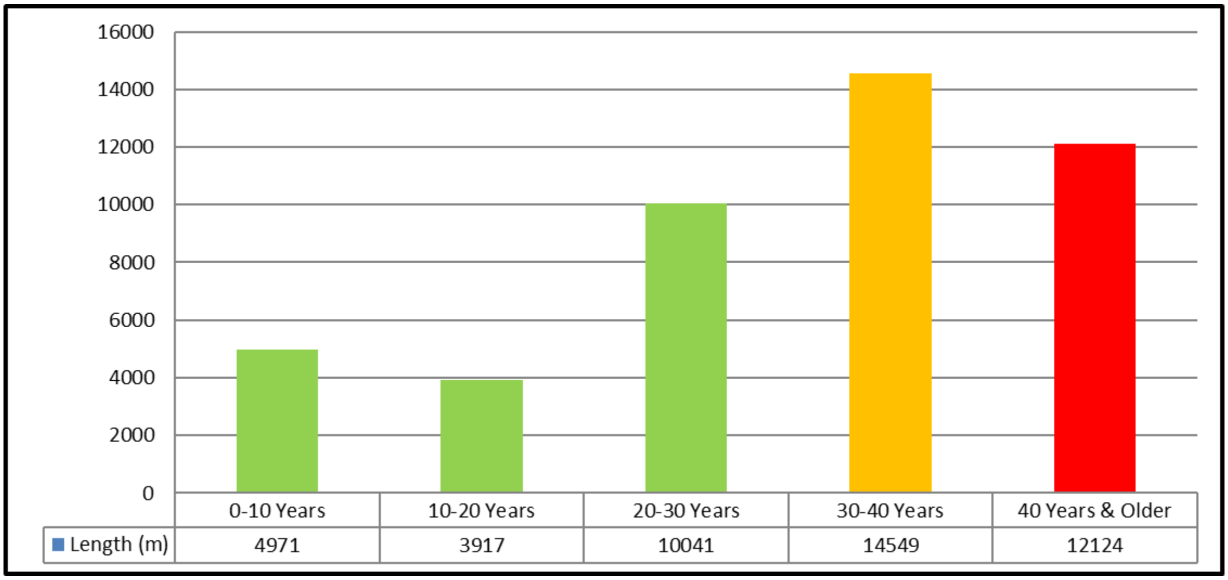
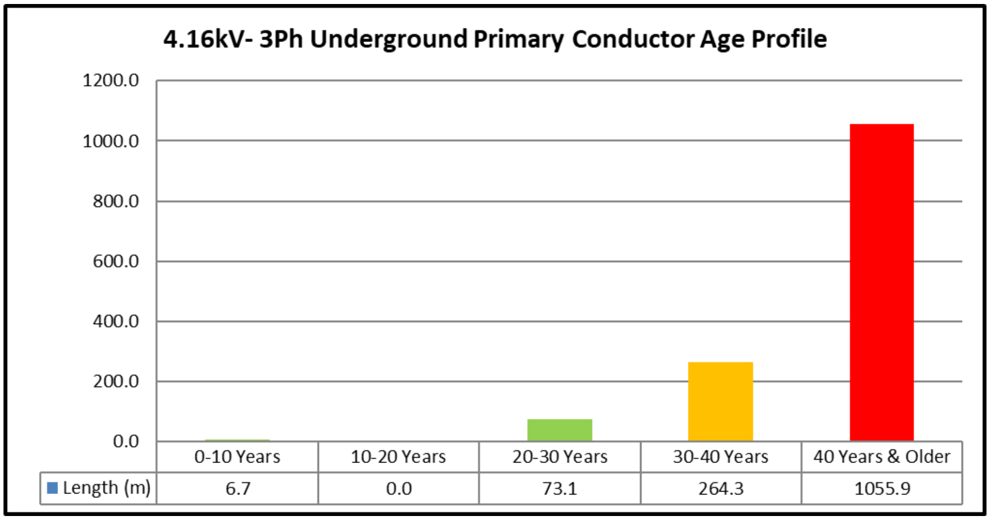


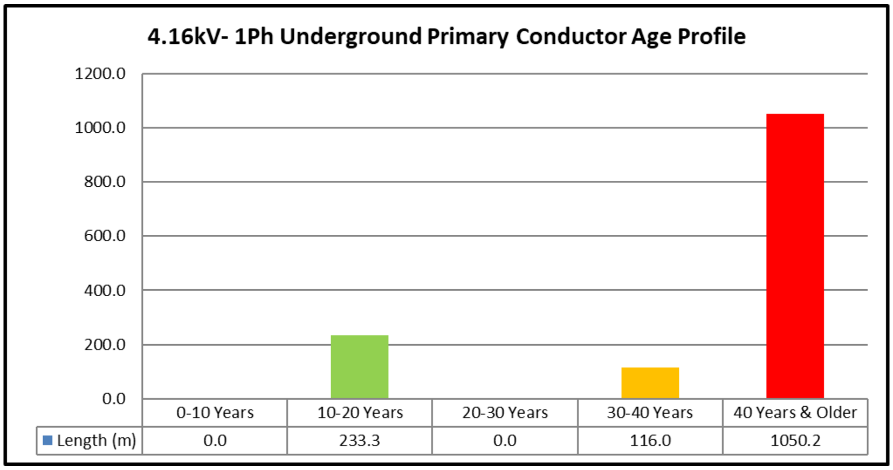
Figure 21: Age Profile of 1-Phase Cables on 12.5 kV System

Figure 22 and Figure 23, respectively, show the age profile of distribution cables employed on 3-phase and 1-phase circuits operating at 4.2 kV. As indicated, a majority of these cables are already past their 40-year typical useful service life. These cables will be removed from service when these service areas are upgraded to 12.5 kV and funding has been provided in this DSP for their renewal. The relatively small amount of cable circuits, with service age of less than 20 years on 4.2 kV system, are rated for use on 12.5 kV (in anticipation of the voltage conversion) and these circuits will remain in service after voltage conversion.



	0-10 Years	10-20 Years	20-30 Years	30-40 Years	40 Years & Older
Length (m)	6.7	0.0	73.1	264.3	1055.9

Figure 22: Age Profile of 3-Phase Cables on 4.2 kV System



	0-10 Years	10-20 Years	20-30 Years	30-40 Years	40 Years & Older
Length (m)	0.0	233.3	0.0	116.0	1050.2

Figure 23: Age Profile of 1-Phase Cables on 4.2 kV System

Figure 24, Figure 25 and Figure 26, respectively, show the age profile of 3-ph pad-mounted transformers, 1-ph pad-mounted transformers and 1-ph submersible vault mounted transformers employed by PUC Distribution to serve customers supplied from the underground distribution system.

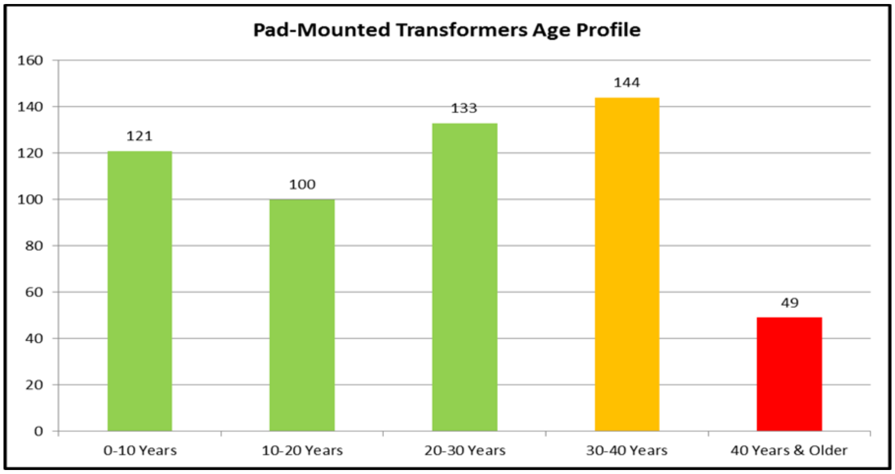


Figure 24: Age Profile of 3-Phase Pad-mounted Distribution Transformers

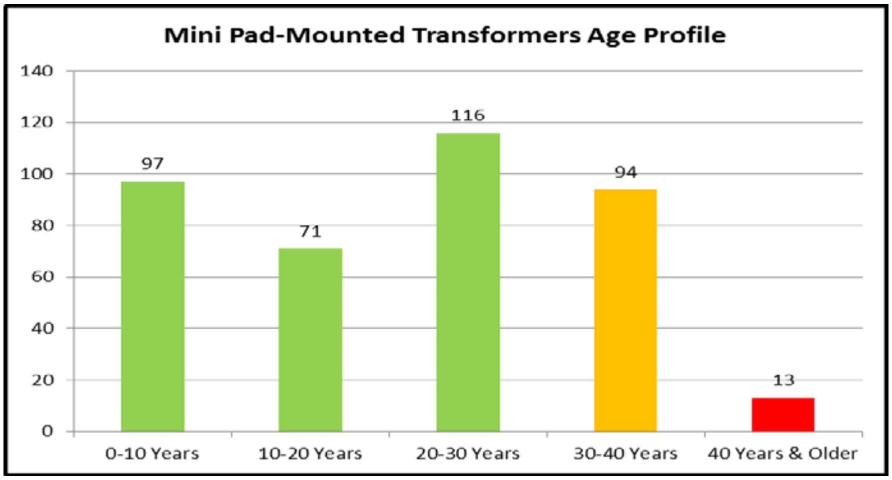


Figure 25: Age Profile of 1-Phase Pad-mounted Distribution Transformers

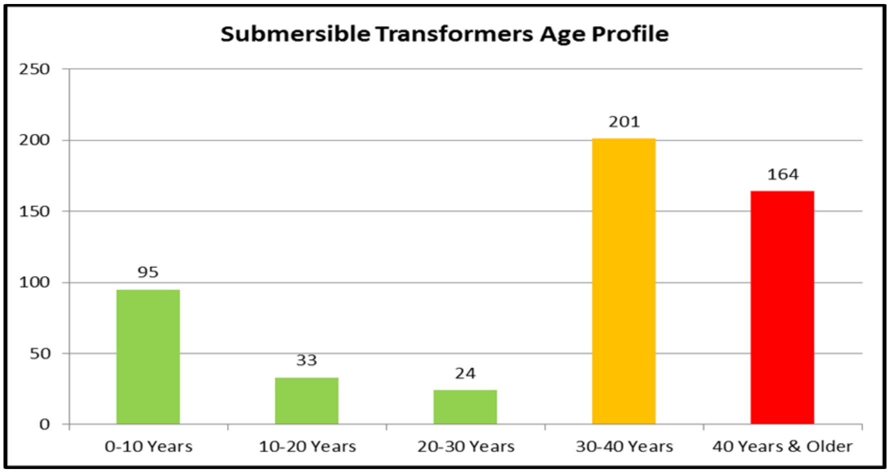


Figure 26: Age Profile of Vault-mounted Submersible Distribution Transformers

The Distribution System Plan does not target proactive replacement of distribution transformers, but rather a reactive approach, meaning transformers will be replaced after they have experienced a failure in service.

For switching of underground circuits, PUC Distribution Inc. employs live-front pad-mounted switchgear as well as ‘K-bar’ junction units. Based on the service age and visual inspections, five of the pad mounted switchgear units were determined to be in “poor” or “very poor” condition in 2016, as shown in Figure 27. This DSP includes funding for renewal of the pad-mounted switchgear found in very poor condition. Upon renewal, the live front switchgear will be replaced with dead front switchgear, providing enhanced worker safety.

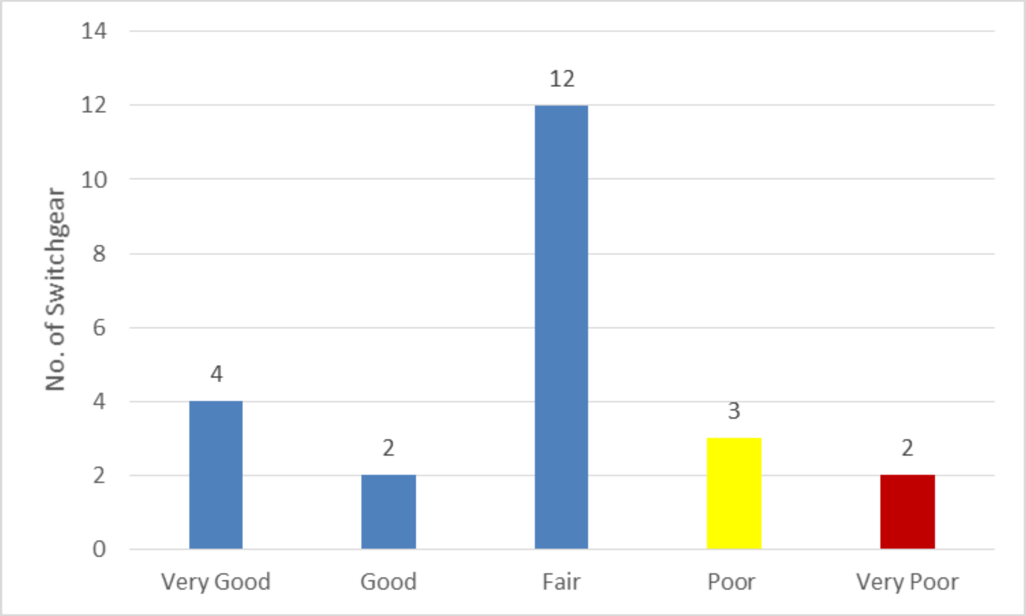


Figure 27: Condition Assessment of Pad-Mounted Switchgear

Figure 28 shows the age profile of junction units. As shown, 89 of the junction units had reached a service age of more than 35 years and these units will exceed the typical useful design life of 40 years during the next five years. During one-third plant inspections performed in compliance with Regulation 22/04, condition of the junction units will be assessed for safety and the DSP contains a modest budget to replace those found in unsafe operating condition.

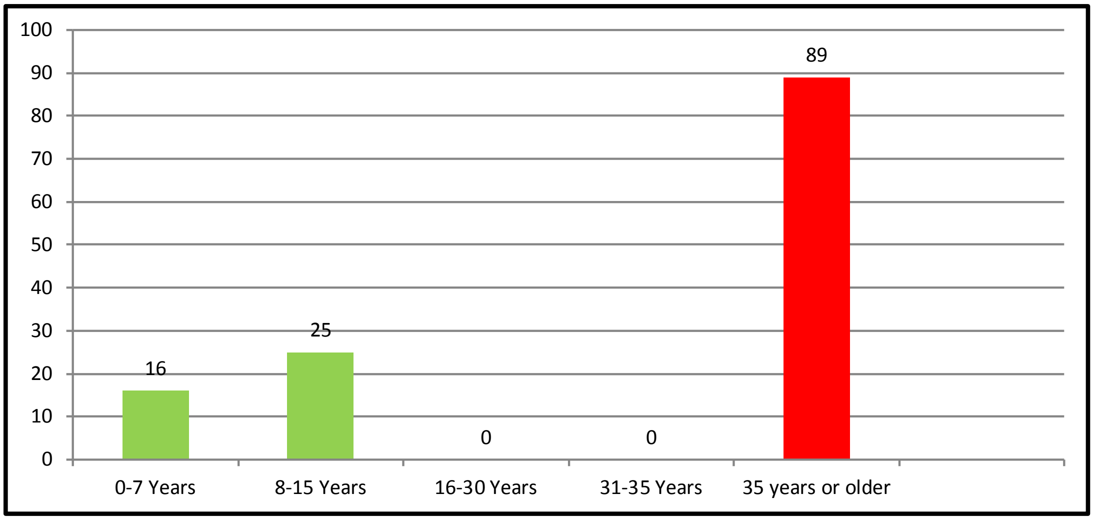


Figure 28: Age Profile of K-bar Units

PUC Distribution's underground distribution system employs concrete chambers for various functions, including cable pull-boxes and manholes, mounting bases for switchgear and K-bar junctions, submersible transformer vaults, splice vaults and general-purpose equipment vaults. As shown in Figure 29, approximately 23% of the chambers are currently more than 50 years old. Physical inspections of the concrete structures indicate, a large percentage of these old vintage chambers are functionally obsolete. From the point of view of worker safety, the submersible transformer vaults and splice vaults present a challenge in that outages are required to complete maintenance work increasing costs and inconveniencing customers. Accordingly, funds have been included to make progress in the replacement of these vaults.

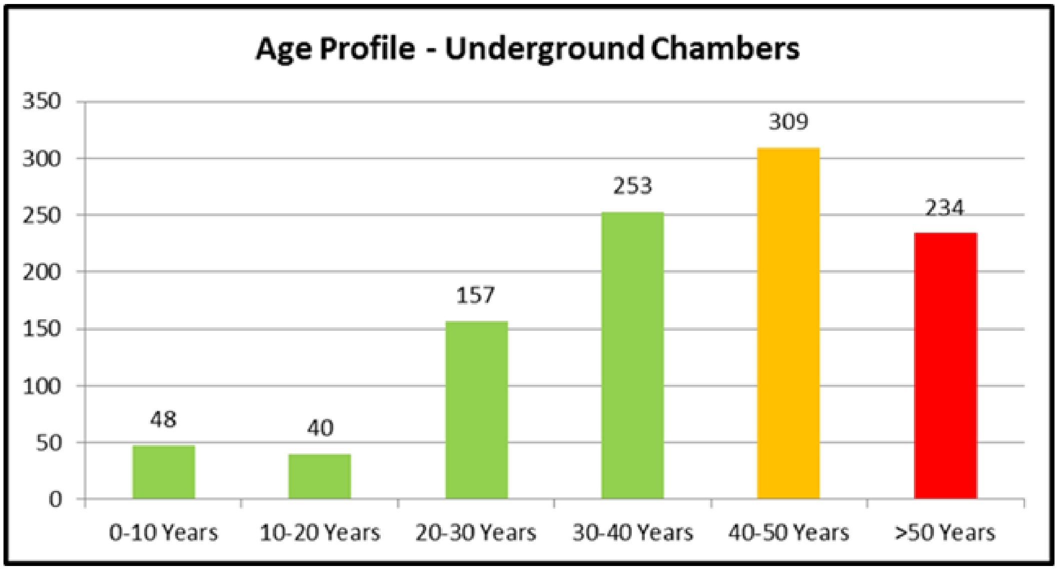


Figure 29: Age Profile of Underground Chambers

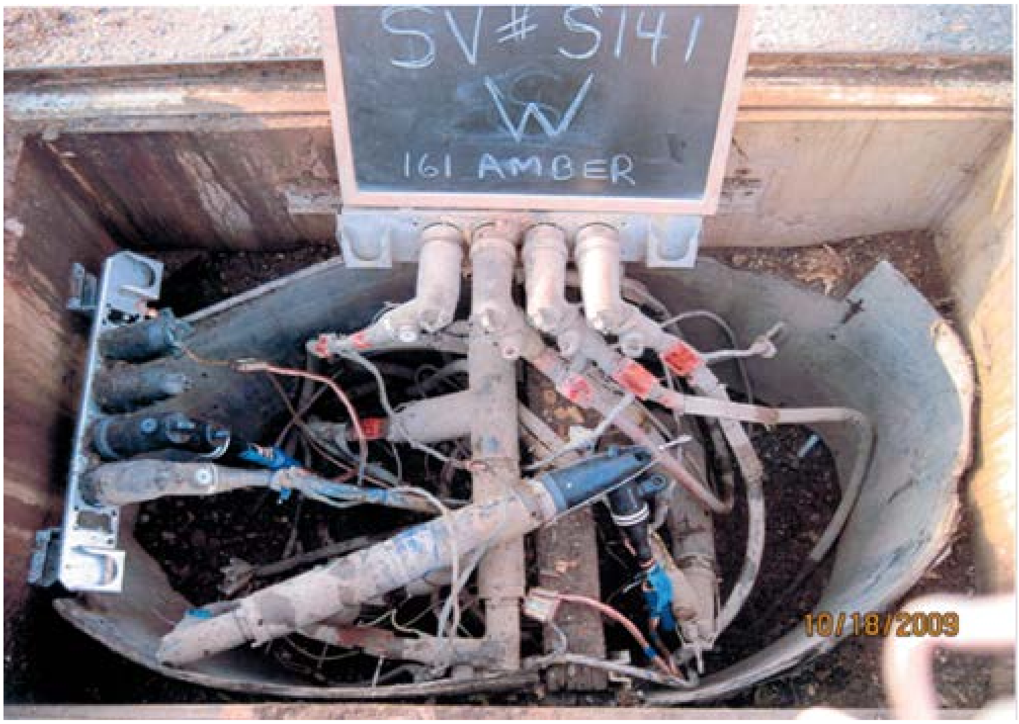


Figure 30: Typical Switching/Splice Vault on PUC Distribution System

The submersible transformer vaults and splice vaults of inadequate size and without concrete floors, as shown in Figure 30, present the highest risk to workers and therefore, have been given a priority for reconstruction in this DSP. After reconstruction, these vaults will be converted to vaults to support pad mounted equipment, mounted above grade.

In addition to the planned underground distribution System Renewal projects described above, this DSP also includes modest funds for emergency repairs and renewal of components that fail in service, during the next five years.

3.2.4 Capacity Assessment of Existing System [5.3.2 d]:

The chart in Figure 31 shows the historic peak load during each month over the past five years supplied from the PUC Distribution’s supply network. As shown, the electrical load served by the supply system peaks during the winter season, typically in the month of January. The peak load served from the system during summer months, is typically about 55% less than the winter peak load. This prevailing seasonal loading pattern is desirable for avoiding equipment overloads, because loading capacity of the power equipment is higher during the winter months due to lower ambient temperature, when peak load occurs.

The figure also indicates a negative time trend in peak electrical demand on the distribution network. The peak load served from the system has experienced a decrease at the rate of approximately 2.8%, annually, due to a number of reasons, including the multiple CDM initiatives implemented by residential and general service customers, expansion of natural gas distribution network in the region and shifting of heating loads from electric heat to gas heating, and relatively slow growth in overall number of customers. Data in this figure was compiled in December 2016.

Figure 32 shows the forecasted peak electrical demand for the service area, based on which regional demand forecasts and planning have been completed and as indicated the peak demand served from the distribution network is expected to decrease from the current levels. Data in this figure was compiled in September 2014.

Table 19 indicates the peak load during the most recent winter of January 2017 for each of the power transformers and as indicated the peak loads are well within equipment nameplate ratings and there are no capacity constraints in the system. Due to negative time trend in peak demand, no capacity constraints are anticipated during the next five-year period covered by this DSP. Data in this table was compiled in June 2017.

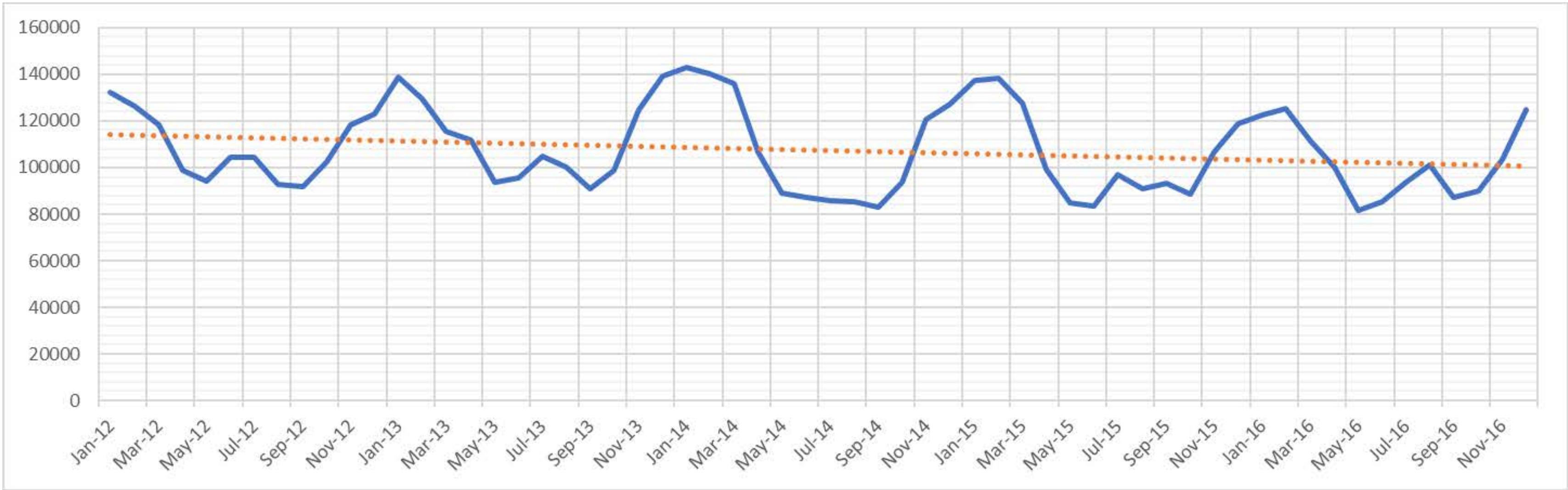
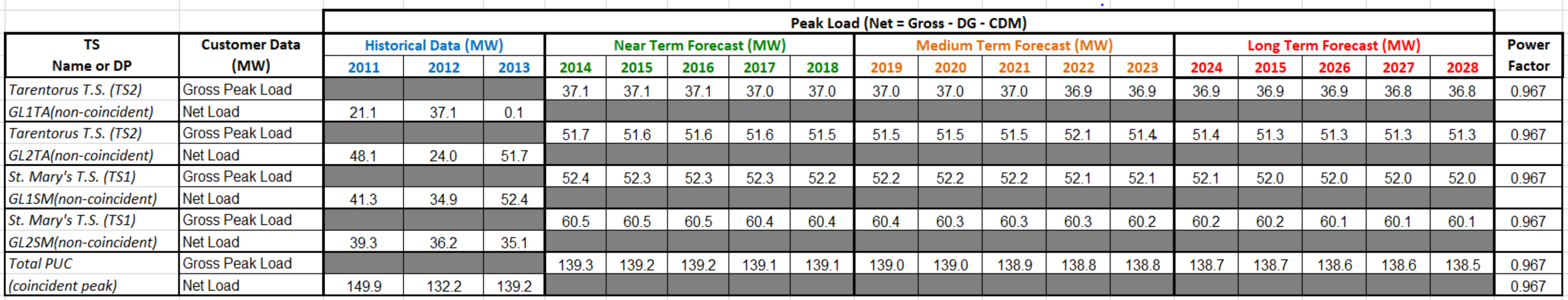


Figure 31: PUC Distribution Service Territory – Past Five Year System Loading



TS Name or DP	Customer Data (MW)	Peak Load (Net = Gross - DG - CDM)																		Power Factor
		Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)					Long Term Forecast (MW)					
		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2015	2026	2027	2028	
Tarentorus T.S. (TS2)	Gross Peak Load				37.1	37.1	37.1	37.0	37.0	37.0	37.0	37.0	36.9	36.9	36.9	36.9	36.9	36.8	36.8	0.967
GL1TA(non-coincident)	Net Load	21.1	37.1	0.1																
Tarentorus T.S. (TS2)	Gross Peak Load				51.7	51.6	51.6	51.6	51.5	51.5	51.5	51.5	52.1	51.4	51.4	51.3	51.3	51.3	51.3	0.967
GL2TA(non-coincident)	Net Load	48.1	24.0	51.7																
St. Mary's T.S. (TS1)	Gross Peak Load				52.4	52.3	52.3	52.3	52.2	52.2	52.2	52.2	52.1	52.1	52.1	52.0	52.0	52.0	52.0	0.967
GL1SM(non-coincident)	Net Load	41.3	34.9	52.4																
St. Mary's T.S. (TS1)	Gross Peak Load				60.5	60.5	60.5	60.4	60.4	60.4	60.3	60.3	60.3	60.2	60.2	60.2	60.1	60.1	60.1	0.967
GL2SM(non-coincident)	Net Load	39.3	36.2	35.1																
Total PUC	Gross Peak Load				139.3	139.2	139.2	139.1	139.1	139.0	139.0	138.9	138.8	138.8	138.7	138.7	138.6	138.6	138.5	0.967
(coincident peak)	Net Load	149.9	132.2	139.2																0.967

Figure 32: PUC Distribution Service Territory – Peak Demand Forecast

Table 19: 34.5kV/12.5 kV Substation Ratings and Loading Level

Station #	Transformer #	Transformer MVA	Peak Load MVA	% Transformer Loading
TS-1	T1	30	16.33	54%
	T2	30	16.61	55%
	T3	30	19.22	64%
	T4	30	19.52	65%
TS-2	T1	30	19.73	66%
	T2	30	19.91	66%
	T3	30	14.03	47%
	T4	30	14.27	48%

Station #	Transformer #	Transformer MVA	Peak Load MVA	% Transformer Loading
Sub 1	T1	10	4.85	49%
	T2	10	3.68	37%
Sub 2	T3	10	7.31	73%
	T4	10	2.18	22%
Sub 4	T1	10	4.15	42%
	T2 (4kV)	10	1.68	17%
Sub 5	T1 (4kV)	5	0.05	1%
	T2 (4kV)	5	0.05	1%
Sub 10	T1	13.3	3.87	29%
	T2	13.3	4.74	36%
Sub 11	T1	10	4.64	46%
	T2	10	4.00	40%
Sub 12	T1	10	4.29	43%
	T2	10	4.94	49%
Sub 13	T1	10	5.76	58%
	T2	10	4.74	47%
Sub 14	T1	3	0.08	3%
	T2	3	0.08	3%
	T3	3	0.08	3%
Sub 15	T1	10	1.82	18%
	T2	10	2.95	30%
Sub 16	T1	7.5	6.57	88%
	T2	7.5	4.14	55%
Sub 18	T1	7.5	4.91	65%
	T2	7.5	5.01	67%
Sub 19	T1	10	2.57	26%
	T2	10	8.82	88%
Sub 20	T1	10	3.33	33%
	T2	10	6.45	65%
Sub 21	T1	10	4.91	49%
	T2	10	4.69	47%

3.3 Asset Lifecycle Optimization Policies and Practices [5.3.3]

In preparing the DSP, PUC Distribution's overarching objective was to develop a capital and preventative maintenance investment plan, which would result in optimal operating performance to meet various stakeholder needs and ensure regulatory compliance, while minimizing life cycle costs, as shown in Figure 33.

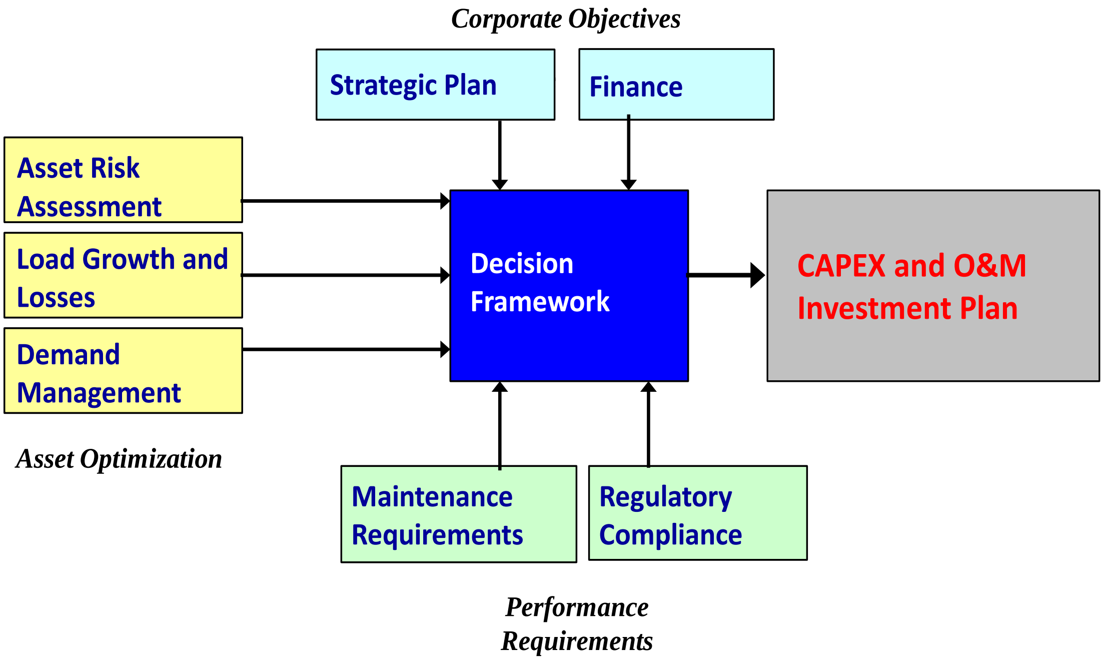


Figure 33: Multi-Prong Decision Framework

The life cycle optimization policies and procedures employed by PUC Distribution include determining the optimal time and scope of the most effective risk mitigation option, through trade-offs between capital expenditure, preventative maintenance and reactive maintenance. Figure 34 shows the basic decision support model employed by PUC Distribution in preparing this distribution plan, to determine the scope and timing of the investments. With increase in an asset's service age, its operating condition degrades, thus increasing the risk of the asset failing in service. In the absence of any intervention in form of asset renewal or asset refurbishment or repair, the consequential risk cost would continue to increase. When a risk mitigation intervention is implemented through an investment, the risk cost curve resets, triggering a benefit in form of reduced risk. In preparing the DSP, the timing and size of investments have been selected to minimize the "Total Cost" of the risk and the risk mitigation initiatives.

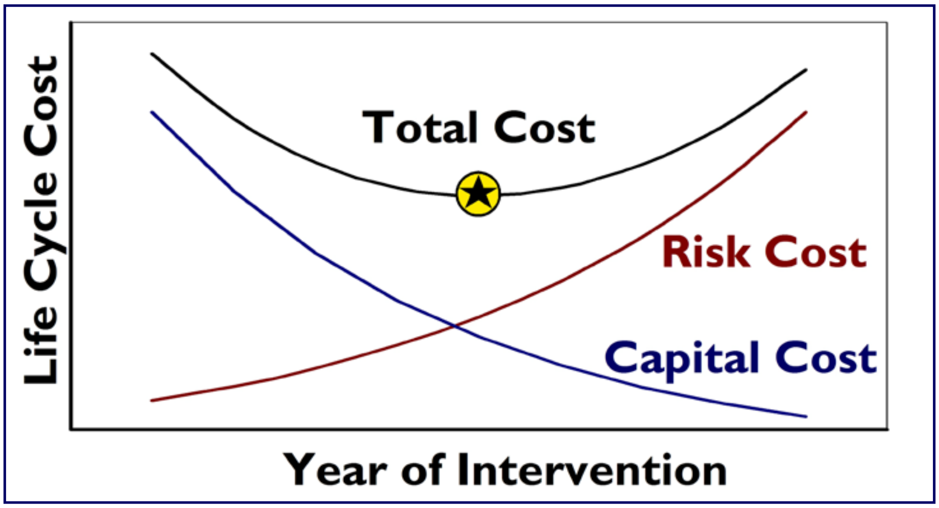


Figure 34: Risk Based Decision Support System

Figure 35 illustrates the impact of maintenance activities in extending the service life of an asset.[1] In Figure 35, Maintenance Policy 1 represents a reactive maintenance policy, in which no planned maintenance is carried out and asset components are repaired or refurbished only after they break down or reach a stage that they fail to perform their intended functions. Maintenance Policy 2 represents, proactive asset maintenance, in which condition of an asset's components are assessed periodically through inspections, testing and recent asset performance and maintenance activities are proactively performed to prevent impairment in asset performance with the intent of extending the economic service life of assets. Under Maintenance Policy 2, Optimization is carried out with the objective of minimizing overall life cycle costs of electricity distribution assets, while meeting the required performance levels, by taking into account all available information relevant to the condition of assets. As shown in Figure 35, Maintenance Policy 2 would be economically efficient, so long as the incremental asset value achieved through an assets' life extension is greater than the incremental maintenance cost resulting from Policy 2.

Following this value concept, PUC Distribution's maintenance planning criteria is rooted in adopting a maintenance policy that results in lowest life cycle cost for assets. For those assets, where the incremental value obtained in form of extended asset life is greater than the cost of maintenance activities, Policy 2 is adopted. These assets include high value power equipment installed in stations. Periodic inspections at more frequent intervals are performed and

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[1] "Predicting Future Asset Condition Based on Current Health Index and Maintenance Level" Thor Hjartarson, Shawn Otal, IEEE 11th International Conference on Transmission & Distribution Construction, Operation and Live-Line Maintenance, 2006, ESMO, Oct. 20

maintenance activities are scheduled by taking into account the condition of assets. For lower value assets, maintenance activities are performed in a reactive mode and the scope of repairs is limited to rectifying deficiencies found during safety inspections. Periodic asset inspections and testing provide valuable information on assets' health and probability of assets' failures, allowing appropriate risk management initiatives to be implemented over the lifecycle of each asset.

As an example PUC Distribution has employed this model as follows for in-situ testing of wood poles. All poles are tested and inspected on a seven year cycle. Poles that are determined to be in acceptable condition are deemed satisfactory until the next test cycle. Poles that exhibit significant deterioration but are still structurally sound are treated or maintained using boron rods to extend their service life. Poles that are more significantly deteriorated are scheduled for replacement.

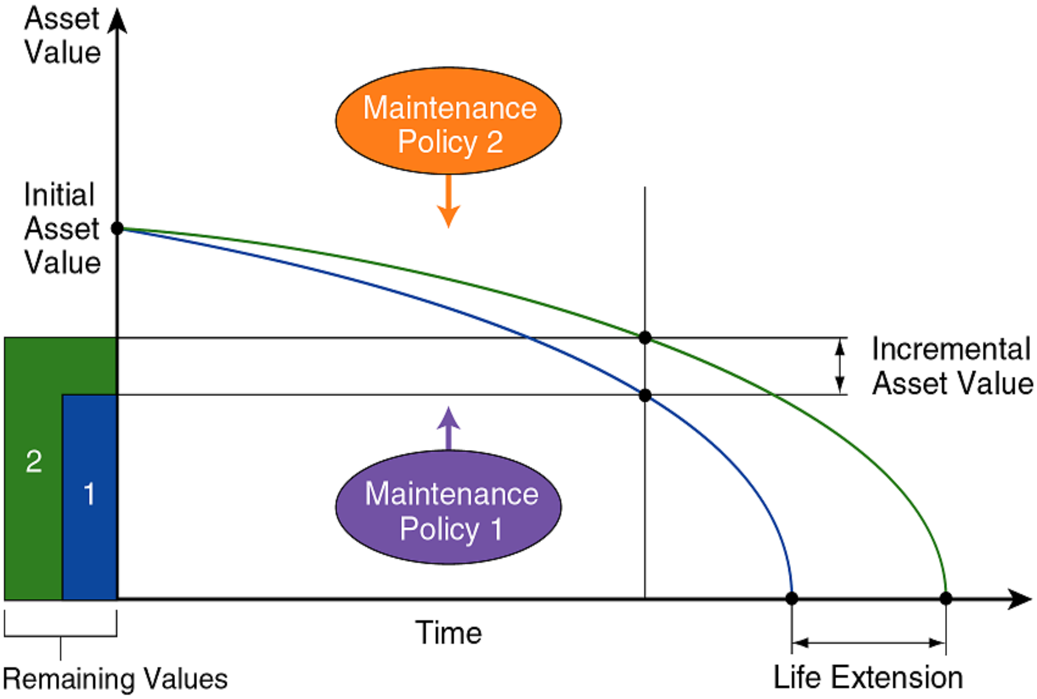


Figure 35: Risk Based Decision Support System

PUC Distribution's Operations & Maintenance ("O&M") programs are designed to follow the guidelines set out in the OEB's Appendix-C DSC for the inspection and maintenance of all key distribution system assets. PUC Distribution reviews its O&M programs annually in order to best align with our capital programs and aligning the program with the best industry practices and standards. Inspection and testing of assets is critical for the prioritization of operations and maintenance spending and optimization of the total life cycle asset cost. The results of inspections and testing are used to identify and prioritize system rehabilitation projects, resulting in selection of the optimal decision to either replace, repair or do-nothing. Assets for which replacement is identified as the optimal solution are included in the capital plan for replacement. For assets where replacement during the next five years is not determined to be the optimal solution, PUC Distribution's O&M programs include minor repairs and maintenance work designed to economically extend the life of assets. In both cases, planned replacement projects and planned operations and maintenance activities are selected in order to align with the budget envelopes by optimizing the scope and timing of work during project prioritization and selection processes.

PUC Distribution employs the results of visual inspections, in-situ testing and service age of assets to determine the condition of assets by deriving a health index for each asset. The health index is related to the probability of failure for the asset by relating the health of the asset to an effective age and corresponding known failure curve. The probability of failure data is multiplied by the consequences of failure for assets within a project area to arrive at a risk score. Consequences of failure are derived from the analysis of each project area and classification in terms of potential impacts to worker and public safety, the environment, reliability and operational effectiveness that could arise if a failure event occurs. Once the risk of each project area has been established it is placed into a prioritization and selection process that determines which projects require action and the extent of the action that is necessary to minimize unacceptable risks.

Risk is factored into the selection and prioritization of capital expenditures during the prioritization process. Assets with unacceptably high risk scores are monitored closely and plans are included in project scope to alternatively maintain, refurbish or replace the assets to reduce the risk to an acceptable level. It is noteworthy that some assets carry an inherently higher risk than others, for example, power transformers at stations have a higher nominal risk level associated with them in relation to pole mount transformers. Assets with low health indices and higher consequence risk are given a priority for replacement, while assets with low health indices but lower consequence risk are given a lower priority for replacement. The top projects in each category are identified in the prioritization process and scrutinized using further investigation and expert opinion to eliminate data inconsistencies and determine appropriate scopes of work.

3.3.1 Preventative Maintenance and Safety Inspections

Proper maintenance is essential to prolong asset lifecycles and maintain system reliability. PUC Distribution's maintenance program employs equipment manufacturer's recommendations as well as best industry practices in determining the scope and frequency of maintenance on power equipment. Maintenance programs comply with all regulated requirements as prescribed in the Distribution System Code. In distribution and transformer stations, where applicable, maintenance also meets IESO and NERC requirements and is completed in accordance with associated elements from the Transmission System Code and best practice IEEE guidelines. Many new requirements have been introduced due to the recent implementation of an IESO mandated under-frequency load shedding (UFLS) scheme.

3.3.1.1 Preventative Maintenance of Critical Equipment in Substations

PUC Distribution's planned substation maintenance schedule is summarized in Table 20.

Table 20: Substation Preventative Maintenance

	Visual Inspection of Assets	**Testing of Insulating Oil Samples, and Infrared Scanning**	**DC System Maintenance**	**Full Off-line Substation Maintenance (Annual Cycle Tests)**
Distribution Stations	Monthly	Annually	Quarterly	Once in six years
Transformer Stations	Weekly	Annually	Quarterly	Once in four years

Monthly inspections at distribution substations and weekly inspections at transformer stations include the following tasks;

- Inspect substation security (gates locked, fence condition, warning signs and emergency contact information posted).
- Inspect substation yard and building condition, including vegetation growth, snow bank accumulation, garbage, vandalism, etc.
- Inspect substation electrical safety, including fence grounds, bonds, equipment grounds, insulators, foundations, ancillary equipment, metal clad fastenings and corrosion related impairment of assets
- Power Transformer Inspections, including checking and recording oil level, oil temperature, equipment grounds, feeder load readings (Amps)
- Inspect Access and Egress Riser Poles
- Verify AC voltage to Battery Banks
- Inspect Batteries

- Inspect and record Relay Voltage, Amps etc.

The annual cycle maintenance of substation equipment includes thorough inspection, testing and maintenance of all power equipment installed at substations. The substation is taken out of service typically for an extended period to perform maintenance. The station maintenance work includes;

- Oil Testing of Transformers (standard 5 part ASTM and DGA)
- Clean and lubricate switches and fusing
- Conduct Insulation Resistance Testing
- Protection Relays are injection tested to verify settings and ensure operating times adhere to the manufacturers specifications
- Clean and lubricate switchgear, ensure proper operation
- Conduct IR scans of all high voltage electrical equipment (insulators, switches, cables, connections and riser poles)
- Oil Testing of Transformers (standard 5 part ASTM and DGA)
- DC System batteries are maintained as per manufacturers specifications on a quarterly basis at all distribution and transformer stations

3.3.1.2 Vegetation Management Program

PUC Distribution's service territory is divided into 4 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 is managed according to our Utility Vegetation Management program on a 4-year cycle by attending to each section in succession on a yearly basis.

- Line clearing activities are predominantly completed via a contract that specifies removal of vegetation growth within 3m of primary conductors and 1.5m of secondary conductors. Identification and removal of danger trees, as well as brushing and herbicide treatment of right-of-way where appropriate are included to ensure a comprehensive program.
- Substation herbicide treatment (as required)

During 1/3 plant inspections PUC Distribution line crews sometimes identify dead or unstable trees that could impact public safety or system reliability. The identified "danger" trees are then removed by PUC Distribution line crews or facilitated during the contract period depending on urgency. Although danger tree and customer requested removals are predominantly completed within the scope of an outside contract, PUC Distribution line crews will also perform work to maintain safe clearances throughout the year in response to urgent safety or reliability issues or storm damage. All customer requests for tree related issues are tracked as Customer Service Orders through the Customer Information System.

3.3.1.3 Safety Inspections of Overhead and Underground Distribution Assets

PUC Distribution lines and underground distribution system plant are inspected on a 3-year cycle, to comply with the Distribution System Code requirements. One third of the distribution assets employed on PUC Distribution's supply network are inspected each year. Structural defects, clearance issues and electrical problems and hazards are identified through visual inspections and where problems are revealed, either repair work is scheduled or capital work is planned, as needed. Where the inspections determine an immediate hazard to the public, immediate follow up action is taken to mitigate the problem.

4 Detailed Capital Investment Plan [5.4]

This section summarizes PUC Distribution’s capital expenditure plan, which has been developed to meet PUC Distribution’s strategic corporate objectives. The capital expenditure plan was developed based on the outputs of the risk-based asset management process, described in detail in Section 3 Projects have been divided into the four categories as outlined in the OEB Filing Requirements.

4.1 Key Information about Capital Expenditure Plan [5.4.1]

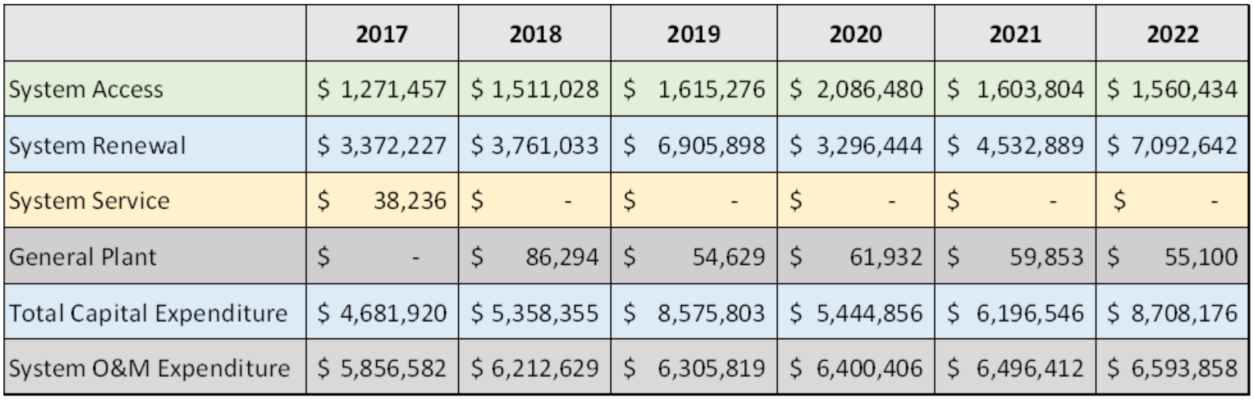
4.1.1 Distribution System Capability to Connect New Load or Generation [5.4.1a]

As previously described in Section 3.2, PUC Distribution’s distribution system has adequate capacity to connect all anticipated loads and generation customers during the next five-year period, covered by this DSP. Currently there are no applications in queue from distributed generation customers waiting to be connected to the grid under any IESO REG programs; and all previous requests received to date have been successfully connected to the system.

4.1.2 Summary of Annual Capital Expenditures by Investment Category [5.4.1b]

The capital investments (net of contributed capital) for the bridge year (2017) and the forecast period (2018 to 2022) are summarized in Table 21. Additional detailed information on the proposed capital projects exceeding the materiality threshold for projects in the test year (2018) is provided in Table 22 and Appendix G.

Table 21: Proposed Capital Investments during DSP Implementation Period



	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 Capital Expenditure	$ 4,681,920	$ 5,358,355	$ 8,575,803	$ 5,444,856	$ 6,196,546	$ 8,708,176
System O&M Expenditure	$ 5,856,582	$ 6,212,629	$ 6,305,819	$ 6,400,406	$ 6,496,412	$ 6,593,858

Table 21 shows the planned capital investments broken down into each of the four general categories: System Access, System Renewal, System Service, and General Plant.

The planned investments into System Access are intended to facilitate the anticipated growth and allow connection of new customers to the grid, meeting requests of existing customers for increase in service size, meeting PUC Distribution's regulatory obligations for relocating distribution lines when requested by the municipality, for joint use make-ready work for telecommunications and for re-calibration and renewal of the revenue meters in compliance with the Measurement Canada regulations. A modest recovery in the local economy is anticipated during the next five years, resulting in a small increase in requests for new services from the existing levels. There are presently two residential subdivision developments being planned for 2018 and 2019, and these will require capital investments in System Access category to meet the requests for new services. Road reconstruction projects undertaken in the municipality require relocation of some power distribution lines, requiring capital investments by PUC Distribution. PUC Distribution has employed the City's 5-year development plan to estimate capital expenditure required for line relocates and rebuilds to accommodate municipal infrastructure projects. The planned System Access investments include funding for residential revenue meters, required to replace meters failed in service as well as to equip all general service customers with >50kW to <500kW demand with MIST meters. The planned investments in this category also include funding for "make ready work" to allow joint sharing of the distribution facilities by the communication network companies. The indicated investments in the System Access category represent net expenditure by PUC Distribution, after third party contributions have been subtracted from the total cost.

The planned investments into System Renewal are intended to mitigate a number of specific prevailing risks to distribution system reliability, safety and adverse environmental impacts, due to very poor condition of some key assets, the in-service failure of which would lead to significant negative outcomes. As described in greater detail in Section 3.2.3, those assets, the condition of which has already reached a state of impairment that they present a very high risk of failure in service are assigned "very poor" condition and those assets with significant impairment causing performance to degrade below acceptable level and presenting a high risk of failure in service in the absence of major repair or rehabilitation or renewal, are assigned "poor condition". The scope of capital investments planned in the "System Renewal" category has been determined with the objective of keeping power supply reliability from deteriorating below the acceptable level, as indicated by SAIFI and SAIDI targets. In order to keep the overall investment envelope for this DSP within a range, which would not result in retail rates escalations beyond the affordability of PUC Distribution's customer base and which could be successfully implemented without stretching beyond limit PUC Distribution's financial resources; investments required for renewal and rehabilitation of the assets found in "very poor" or "poor" condition have been spread out over a time period of longer than five years and assets with highest consequence of failure in service, have been prioritized for renewal or rehabilitation, during the next five years.

Although no planned investments have been included in the System Service category, a number of investments in the renewal category, particularly those involving station rebuilds and voltage upgrade, will also introduce smart grid features including opportunities for greater automation, improved access for connection of renewable generation and improved access for joint-use of distribution facilities. Therefore, these investments can be considered to serve a dual role: System Renewal as well as System Service.

PUC Distribution leases its motor vehicle assets rather than owning them, therefore a relatively small capital investment is required for renewal of General Plant, needed to cover minor building renewal items. The scope and timing of the investments in each category has been determined by taking into account all information available at the time of preparation of the distribution plan.

The capital investments proposed for the 2018 to 2022 period are expected to yield the following benefits:

i. The investments into the System Access category would allow PUC Distribution to meet its obligations to serve new customers, relocate lines in public right-of-way, upon receipt of requests for such services, perform “make ready” work for allowing third party attachments of electricity distribution poles and to have adequate supply of revenue meters to comply with the requirements of the Distribution System Code and Measurement Canada.

ii. The investments into the System Renewal will reduce the risk of critical assets’ failure in service and help sustain the reliability at acceptable levels and ensure public safety. These investments will also help avoid an increase in operating costs by eliminating the increase in extent of emergency repairs upon asset failures. Retiring from service the distribution system infrastructure operating at 4 kV will eliminate duplication in spare part requirements and will result in improved operating efficiency.

iii. Investments in General Plant are aimed at improving worker productivity, operating efficiency and employee safety.

Planned investments into O&M are aimed at providing customer services matching the service quality and power supply reliability targets. These investments not only including funding for power restoration with adequate speed, following interruptions, but also include funding for safety inspections, tree trimming, equipment testing to prevent and reduce the incidents of power interruptions. O&M investments also including funding for preventative maintenance of high value assets to prevent asset impairment and ensure the assets don’t fail pre-maturely.

4.1.3 Capital Expenditure Relation to Asset Management Plan [5.4.1c]

The capital expenditure proposed in this DSP and summarized in Table 21 is in response to the following primary drivers:

- System Access;
- System Renewal;
- System Service; and
- General Plant Upgrades.

System Access Investments

System Access investments comprise about 24% of the proposed capital investments during the forecast period [Table 21]. The planned investments in the System Access category are required for PUC Distribution to meet its regulatory obligations inclusive of the Distribution System Code and PUC Distribution's Conditions of Service and are, therefore, mandatory expenditures. Planned investments in this category are included to connect new generation and load customers, permit service upgrades requested by customers, allow line relocates in response to requests from municipalities, support joint-use installations by third party communications parties and fund investments into revenue metering. Planned expenditure into System Access in 2020 is markedly greater than the rest of the years to allow for the needed investments to facilitate calibration and replacement of revenue meters and equipping customers with a demand greater than 50kW with meters capable of supporting 'Metering Inside the Settlement Timeframe' (MIST) to comply with the recent changes in regulatory requirements. PUC Distribution has considered a number of factors from their asset management and capital expenditure process to determine the allocation of investment in System Access:

- Consultation with major stakeholders including customers, municipal governments, CDM program partners and the OPA/IESO. These consultations allowed PUC to coordinate infrastructure planning with the City of Sault Ste. Marie and identify investment level requirements required to support projects for subdivisions, joint use and general services.
- Consultation with existing customers both residential and general service, through formal and informal community engagement activities. The reports from these consultations inform the PUC's understanding of current and future electrical needs and helps PUC plan the system accordingly in support of System Access investments.

Due to the fact that planned investments in the System Access category are mandatory, the full annual estimated expenditures have been included. Investments in the remaining three categories (System Renewal, System Service and General Plant) have been prioritized utilizing the asset management strategy described in Section 3 and have been allocated the balance of available capital funds premised on the available financial envelope.

System Renewal Investments

System Renewal investments contribute the largest portion, at 75%, of the proposed capital investment budget Table 21. Planned investments into System Renewal are based on reducing the risk associated with asset failures to optimal levels, based on the results of asset condition assessment which is included in Appendix B. The asset health information is also one of the inputs for the prioritization process described in Section 3.1.2 Consultations with existing customers and the resulting information about customer preference is taken into account to ensure that only the projects with the highest risk of failure in the next five years are included in the System Renewal plan. While, optimal risk considerations required the System Renewal investments to be greater than the planned amount indicated in Table 21, the investment level in this category was reduced from the optimal amount to keep retail rate escalation from reaching an unacceptable level. Furthermore as indicated in Table 22 forced overhead and underground renewal are mandatory for the purpose of restoring service to customers. Investments into System Renewal during 2019 and 2022 are significantly greater than the rest of the years because they includes investments for a distribution station rebuild during each of these years.

System Service Investments

Although no planned investments have been included in the System Service category, a number of investments in the renewal category, particularly those involving station rebuilds and voltage upgrades, will also introduce smart grid features including opportunities for greater automation, improved access for connection of renewable generation and improved access for joint-use of distribution facilities. Therefore, these investments can be considered to serve a dual role: System Renewal as well as System Service.

General Plant

General Plant makes up only about 1% of the proposed capital investment budget. PUC Distribution leases its motor vehicle assets rather than owning them, therefore a relatively small capital investment is required for renewal of General Plant, needed to cover equipment and minor building renewal items.

4.1.4 Material Capital Expenditure Projects/Activities [5.4.1d]

Proposed investments during the test year into individually identifiable projects, exceeding the materiality threshold for PUC Distribution are summarized in Table 22. The table also provides an indication of the spending level by category (System Access, System Renewal) for projects above the materiality threshold in relation to the total spending, including projects above and below the materiality threshold.

Priority rankings for each of the projects above the threshold of materiality have been determined using a two-step process. Firstly, utilizing the methodology presented in Section 3.1.2., a shortlist of the most critical projects was determined for the test year. This shortlist of projects was then ranked by applying a second set of refinement criteria also aligned with the same methodology. The refinement criteria and the relative weighting of each is identified below;

- **Public safety** (40%) - safety risks and consequences of equipment failure
- **Customer outage impact** (10%) - quantity of customers affected and duration of outage
- **Customer value per dollar** (15%) - quantity of customers affected as a function of total project cost
- **System Service improvements** (10%) - projects exhibit value in supporting the OEB System Service category as a secondary driver to System Renewal e.g.: station upgrades will support the connection of REG through new protective equipment upgrades
- **Project interdependence** (25%) - projects that, if not completed, would negatively impact the ability to complete future planned projects

System Access investments are a regulatory obligation for distribution companies (as defined in the Distribution System Code and PUC Distribution's Conditions of Service) and therefore the first four projects in Table 22 in the System Access category, received the highest priority in the overall investment envelope. System Renewal is the primary driver for the next 9 projects planned to be implemented during the test year. Out of these the first two projects involve renewal of assets in a reactive mode, e.g. replacing a distribution transformer or underground cable etc. after an asset has failed in service, in order to restore power. These projects also received the highest priority score, because their implementation is mandated in order for PUC Distribution to fulfill its regulatory obligations to supply electricity to all customers connected to the grid. The next seven projects, listed in order of priority, involve proactive asset renewal to prevent failure of critical assets in service.

As described in detail, in Section 4.1.8, all of the material System Renewal projects in Table 22 re in response to customer preference. Of those customers willing to consider additional costs the highest preference was towards replacement of aging equipment to maintain or improve reliability. Therefore, the focus of the investments proposed in this DSP is to preserve the existing supply security and reliability levels and prevent them from degrading. In addition, the Substation 16 rebuilt project takes advantage of technology based solutions to improve operational efficiency and potential to integrate additional distributed generation and complex loads. Detailed descriptions for each of these projects exceeding the threshold of materiality are provided in Appendix G.

Table 22: Proposed Capital Investments during Test Year - Projects over Materiality Threshold

Category	#	Project Code	Project Description	Priority Ranking	Planned Expenditure in 2018
System Access	1	1C100-1	Customer Demand - Services	1	$ 912,047
	2	1C100-2	Customer Demand - New Subdivisions	1	$ 107,153
	3	1C100-3	Customer Demand - Joint Use	1	$ 97,153
	4	1C100-4	Customer Demand - City Projects	1	$ 224,305
			Total (Material Projects Only)	-	$ 1,340,658
			Grand Total (Material and Non-material)	-	$ 1,511,028
System Renewal	5	1C200-1-1	Forced Overhead Renewal	1	$ 252,343
	6	1C200-1-2	Forced Underground Renewal	1	$ 308,593
	7	1C300-3-7 - A	Substation 16 Rebuild	2	$ 419,687
	8	1C300-1-2	Overhead Renewal - Poles	3	$ 314,765
	9	(2018) 1C300-1-4C	Overhead Renewal - Restricted Wire (Wallace Terr., 2nd, 5th, 6th Ave., Devon Rd. & Woodcroft Ave.)	4	$ 433,676
	10	(2018) 1C300-2-4	Underground Renewal - Voltage Conversion (Laronde Ave., Koprash Crt.)	5	$ 531,603
	11	(2018) 1C300-1-4B	Overhead Renewal - Restricted Wire (Red Pine Drive - North of Pnt. Of Pins)	6	$ 349,739
	12	(2018) 1C300-1-3A	Overhead Renewal - Voltage Conversion (MacDonald Ave - Lake St. to Moluch St.)	7	$ 288,020
	13	(2018) 1C300-1-4A	Overhead Renewal - Restricted Wire (Carpin Beach Rd - Base Line to Herkimer, Phase 1 of 2)	8	$ 185,155
			Total (Material Projects Only)	-	$ 3,083,581
			Grand Total (Material and Non-material)	-	$ 3,761,033
Total Expenditure on Material Projects During Test Year					**$ 4,424,239**
Total Expenditure on Capital During Test Year (System Access, System Renewal, System Service and General Plant Inclusive)					**$ 5,358,355**

The project prioritization criteria along with scoring to determine project priority rankings are shown in Table 23. Some details as to how the specific projects for the test year were scored are as follows:

Sub 16 Rebuild – Phase II of III

Other than safety, all of the remaining criteria contributed significantly to making this the highest priority planned project. This station serves approximately 2400 customers therefore outage impacts, and customer value for dollar received corresponding high ratings. This project also brings value in the form of improved System Service; protective relays and communications technology will allow for the future connection of REG and smart grid opportunities.

Deteriorated Poles

The predominant criteria that served to rank deteriorated poles as the second highest priority project was public safety due to the potential failure mode of this asset class.

Restricted Wire Projects

Three restricted wire projects were identified in the test year above the materiality threshold. They are ranked fourth, sixth and eighth in terms of overall priority. Public safety impact is the predominant driver. The differentiator between projects in this category is premised on number of customers impacted by each project and the corresponding value for money.

Voltage Conversion

There are two voltage conversion projects selected for construction in 2018 that are ranked fifth and seventh. Project interdependence was the primary criteria that impacted the scoring. These projects need to proceed to allow the retirement of two end-of-life 4.16kV substations (Substations 4 and 5). These and are planned for removal from service during the latter part of the 2018-2022 rate application period.

Table 23: Prioritizing Matrix for Test Year Projects over Materiality Threshold

Rank	Primary Factor[10]	Area	Program	Project	Public Safety Impact				Outage Customer Impact				Customer Value for $				System Service Improvements				Project Interdependance				Score
					Weight			40.0%	Weight			10.0%	Weight			15.0%	Weight			10.0%	Weight			25.0%	
					R	C	PSI	PSI (n)	QTY	HRS	COI	COI (n)	$K	C	CV	CV (n)	QTY	SIV	SSI	SSI (n)	SQI	FI	PI	PI (n)	
1	Customer Preference	System Access	N/A	N/A	Ranked as first priority as these are non discretionary																				N/A
1	Customer Preference	Forced Renewal (System Renewal)	N/A	N/A																					N/A
2	Customer Preference, Technology Based	Planned Projects & Programs (System Renewal)	DX Stations	Sub 16 Rebuild - Phase II of III	2	5	10	1.0%	2417	3	7251	8.3%	420	2417	5.8	10.5%	2417	5	12085	9.5%	5	10	50.0	7.4%	36.7%
3	Customer Preference	Planned Projects & Programs (System Renewal)	OH Renewal	Poles - Det. Poles	10	10	100	9.7%	160	1.5	240	0.3%	210	160	0.8	1.4%	160	1	160	0.1%	1	5	5.0	0.7%	12.2%
4	Customer Preference	Planned Projects & Programs (System Renewal)	OH Renewal	Rest. Wire - Wallace Terrace/2nd Ave./5th Ave./6th Ave./Devon Rd./Woodcroft Ave.	7.5	10	75	7.3%	254	3	762	0.9%	442	254	0.6	1.0%	254	1	254	0.2%	5	1	5.0	0.7%	10.1%
5	Customer Preference	Planned Projects & Programs (System Renewal)	UG Renewal	Volt. Conv. - Laronde/Koprash	1	1	1	0.1%	79	1.5	119	0.1%	542	79	0.1	0.3%	79	1	79	0.1%	5	10	50.0	7.4%	8.0%
6	Customer Preference	Planned Projects & Programs (System Renewal)	OH Renewal	Rest. Wire - Red Pine Dr. (N of Pnt of Pins)	7.5	10	75	7.3%	32	3	96	0.1%	357	32	0.1	0.2%	32	1	32	0.0%	3	1	2.5	0.4%	8.0%
7	Customer Preference	Planned Projects & Programs (System Renewal)	OH Renewal	Volt. Conv. - MacDonald (Lake to Moluch)	1	1	1	0.1%	26	1.5	39	0.0%	294	26	0.1	0.2%	26	1	26	0.0%	5	10	50.0	7.4%	7.7%
8	Customer Preference	Planned Projects & Programs (System Renewal)	OH Renewal	Rest. Wire - Carpin Beach Rd. (Base Line to Herkimer) PH 1 of 2	5	10	50	4.9%	12	6	72	0.1%	189	12	0.1	0.1%	12	1	12	0.0%	1	1	1.0	0.1%	5.2%

Notes Regarding Ranking Methodology

1) Public Safety Impact (PSI) due to failure = Risk (R) x Consequence (C) where (R = (1 = low, 10 = high)= - 1, C = (1 = low, 10 = high)
2) Customer Outage Impact (COI) = (Qty Customers Affected (QTY) x anticipated outage hours/year (HRS))
3) Customer Value (CV) = Cutomers Served (C) / $100,000($K)
4) System Service Improvements (SSI) = Qty Customers Affected (QTY) x Service Improvement/Enhancement Value (SIV) factor, (1 = low, 5 med, 10 = high)
5) Project Interdependence (PI) = Impact of a project not proceeding negatively impacting the ability to complete other future planned work = (SQI = service quality impact x FI = financial impact), values (1 = low, 10 = high)
6) Score = Sum of five factors above (Public Safety, Outage Customer Impact, Customer Value after weighting each equally (ie: 20%) allowing for a maximum atainable score of 100%
7) (n) represents a normalized score where for the ranked projects, each is normalized to a scale of 0%-20%
8) Rank is determined by placing Scores for all planned capital projects in a rank ordered list. A rank of 1 represents the highest priority. Non-discretionary customer demand work and capital work driven by unplanned repairs have all been weighted equally and assigned a Rank of 1
9) It is noted that the projects within this matrix are those previously screened through the Asset Management Plan process and they therefore represent only the most critical projects identified and prioritized throug that process
10) Primary Factor categories include (a) Customer Preference, (b) Technology Based and (c) Innovative Process

4.1.5 Impact of Regional Planning Process [5.4.1e]

The regional planning process identified no system constraints in the upstream system and has no impact on the investments proposed in this DSP.

4.1.6 Impact of Customer Engagement Activities on DSP [5.4.1f]

As described in Section 2.1.1, during customer engagement sessions, a vast majority of PUC Distribution's customers have generally indicated satisfaction with the current reliability and service quality levels. Even so, it was also identified that the customer priority and preferences were directed at improving reliability, better communications and consultations (including related to outages and projects) and a managed approach to infrastructure renewal (replace before failure respecting safety and large reliability impacts). Customer surveys also indicated sensitivities towards rising electricity prices and indicated preference to lower electricity rates. Of those customers willing to accept additional costs, the highest preference was towards replacement of aging equipment to maintain or improve reliability and lower preference to smart grid features allowing customers opportunities to manage their electricity use.

In view of this feedback, this DSP has been prepared to keep the retail rate escalations at a modest level, by accepting a greater level of risk of asset failures in service where impacts can be mitigated through spares and alternative supply. In view of the customer sensitivities to rising electricity prices, only a subset of the assets determined to be in "poor" or "very poor" condition have been prioritized and included in this DSP for renewal or refurbishment. Because the peak demand in this service territory is expected to decrease rather than increase, no investments are proposed in this DSP for capacity upgrades or smart grid features allowing customers greater access to control their electricity use or curtail peak demand.

Based on customer feedback, the focus of this DSP has been on the need to prudently plan investments to maintain utility operations at optimal level.

4.1.7 Distribution system development [5.4.1g]

Because no capacity constraints currently exist in the distribution system and none are expected to arise during the next five years for connecting load or generation customers, no investments are proposed into system capacity upgrades. There are presently no applications in queue for REG connections. There is adequate capacity in the system to accept all projected generation connection requests for the coming 5 years.

4.1.8 Distribution system development [5.4.1h]

As described previously in Section 2.1.1, during customer engagement sessions, a vast majority of PUC Distribution's customers have indicted satisfaction with the current reliability and customer service levels. Customer surveys also indicated sensitivities towards rising electricity prices and indicated preference to lower electricity rates. Of those customers willing to consider additional costs the highest preference was towards replacement of aging equipment to maintain or improve reliability. Therefore, the focus of the investments proposed in this DSP is to preserve the existing supply security and reliability levels and prevent them from degrading. Project budgets also reflect the increased emphasis on communications and engagement with customers throughout the project cycle from planning through execution to closure.

PUC Distribution has implemented tools to address customer preferences with respect to data access and visibility. For example, the Customer Connect software application implemented in conjunction with the introduction of smart meters allows customers visibility into their consumption usage on a daily and hourly basis.

Keeping in view the customer's preference for low electricity prices, no investments are proposed in this DSP for smart grid initiatives or pilot projects to provide additional data access and visibility from the current level at this time. As mentioned earlier, PUC Distribution's distribution system already has adequate capacity to accept distributed generation customers and PUC Distribution is proactively participating in the province's CDM program for load management. Because the peak demand in the region has been decreasing and this trend is expected to continue, investments into technology to reduce peak demand would yield low benefits in this service territory. PUC Distribution is already employing technology-based opportunities to improve operational efficiency, asset management and the integration of distributed generation and complex loads and no additional investments are considered necessary in this area.

Sault Smart Grid Project

PUC Distribution has been exploring an innovative and large scale system smart grid project for a few years that could provide significant benefit to our customers. The project would include elements for distribution automation, voltage control and improved customer care and outage management capabilities. The project conceptually has included a "no net bill increase" hurdle for customers as a primary evaluation criteria recognizing the high concern for customers on current costs for electricity. To meet this hurdle a significant level of financial support is being sought and will be needed for internal project approval. It is anticipated that PUC Distribution would be utilizing the Incremental Capital Module process for this project should the analysis and financial feasibility criteria, including the "no net bill increase" be achieved. Should the project funding applications be approved and OEB approval attained, and subject to final PUC Board of Directors approval this 2 to 3 year project would represent a substantial advancement in smart grid technologies being implemented by PUC Distribution.

4.2 Capital Expenditure Planning Process Overview [5.4.2]

For reference, the capital expenditure for projects above the materiality threshold in the test year are shown in Table 22.

4.2.1 Planning Objective, Criteria and Assumptions [5.4.2 a]

The capital expenditure plan proposed in this DSP has been developed by ensuring that the DSP objectives are aligned with its corporate goals, using the feedback from customer engagement sessions, conclusions of the asset management plan and the regional grid planning as an input, which allowed alignment of the overall corporate vision, mission statement and values with the proposed investment plan.

PUC Distribution's investment planning objectives into each investment categories are listed below:

1) Ensure appropriate level of investment allocation to meet the regulatory obligations of the System Access such as metering, system relocations for municipal road work, future system requirements for residential, commercial and industrial load customers as well as generation customers and joint-use customer requests. ;
2) Ensure adequate level of objectively prioritized investments into distribution System Renewal to maintain optimal risk levels related to asset failures in service, particularly those impacting safety, reliability and environment, as determined through the continued condition assessment of assets;
3) Ensure the acceptable level of expenditures required to maintain sufficient system capacity to meet existing and future capacity demand levels, including adequate capacity to allow connection of renewable generation;
4) Ensure proper allocation of investments into General Plant assets to maintain employee safety and productivity.
5) Review overall expenditures to ensure retail rate impacts and adjust spending as required to ensure retail rates remain affordable.

Because the distribution system has adequate capacity to allow connection of anticipated load and generation customers, no REG investments are proposed for system capacity upgrades to accept new generation or load customers. Because there are no capacity related system constraints and no investments are required to mitigate capacity constraints, use of non-distribution system alternatives to relieve system capacity or operational constraints is not necessary. The Regional Planning Process has been completed and it did not identify any issues requiring any investments by PUC Distribution. A copy of the Regional Infrastructure Planning Report is included in Appendix E. Also, because customers have indicated preference for lower electricity prices no investments are proposed in this DSP for smart grid initiatives or pilot projects to provide additional data access and visibility from the current level. As mentioned earlier, PUC Distribution is proactively participating in the province’s CDM program for load management.

PUC Distribution has determined that there are a number of important inputs required in order to support investment decisions to ensure the investment level is appropriate and is targeted into the appropriate area. As such, planning criteria inputs are utilized to support investments into each of the four categories, as indicated below:

- Consultation with municipal officials to understand future projects requiring relocation of distribution lines in support of System Access investments;
- Incorporating customer growth forecasting into capital expenditures for anticipated residential and commercial developments in support of System Access investments;
- Ongoing dialogues and open communications between large load general service customers and PUC Engineering department to gain perspective on any changes in their electrical demand in support of System Access investments;
- Asset Condition Assessments to support expenditures related to asset renewal to maintain the system as designed in support of System Renewal investments;
- System capacity assessments to identify requirements for System Service investments; and
- Individual assessments on key areas in General Plant such as buildings and facilities required to support expenditures in General Plant.

The investment requirements to facilitate new customer connections, service upgrades, joint use requests and line relocates in response to municipal requests are difficult to predict accurately, so the expenditure requirements in these categories have been estimated based on knowledge of past expenditures and knowledge gained through stakeholder engagement.

The overarching objective of PUC Distribution’s asset management plan is to identify and implement the optimal time and scope of investments into asset maintenance, refurbishment and replacement. Each of the asset management objectives described in Section 3.1 are considered during prioritization of the investments into System Renewal, with appropriate weights assigned to each objective, as indicated. A prioritized list of the projects above the materiality threshold and planned to be implemented during the test year is provided in Table 22.

4.2.2 Policy for Relieving System Capacity and Operational Constraints [5.4.2 b]:

Because the distribution system has adequate capacity to allow connection of anticipated load and generation customers, no REG investments are proposed for system capacity upgrades to accept new generation or load customers.

The peak system demand is expected to decrease and not increase. Because there are no capacity related system constraints and no investments are required to mitigate capacity constraints, use of non-distribution system alternatives to relieving system capacity or operational constraints is not necessary. The Regional Planning Process has been completed and it did not identify any issues requiring any investments by PUC Distribution.

Also, because customers have indicated preference for lower electricity prices no investments are proposed in this DSP for smart grid initiatives or pilot projects to provide additional data access and visibility from the current level. As mentioned earlier, PUC Distribution is proactively participating in the province's CDM program for load management.

4.2.3 Processes, Tools and Methods to Select, Prioritize and Pace Projects [5.4.2 c]:

Please refer to Section 3.1.1 and 3.1.2, where processes, tools and methods used to select, prioritize and pace different categories of investments are described in greater detail. In addition reference to Appendix H will provide detail of mechanisms used to engage customers in identifying their needs, priorities and preferences and the relationship to the projects listed for the DSP test year where applicable.

A brief summary of the processes, tools and methods used to identify, select, prioritize and pace projects in each investment category is provided below:

4.2.3.1 System Access

Identification

Projects are identified through contact with customers wishing to connect new services, service upgrades, requests from municipal landowners to relocate assets to accommodate road reconstruction or requests for services from joint use communication companies. As described in greater detail in Section 2.2.1.1, Appendix C and Appendix H, customer engagement sessions have generally indicated high customer satisfaction for delivery of services under System Access category and therefore no changes are considered necessary to the existing processes.

Selection

Investments into System Access projects are non-discretionary in nature and are required to fulfil PUC Distribution's regulatory obligations and projects in this category.

Prioritization

Given that these projects are mandatory, they are therefore given the highest priority for implementation. Project prioritization is based on the expected date when all service requirements are fulfilled by the customer and consideration of the customer's schedule for implementation, as identified through regular contact between both parties.

Pacing

For new service additions or service upgrades, projects are planned and executed to ensure that low voltage connections are completed within 5 days of the fulfillment of all service conditions and high voltage services are connected within 10 days of the fulfillment of all service conditions. In the case of make-ready work for communication company applications, pacing is premised on the terms and conditions of joint-use agreements as well as ongoing consultations. Road reconstruction projects are paced through close coordination with the City planning and engineering departments and in accordance with the associated project schedules.

4.2.3.2 System Renewal

PUC Distribution identifies asset repair, refurbishment and replacement requirements through asset condition assessment as described in more detail in Section 3. Projects have been identified, selected, prioritized and paced using the decision matrix presented in Figure 8, which is fully aligned with PUC Distribution's corporate goals, and as summarized below:

Identification

By taking into account all relevant information related to assets' operating condition, including service age, physical condition, results of visual inspections and testing, recent failure rates of similar assets in service, condition of all infrastructure assets were assessed and expressed on a normalized index in the form of a Health Index.

The Health Index was related to probability of failure values for each project, using a weighted average approach, as described in detail in Appendix B and each asset was assigned a health indicator expressed as "very good", "good", "fair", "poor" and "very poor."

Selection

Risk consequence related to reliability, safety, operating efficiency, etc. for each project area with assets found in "poor" or "very poor" condition were identified and calculated by multiplying composite probability of asset failure with consequence of failure. Costs for the scope of work to mitigate risk in each project area are determined, using distribution system estimating data.

Prioritization

A preliminary list of prioritized projects was produced, based on the risk score and risk mitigation cost for each project.

Based on the customer preferences, particularly those related to service quality, reliability, and retail rates, overall capital spending was established to align rate escalation to customer expectations. Budget availability for System Renewal projects was determined by subtracting from the overall capital spending level the higher priority projects in System Access.

The tools used to prioritize investments in this category include a project prioritizing matrix developed using Microsoft Excel.

Pacing

The selected projects on the preliminary project prioritized list were paced for implementation, based on the funding available for asset renewal and by taking into account the resources required for project implementation for the type of work predominantly involved (overhead, underground or substations).

Due to their non-discretionary nature, System Access projects will take priority in the event that there are competing demands with System Renewal projects. The use of a regularly updated integrated resource plan allows this process to be managed in an effective manner with the objective of successfully completing all projects planned for in the DSP.

4.2.3.3 System Service

Identification

Through careful planning processes including system capacity assessments, the development of a REG plan, and participation in preparing a Regional Infrastructure Plan, it has been identified that PUC Distribution's supply network has adequate capacity without any constraints to allow connection of new loads and generation from REG during the next five years. PUC Distribution has implemented a number of smart grid features during the previous years, such as smart meters, digital protection relays, voltage regulators, reclosers and remote-controlled substation switchgear to facilitate automation. A number of investments planned under System Renewal will serve to further expand the smart grid features, typically provided by System Service investments.

During customer engagement sessions, customers have indicated preference for lower retail rates as opposed to additional smart grid features, e.g. providing greater access to customers to manage and control their electricity use.

In view of the above, no investments are planned in this DSP, in the System Service category.

4.2.3.4 General Plant

There is only a small level of investments proposed in this DSP for General Plant category representing 1% of total investment. Approximately 5 years ago PUC consolidated all of its administrative offices and operational buildings into a newly constructed integrated facility and retired all of its aging facilities. For the most part the new facility is in excellent condition and meets all functional needs so only minimal incremental building infrastructure investments have been considered in this DSP. The entire motor vehicle fleet used for operations is owned by PUC Distribution Inc.'s non-regulated affiliate services company PUC Services Inc.

Identification, Selection, Prioritization & Pacing

General Plant projects are identified, selected, prioritized and paced based on cost/benefit analysis, using a combination of inspections, policies and expert knowledge. Investments into building repairs are based on identified deficiencies through inspections of building interior and exterior, doors and fixtures, HVAC, parking lots, security system and building mechanical systems.

4.3 System Capability Assessment for Renewable Energy Generation [5.4.3]

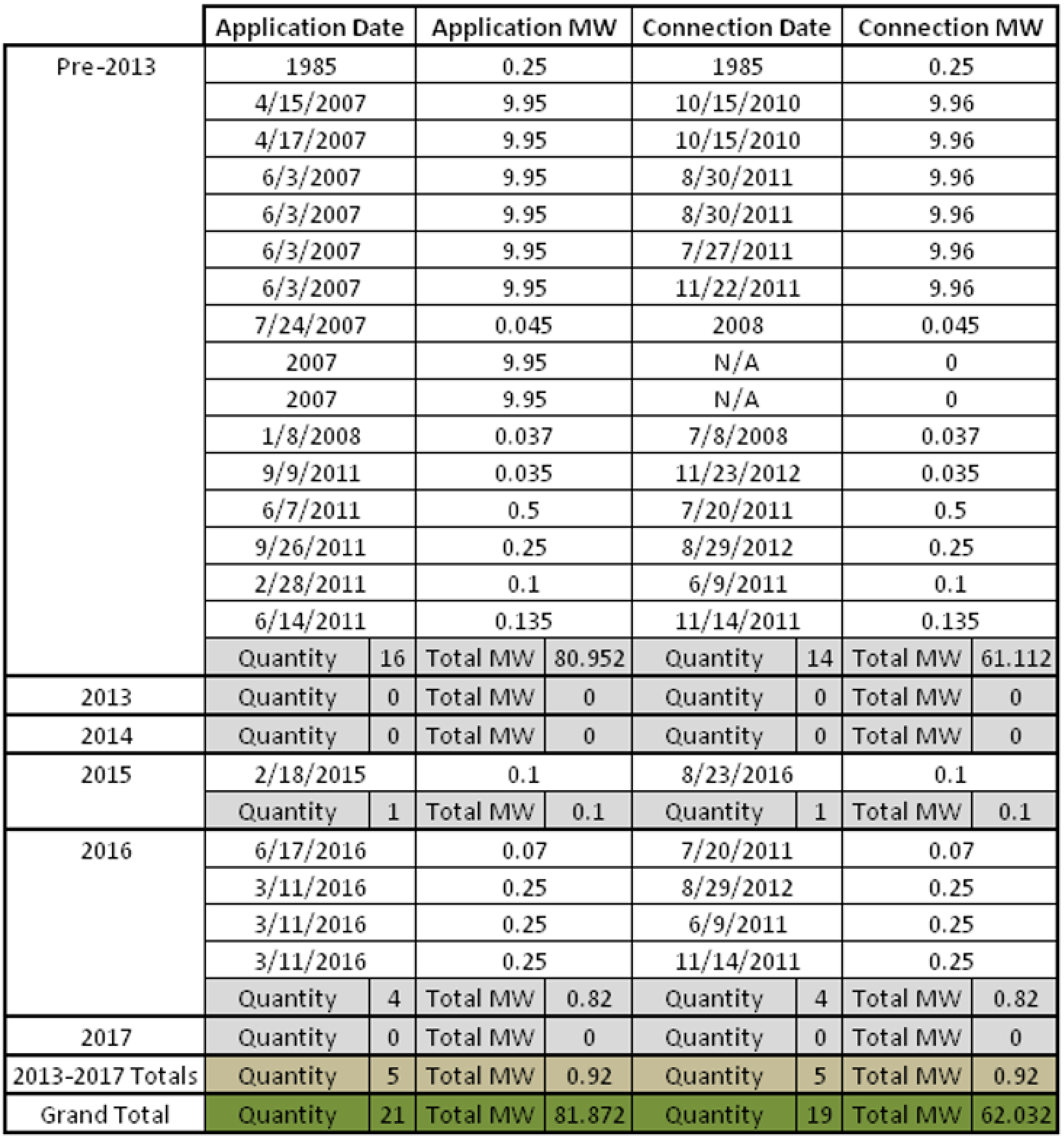
As previously described in Section 2.3.9, PUC Distribution currently has approximately 63MW of REG connected to its distribution system, which on occasion results in net export conditions during summer months when the distribution network is near its minimum load. PUC Distribution also hosts an IESO controlled 7MW/7MWh battery energy storage facility.

PUC Distribution has prepared and submitted a REG Plan to the IESO. The associated IESO comment letter in response to the REG Plan is attached in Appendix D.

4.3.1 Applications for REG Connections Greater than 10kW [5.4.3a]

The connection history for all REG installations connected to the PUC Distribution system over 10kW is summarized in Table 24 below. Of all the applications made, those that were not connected had applications terminated by the applicant and in no case was any application for connection rejected due to unavailable capacity.

Table 24: Summary of REG Applications >10kW



	Application Date		Application MW		Connection Date		Connection MW	
Pre-2013	1985		0.25		1985		0.25	
	4/15/2007		9.95		10/15/2010		9.96	
	4/17/2007		9.95		10/15/2010		9.96	
	6/3/2007		9.95		8/30/2011		9.96	
	6/3/2007		9.95		8/30/2011		9.96	
	6/3/2007		9.95		7/27/2011		9.96	
	6/3/2007		9.95		11/22/2011		9.96	
	7/24/2007		0.045		2008		0.045	
	2007		9.95		N/A		0	
	2007		9.95		N/A		0	
	1/8/2008		0.037		7/8/2008		0.037	
	9/9/2011		0.035		11/23/2012		0.035	
	6/7/2011		0.5		7/20/2011		0.5	
	9/26/2011		0.25		8/29/2012		0.25	
	2/28/2011		0.1		6/9/2011		0.1	
	6/14/2011		0.135		11/14/2011		0.135	
	Quantity	16	Total MW	80.952	Quantity	14	Total MW	61.112
2013	Quantity	0	Total MW	0	Quantity	0	Total MW	0
2014	Quantity	0	Total MW	0	Quantity	0	Total MW	0
2015	2/18/2015		0.1		8/23/2016		0.1	
	Quantity	1	Total MW	0.1	Quantity	1	Total MW	0.1
2016	6/17/2016		0.07		7/20/2011		0.07	
	3/11/2016		0.25		8/29/2012		0.25	
	3/11/2016		0.25		6/9/2011		0.25	
	3/11/2016		0.25		11/14/2011		0.25	
	Quantity	4	Total MW	0.82	Quantity	4	Total MW	0.82
2017	Quantity	0	Total MW	0	Quantity	0	Total MW	0
2013-2017 Totals	Quantity	5	Total MW	0.92	Quantity	5	Total MW	0.92
Grand Total	Quantity	21	Total MW	81.872	Quantity	19	Total MW	62.032

4.3.2 Applications for REG 10kW or less

Currently there are no applications in the queue from REG connections <10kW, under the Micro-FIT program and all requests for Micro-FIT generation received to date have been successfully connected to the system. There appears to be a growing interest in net metering and some discussions about that in conjunction with energy storage behind the meter as the gap closes between Micro-FIT contract pricing and the Residential class load energy costs.

4.3.3 System Capacity to Support REG [5.4.3c]

Primarily based on thermal ratings of conductors and transformers, PUC Distribution has developed and submitted to the IESO, the following table of available capacity, Table 25. The IESO uses this for planning and as an input to preparing a Transmission Availability Table (TAT) which is posted online to assist prospective REG applicants in selecting a site for their project. Table 25 summarizes available capacity at the 34.5kV feeder and station bus levels. It can be seen that at present there is still capacity available for the future connection of approximately 27MW more generation between circuits out of TS1 and TS2 combined.

Table 25: Available System Capacity for Accepting Additional REG Connections

Station	Bus Name	Capacity (MW)	Allocated Capacity (MW)	Available Capacity (MW)	Supply Circuit 1	Supply Circuit 2
TS1	**Total**	**45**	**41.310**	**3.690**	**GL1SM**	**GL2SM**
(St. Mary's)	West	30	21.009	3.690		
	East	30	20.300	3.690		
TS2	**Total**	**45**	**21.663**	**23.337**	**GL1TA**	**GL2TA**
(Tarentorus)	West	30	21.015	8.985		
	East	30	0.647	23.337		

34.5 kV Feeder Name	Bus Connection	Capacity (MW)	Allocated Capacity	Available Capacity (MW)	Notes:
SM-5	West	30	10.214	3.690	TS Limiting (45-D5) MW
SM-7	West	30	9.960	3.690	TS Limiting (45-D5) MW
Sub 19 West	West	N/A	0.835	N/A	no feeder, direct bus connection
SM-9	East	30	10.034	3.690	TS Limiting (45-D5) MW
SM-11	East	30	10.017	3.690	TS Limiting (45-D5) MW
Sub 19 East	East	N/A	0.250	N/A	no feeder, direct bus connection
TS1			**41.310**		
TA-6	West	30	0.139	23.337	TS Limiting (45-D8) MW
TA-7	West	30	20.876	8.985	West Bus Limiting (30-D9) MW
TA-9	East	30	0.028	23.337	TS Limiting (45-D8) MW
TA-10	East	30	0.188	23.337	TS Limiting (45-D8) MW
TA-11	East	30	0.431	23.337	TS Limiting (45-D8) MW
TS2			**21.663**		

4.3.4 Proposed Plan and Investments to Support REG [5.4.3b, d and e]

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.

PUC Distribution has produced a 5 year forecast of future REG connections as part of its Renewable Energy Generation Plan. For the period 2018-2022 projections have been based on:

- local economic and population data
- macro-economic conditions
- awareness of information from IESO and OEB regarding connection rates and programs

Based on those factors, a five year forecast has been established with an anticipated connection of one 250kW generator per year for a total connection of 1.25MW over the next 5 year period.

The PUC Distribution grid is presently very well positioned to support all forecast REG connections over the next five years and no associated infrastructure investment is required during that period.

4.4 Capital Expenditure Summary [5.4.4]

The actual capital and system O&M expenditure for the historic years from 2012 to 2016, as well as the proposed capital and system O&M expenditure for the bridge year (2017), the test year (2018) and the forecast period (2019 to 2022), is summarized in Table 26. For 2017, the data presented in each capital investment category and the system O&M category is the budgeted amount for the full 12 month period.

Table 26 reveals appreciable variations in the historic capital spending levels from one year to the next in each of the categories. The reasons for these variations are described below:

- The expenditure in the “System Access” category in 2012 far exceeds the average annual expenditure in this category for the five historic years. The excess expenditure in 2012 is related to the smart metering project. Although the installation work for the smart metering project was physically substantially complete at the end of 2010, the costs were not capitalized until 2012.

- The expenditure in the “System Access” category during 2015 and 2016 declined significantly in relation to the previous three years. This is related partly due to general slowdown in housing construction activity in this region and partly due to higher than normal requests in 2013 and 2014 for “make ready” work to allow joint-use of the poles lines for one of the major telecommunications companies.

- The expenditure in “System Renewal” category in 2013 is significantly higher in relation to the average expenditure in this category during the five historic years, which is related to the Sub 10 rebuild costs, capitalized during 2013.

- The expenditure in “General Plant” category in 2012 far exceeds the average expenditure in this category during the five historic years. The extraordinary high expenditure in 2012 in this category is related to the construction of the new office building.

As indicated in the System Service category in Table 26, there has been no expenditure during the past five years and minimal funds allocated during the forecast period. However, PUC Distribution has implemented a number of smart grid features on its network, during the previous years, such as smart meters, digital protection systems, voltage regulators and remote-controlled substation switchgear to facilitate automation, but because all of these projects involved replacement of old infrastructure at the end of its service life with new assets, these were included in the System Renewal category as it was the primary driver. System Service investments include input from customers to drive investment decision making. Examples include implementation of voltage regulation improvements and recloser installations in response to customer feedback and needs. The ability of the distribution grid to supply the existing and anticipated load and generation customers was analysed and it was concluded that there are no anticipated capacity constraints for the forecast period. As such, there are no investments proposed in this DSP, specifically triggered by System Service requirements.

Table 26: Capital and O&M Expenditure Summary

First year of Forecast Period: 2018

CATEGORY	Historical Period (budget & actual)															Bridge	Forecast Period (planned)				
	2012			2013			2014			2015			2016			2017[1]	2018	2019	2020	2021	2022
	Budget	Actual	Var	Budget	Actual	Var	Budget	Actual	Var	Budget	Actual	Var	Budget	Actual[2]	Var						
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000					
System Access	1,132	7,938	601.1%	1,069	2,310	116.1%	2,957	2,532	-14.4%	1,265	1,549	22.4%	1,215	1,212	-0.2%	1,271	1,511	1,615	2,086	1,604	1,560
System Renewal	6,043	4,821	-20.2%	6,525	6,083	-6.8%	3,813	3,754	-1.6%	4,753	4,640	-2.4%	4,543	4,244	-6.6%	3,372	3,761	6,906	3,296	4,533	7,093
System Service	-	-	--	-	-	--	-	-	--	-	-	--	-	-	--	38	-	-	-	-	-
General Plant	17,803	23,269	30.7%	1,314	2,028	54.4%	175	376	114.1%	69	67	-3.1%	-	83	--	-	86	55	62	60	55
TOTAL EXPENDITURE	24,978	36,028	44.2%	8,907	10,421	17.0%	6,946	6,661	-4.1%	6,087	6,256	2.8%	5,758	5,538	-3.8%	4,682	5,358	8,576	5,445	6,197	8,708
System O&M	$ 6,259	$ 5,853	-6.5%	$ 6,154	$ 5,992	-2.6%	$ 5,530	$ 5,773	4.4%	$ 5,819	$ 5,978	2.7%	$ 5,955	$ 5,978	0.4%	$ 5,857	$ 6,213	$ 6,306	$ 6,400	$ 6,496	$ 6,594

Notes to the Table:

1. For 2017 (bridge year), the data presented in each capital investment category and the system O&M category is the budgeted amount for the full 12 month period.

2. All values are net of contributed capital.

Explanatory Notes on Variances

Notes on shifts in forecast vs. historical budgets by category

The capital expenditure during the historic five years, after removing the extra ordinary expenditure related to construction of the office building and upgrade of the revenue meters with smart meters in 2012 and 2013, and it amounts to average annual capital expenditure of $6,680,745. These were excluded on the basis that they represent a one-time capital investment and are not attributable to the normal five-year asset management process applied in the DSP. This compares to the forecast average amount of $6,856,747 for the 2018 to 2022. The five year average (2012-2016) capital expenditure, inclusive of the one-time extraordinary capital expenditures, amounted to $12,981,005. Average annual capital for System Access has been forecast at 88% of historical average actual expenditures (2013-2016). Average annual capital for System Renewal has been forecast at 109% of historical average actual expenditures (2013-2016) due primarily to the planned construction of two substations in the forecast period. General Plant for the forecast period is generally unchanged from 2015 and 2016 actual expenditures.

Notes on year over year Budget vs. Actual variances for Total Expenditures

Refer to Section 2.3.5.1 for a high level summary of the budget versus actual capital variances on an annual basis. The key extraordanary expenditures pertained to the construction of a new office building as well as the upgrade of revenue meters with smart meters. The impacts of these one-time projects primarily impacted 2012 and 2013. There was an overall 2.1% increase in actual O&M expenditures from $5.85 million to $5.98 million over the 2012-2016 period.The variability of budgeted to actual O&M over the 5 year historical period ranged from -6.5% to 4.4%.

Notes on Budget vs. Actual variance trends for individual expenditure categories

In the System Access category, variance trends are contingent upon variable customer demand. For the years 2013 to 2016 for the System Renewal category, the general trend is that actual expenditures are slightly below budget.

The planned capital expenditure for the five-year forecast period, shown in Table 26, indicates capital expenditure by PUC Distribution, net of the customer or third-party contributions. As shown below in Figure 36, the planned expenditure will result in an average annual capital expenditure of approximately $6,856,747 during the period covered by this DSP.

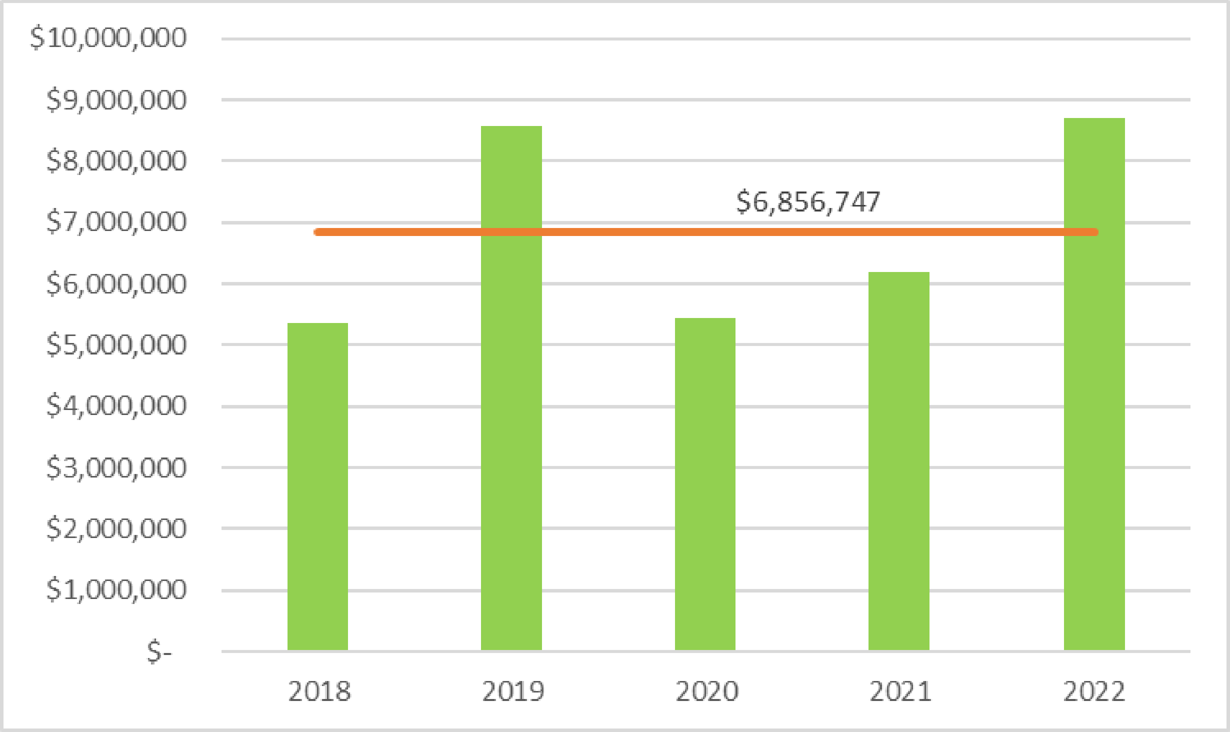


Figure 36: Proposed Capital Expenditure during the DSP Period

Figure 37 shows the capital expenditure during the historic five years, after removing the extra ordinary expenditure related to construction of the office building and upgrade of the revenue meters with smart meters in 2012 and 2013, and as shown it amounts to average annual capital expenditure of $6,680,745. These were excluded on the basis that they represent a one-time capital investment and are not attributable to the normal five-year asset management process applied in the DSP. The five year average (2012-2016) capital expenditure, inclusive of the one-time extraordinary capital expenditures, amounted to $12,981,005. This compares to the forecast average amount of $6,856,747.

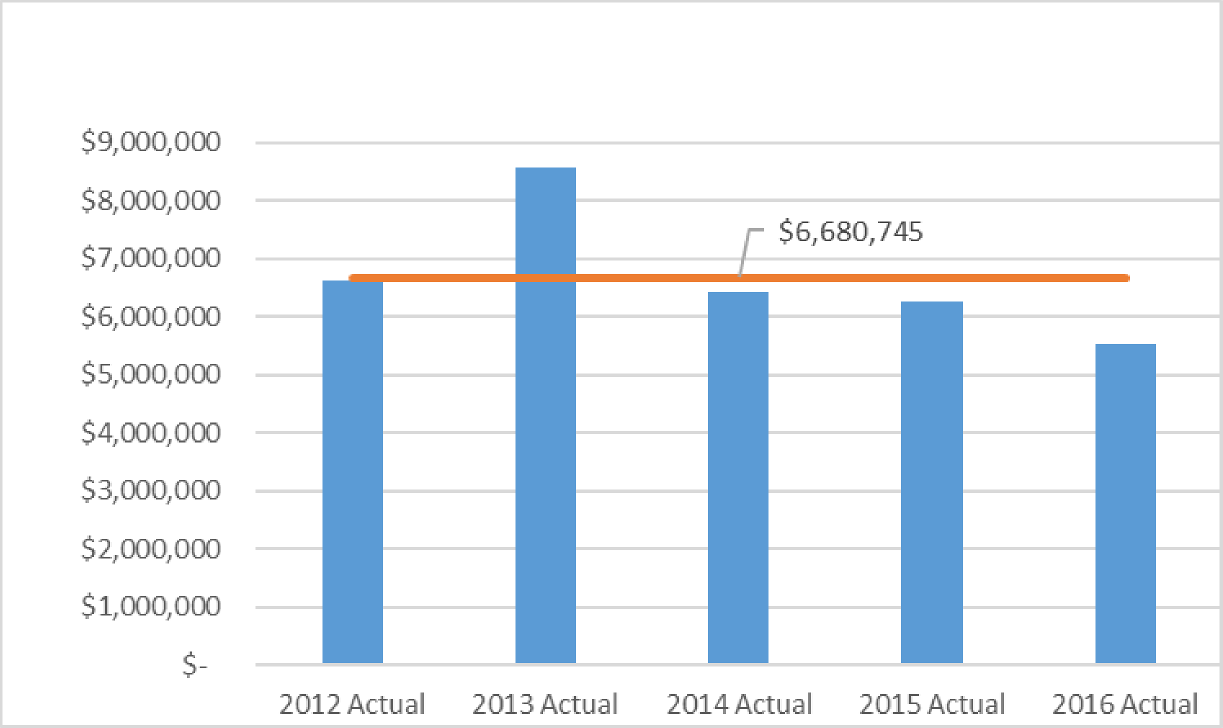


Figure 37: Historic Capital Expenditure (After Removing Office Building and Smart Meter Expenditure)

The proposed average annual expenditure during the DSP period, thus, represents an increase of 2.6% from the average annual capital expenditure during the historic five years. This figure does not account for inflationary increases. The impact of proposed capital expenditure in various categories on system O&M expenditure is described below:

4.4.1.1 System Access

These investments include capital investments to implement customer service requests, joint-use requests from third party communication companies; line relocates to facilitate municipal infrastructure developments, such as road reconstruction projects and investments into revenue metering. It is difficult to accurately determine the quantitative impact of the System Access investments on future O&M expenditure. However, investments into System Access generally result in an increase in future O&M expenditure. To connect new customers, in existing subdivisions, requires additional assets in the form of service lines, underground dips and revenue meters, all of which require safety inspections on a 3-year cycle and therefore, would result in an increase in O&M expenditure. New customers in new subdivisions require additional assets in the form of line extensions and distribution transformers in addition to service lines and revenue meters and thus result in an increase in O&M expenditure.

Equipping all general service customers with MIST meters is a regulatory requirement that will result in an increase in communication costs to each MIST meter and a corresponding increase in annual O&M expenditure.

4.4.1.2 System Renewal

The proposed investments into System Renewal are summarized in Table 21, with project level detail for the test year provided in Table 22 and in Appendix G. As shown, the proposed expenditure includes both reactive expenditures for replacement of the assets that have failed in service, as well as proactive replacement of assets where the risk of an assets' failure in service is unacceptable.

It is not possible to accurately determine the quantitative impact of capital investments on future O&M expenditure qualitatively, but in general when adequate level of investments is maintained into System Renewal to maintain the median age of asset base at the same level as in the previous year, it allows the asset's operating condition to be maintained at the same level as the previous year, preventing asset impairment from progressing further and preventing O&M costs from escalating further. When adequate investments are not made for renewal of assets which are at the end of their economic useful life, it results in an increase in equipment failures in service and an increase in the expenditure into emergency repairs and power restoration. Therefore, when correctly prioritized investments into asset renewal are made for renewal of assets at the end of their useful economic life, they prevent or slow down the rate of escalation of O&M costs in the coming years.

The infrastructure renewal projects involving distribution system operating voltage upgrade from 4.2 kV to 12.5 kV would result in a reduction in O&M expenditure due to the removal of duplicate lines and the replacement of three 4.2 kV distribution stations with a single 12.5 kV station.

4.4.1.3 System Service

Since there are no planned investments in the System Service category there is no expected change in O&M expenditure levels.

4.4.1.4 General Plant

Since the investments in General Plant are quite modest, they are not expected to have any material impact on O&M expenditure level.

4.4.1.5 Historic and Forecast O&M Expenditure

Figure 38 shows PUC Distribution's expenditure into system O&M activities during the historic five-year period. The chart indicates the mean annual O&M expenditure of $5, 914,777.

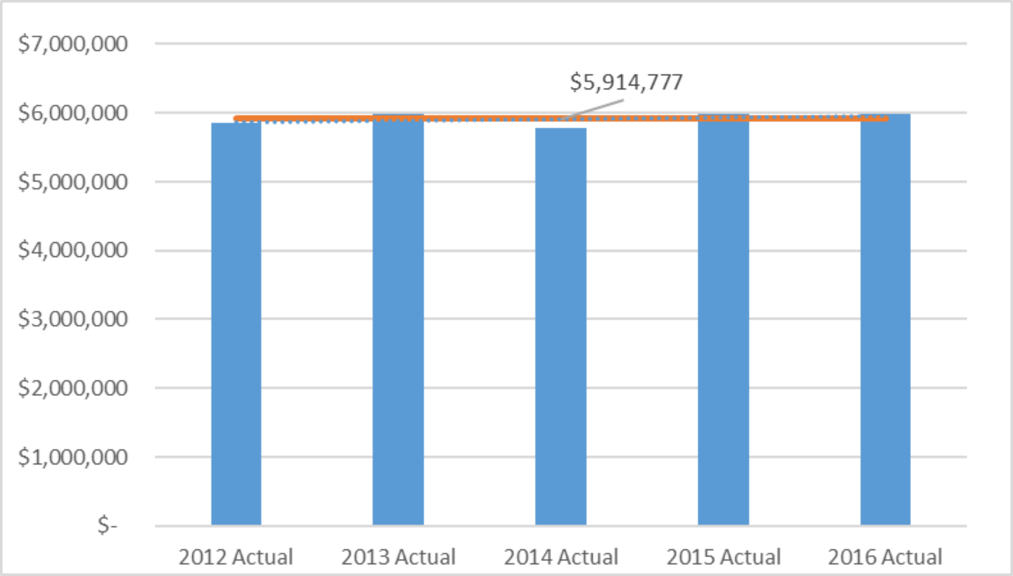


Figure 38: Historic O&M Expenditure

As shown, the deviations in year to year O&M expenditure from the mean are minor – maximum deviation from the mean in any year is less than 2.4%.

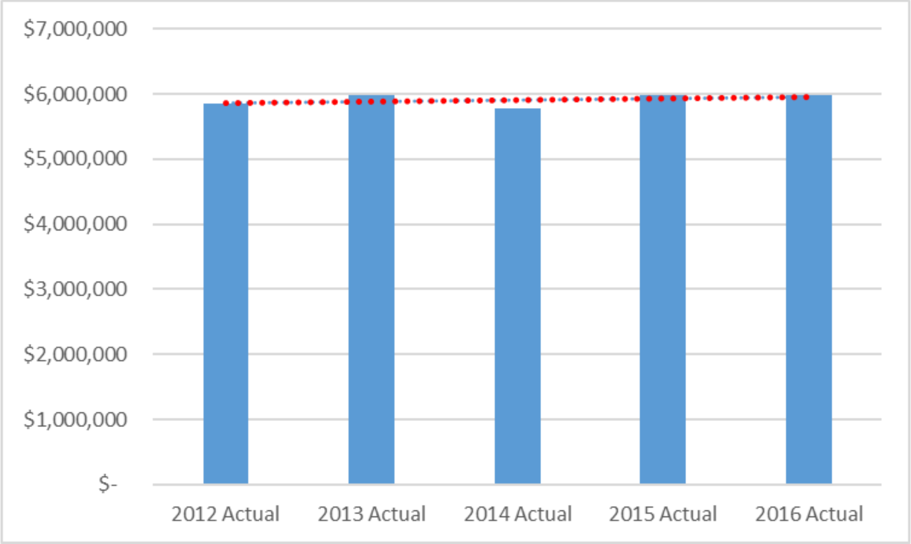


Figure 39: Historic O&M Expenditure with Trend line

Figure 39 shows the historic O&M expenditure with trend line – showing mean annual increase of 0.4% in O&M expenditure.

The forecast O&M expenditure as presented in Table 26 is displayed in Figure 40. Included in the O&M projections from 2019 to 2022 is an annual inflationary increase of 1.5%.

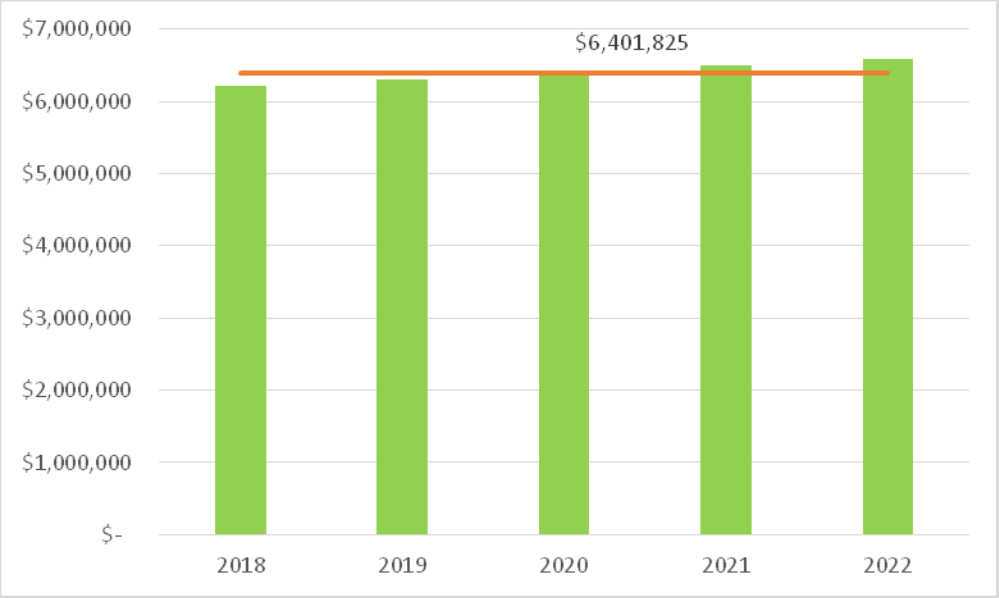


Figure 40: Forecast O&M Expenditure During DSP-Period

4.5 Capital Expenditure Justification [5.4.5]

4.5.1 Overall Plan Expenditure Justification [5.4.5.1]

As described in Section 4.4, the investment portfolio during the forecast period includes investments into System Access, System Service, System Renewal and General Plant upgrades. The capital investment plan proposed in the DSP amounts to a 2.6% increase in average annual expenditure during the forecast 5-year period from the historic 5-year period (after removing the extra ordinary expenditure for building construction and smart meters from the expenditure during the historic years). These were excluded on the basis that they represent a one-time capital investment and are not attributable to the normal five-year asset management process applied in the DSP. The five year average (2012-2016) capital expenditure, inclusive of the one-time extraordinary capital expenditures, amounted to $12,981,005. This compares to the forecast average amount of $6,856,747. Considering inflationary pressures, the overall average forecast spend is consistent with historical spending levels.

Because sufficient system capacity is available to meet existing and future capacity demand levels, including adequate capacity to allow connection of renewable generation and the economically efficient and customer desired smart grid features are being implemented during asset renewal; there are no new investments required in the System Service category.

Expenditure in System Access is driven by the need to meet regulatory obligations. The proposed expenditure level is estimated based on the historic spending levels and the specific information available about planned projects at the time of preparation of this DSP, related to new requests for services, line relocates, joint-use requests, MIST meters and requirements for revenue meter replacement.

Power supply reliability and public safety are the key drivers for the proposed investments into System Renewal. These investments are prioritized and paced based on objective, risk-based criteria, and the methodology employed for prioritization of the investments is aligned with the best industry practices. The investment level in this category has been determined to maintain risk related to asset failures in service, particularly those impacting safety, reliability and environment, at an optimal level.

Investment level into General Plant has been determined based on identified deficiencies through inspections of building interior and exterior, doors and fixtures, HVAC, parking lots, security system and building mechanical systems

For more detailed information on investment drivers and prioritization please refer to Section 2.1, Sections 3.1, 3.2, 3.3, 4.1 and 4.2.

4.5.2 Justification of Projects Exceeding the Materiality Threshold [5.4.5.2]

All capital projects, proposed to be implemented during the test year, with investments level exceeding the materiality threshold, are listed in Table 22 The first four projects in the table fall in the System Access category for which meeting the regulatory obligations is the primary driver and the next 9 projects on the list belong to the System Renewal category, for which supply system reliability and public safety are the primary drivers.

Detailed scope of each project along with its key driver and justification are described in detail in Appendix G and briefly summarized below:

Project #1, #2, #3, and #4 (System Access)

These projects are required to fulfil PUC Distribution’s regulatory obligations to provide services. The first project involves fulfilling customer requests for new services or upgrade of existing services. The second project covers requests from land developers involving servicing of multiple lots within subdivisions. The third project covers requests from telecommunication companies in the City for make ready work to facilitate joint use of distribution infrastructure by third parties. The fourth project involves meeting requests from the municipality to relocate overhead or underground lines installed in the public right-of-way to coordinate with road widening projects.

Project #5 and #6 (System Renewal – Forced)

These two projects involve reactive expenditure to restore power following a power interruption caused by equipment failures by replacing the failed distribution system assets with new equipment. The key drivers for these projects are supply system reliability and public safety, because when equipment has failed in service, the proposed expenditure becomes necessary to restore power and remove the unsafe equipment from service. Project #5 is intended to cover expenditure for renewal of failed assets on overhead lines and Project #6 is intended to cover expenditure for renewal of assets on underground distribution system.

Project #7

This project involves replacement of poles determined to be “unsafe” due to degradation of their structural strength, based on in-situ testing of the poles.

Project #8

This project involves rebuild of distribution station Sub 16. As detailed in the Asset Management Plan, this substation has been determined to be in very poor condition and at the end of life. The power transformers and switchgear at Sub 16 will reach a service age of 50 years by 2019, which is 10 years more than the typical life of this equipment. 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 distribution lines, which can impact system reliability whenever operating the existing Sub 16 is required. The planned Sub 16 rebuild will be a new 34.5kV - 12.47/7.2kV, 26.6MVA municipal substation that will have two incoming 34.5kV supplies, two 10/13.3 MVA power transformers, and four outgoing 12.47kV feeders supplied by arc resistant metalclad switchgear.

Projects #9

This project involves renewal of overhead distribution system assets through rebuilding of the overhead lines currently operating at 4.2 kV. The lines will be rebuilt to operate at 12.5 kV upon completion of the projects. As detailed in PUC Distribution's asset condition assessment report, PUC Distribution has over 30km of 4.16/2.4kV circuits in service, all of which are at the end of their service life. Additionally, the two stations supplying these overhead lines are also beyond their useful service life, requiring replacement. In an effort to streamline system voltages, three 4.2 kV stations will be replaced with a single station producing 12.47/7.2kV distribution voltage. In order to accommodate these station rebuilds, all distribution lines operating at 4.2 kV will be converted to 12.5 kV. Power system reliability and public safety are the primary driver for these projects, although they will also help reduce operating costs when the two 4.2 kV stations are retired from service.

Projects #10, #11, and #12

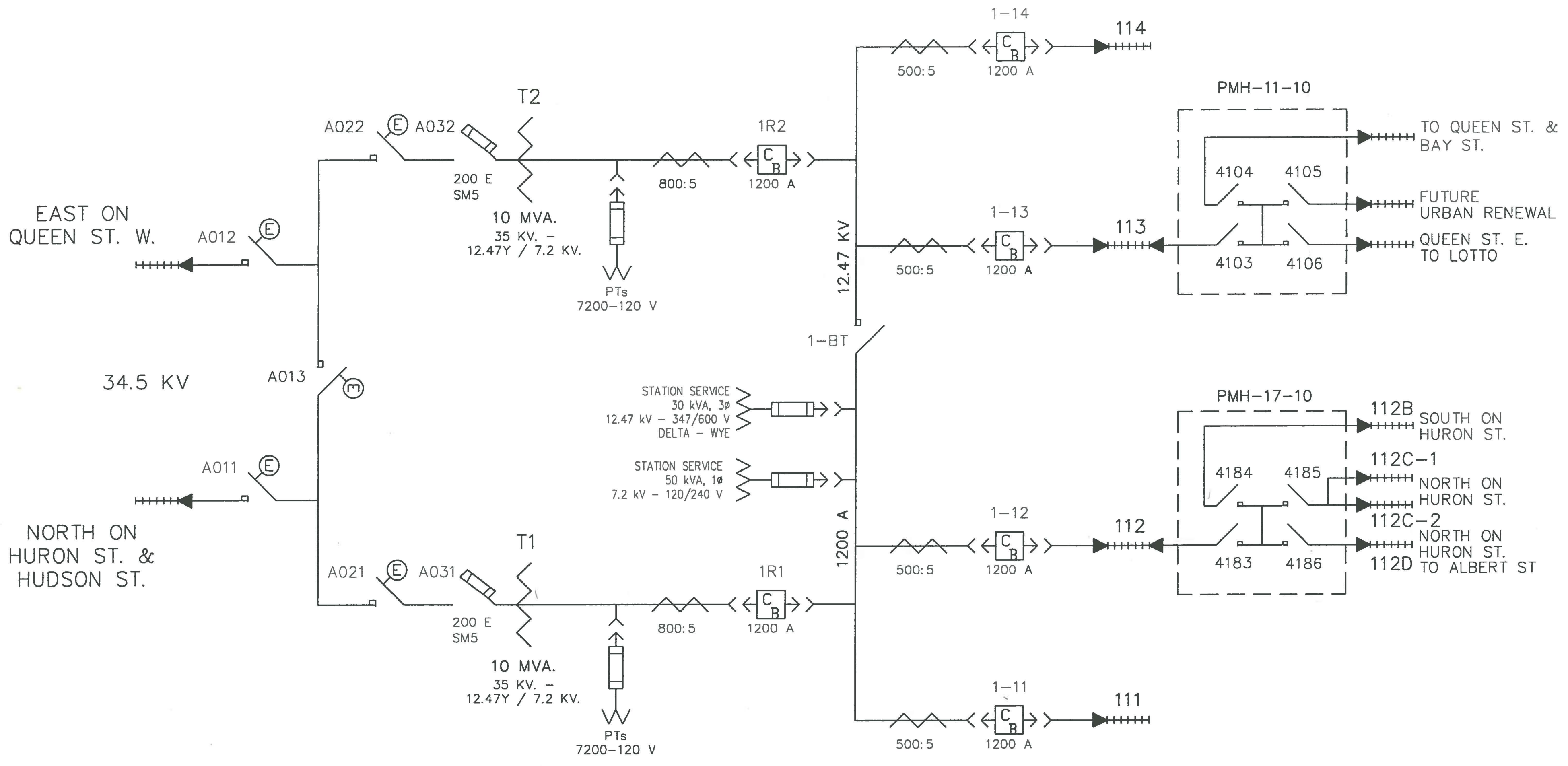
PUC Distribution has identified #6 copper overhead primary conductor as a safety hazard. It is classified by PUC Distribution as "restricted wire". Due to the nature of the conductor, it being small and constructed of copper, its tensile strength is known to degrade over years of use. Due to this, the conductor is prone to failure. Additionally, when the conductor fails, due to its nature, the fault current dissipates quickly and therefore may not trigger the nearest protective equipment. This may cause the conductor to remain energized in an area where staff or the public may come into contact. The conductor is replaced with #2ACSR, along with related insulation and aged infrastructure. The specific project areas covered by these projects have been identified as a high priority. Public and worker safety is the primary investment driver for this project.

Projects #13

This project involves renewal of underground distribution system assets by rebuilding of the existing underground distribution system currently operating at 4.2 kV. The underground lines will be rebuilt to operate at 12.5 kV upon completion of the projects. As detailed in PUC Distribution's asset condition assessment report, PUC Distribution has approximately 3km of 4.16/2.4kV underground circuits in service, all of which are at the end of their service life. Additionally, the 4.2 kV stations supplying these underground lines are also beyond their useful service life, requiring replacement. In an effort to streamline system voltages, three stations will be replaced with a single station producing 12.47/7.2kV distribution voltage. In order to accommodate these station rebuilds, all underground feeder cables operating at 4.2 kV will be converted to 12.5 kV. Power system reliability and public safety are the primary driver for these projects, although they will also help reduce operating costs when the two 4.2 kV stations are retired from service.

Appendix A

Single Line Diagrams



Scale: NTS

No.	Revision	Date	Initial
1	REVISED STATION SERVICE INFO, PTs, BORDER AND DRAWING NUMBER	MAY. 18/06	J.T.

PUC

SUBSTATION #1

SCHEMATIC DIAGRAM

Drawn by: J.R.	Date: JAN. 26/88
Checked by: K.B.	Date: MAY 18/06
Approved by:	Date: May 25/06
Drawing Number: A–ES01–04–001	Rev. 1

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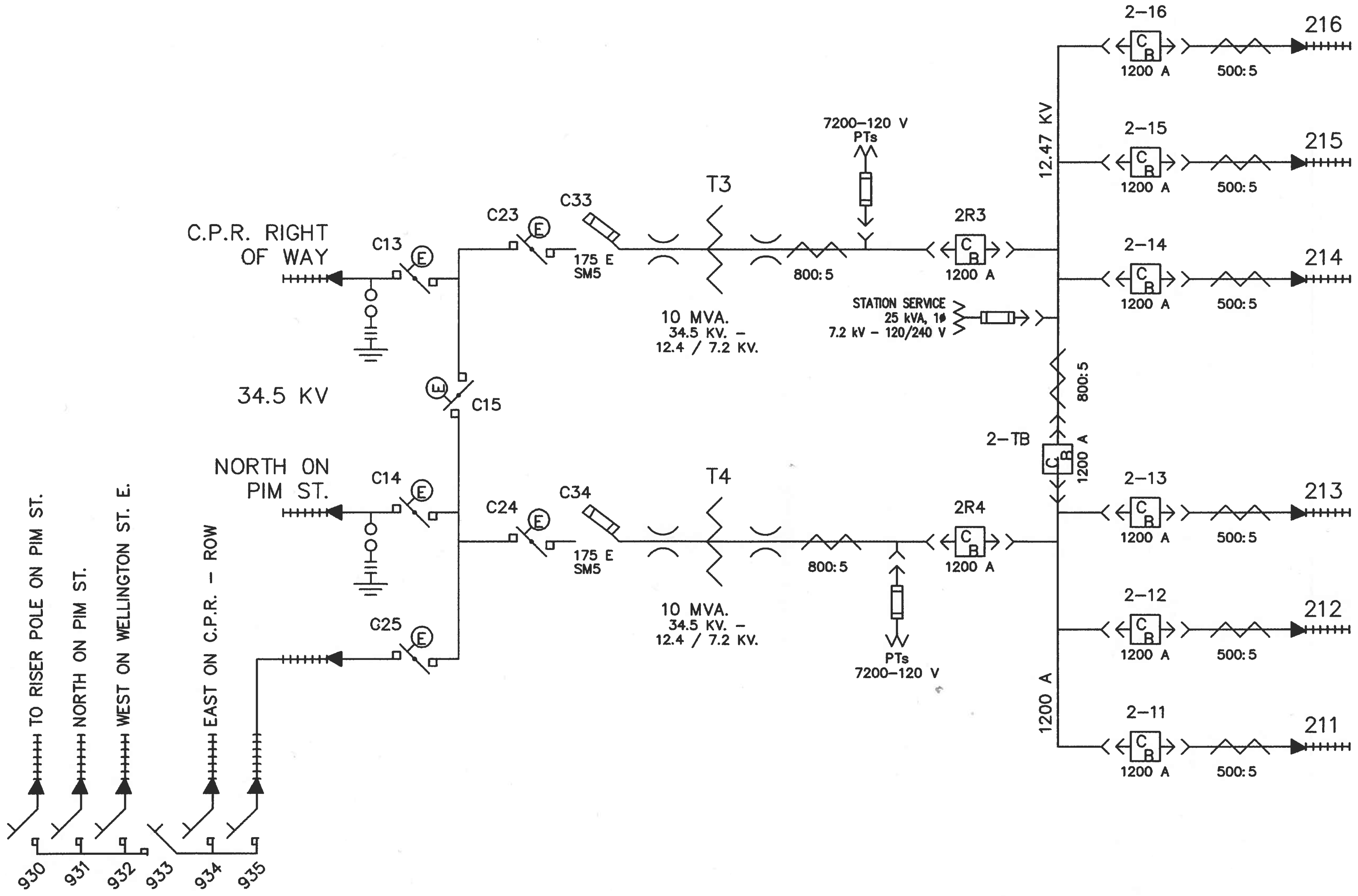


Scale: NTS

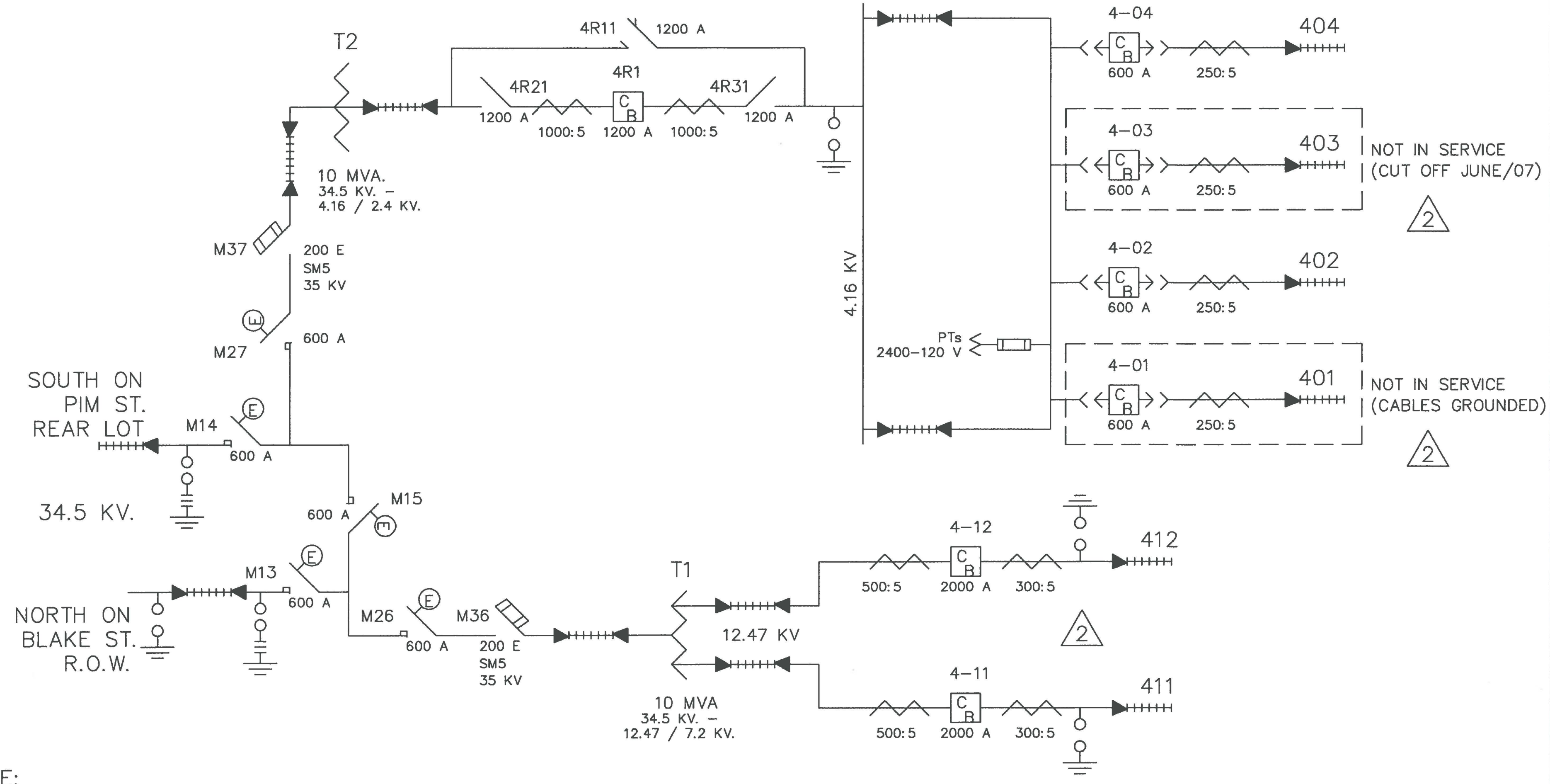
No.	Revision	Date	Initial
2	MOVED STATION SERVICE TO OTHER SIDE OF TIE BREAKER	OCT. 18/15	M.P.
1	REVISED BORDER AND DRAWING NUMBER AND ADDED STATION SERVICE.	MAY. 18/06	J.T.

PUC

SUBSTATION #2

SCHEMATIC DIAGRAM

Drawn by: J.R.
Date: JAN. 13/88
Checked by: K.B.
Date: MAY 18/06
Approved by:
Date: 2018/02/04
Drawing Number: A-ES02-04-001
Rev. 2



NOTE:

STATION SERVICE FED FROM CIRCUIT 411 AT POLE #12103.

No.	Revision	Date	Initial
2	RELOCATED ARRESTORS AT CCTS. 411, 412. CCTS. 401 & 403 NOW N.I.S.	MAR. 9/16	J.T.
1	REVISED BORDER AND DWG. NUMBER. ADDED PTs AND STA. SERV. NOTE.	MAY 18/06	J.T.

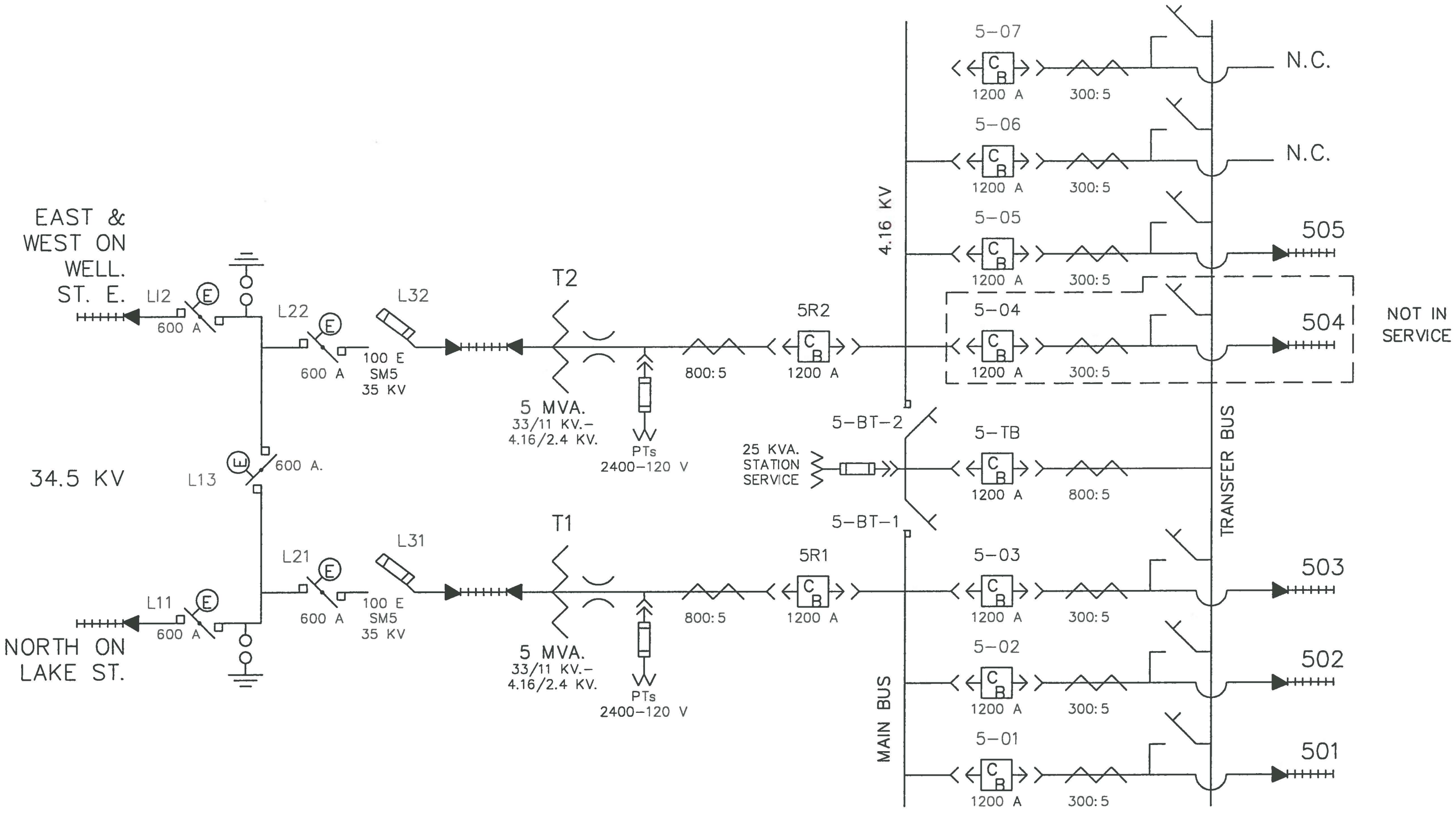
PUC

SUBSTATION #4

SCHEMATIC DIAGRAM

Scale: NTS

Drawn by: J.R.	Date: SEP. 11/86
Checked by: K.B.	Date: MAY 18/06
Approved by:	Date: 2016/03/09
Drawing Number: A–ES04–04–001	Rev. 2



No.	Revision	Date	Initial
1	REVISED BORDER AND DWG. NUMBER. REMOVED CCT. 504 FROM SERVICE.	MAY. 18/06	J.T.

PUC

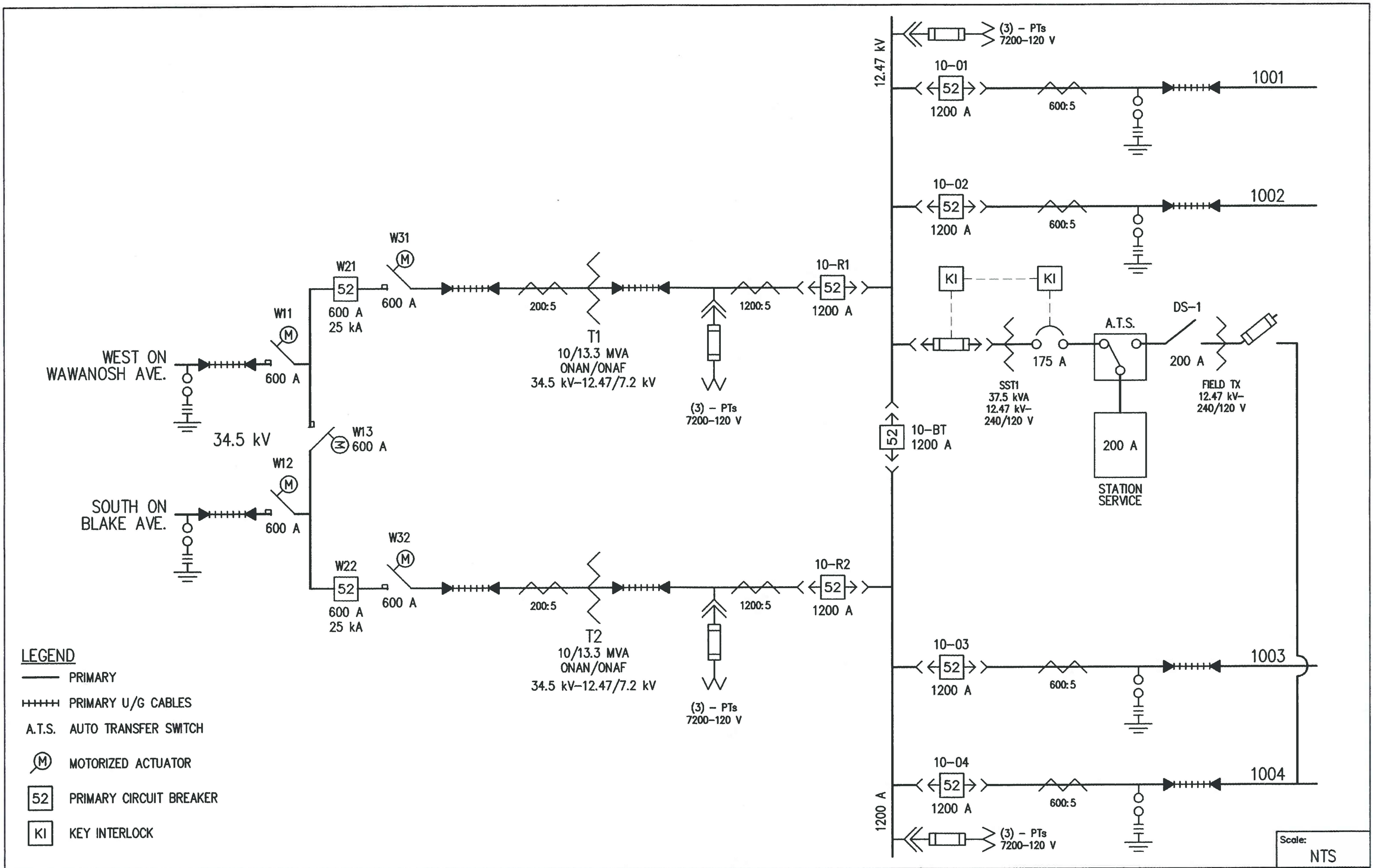
SUBSTATION #5

SCHEMATIC DIAGRAM

Scale: NTS

Drawn by: J.R.	Date: SEP. 11/86
Checked by: K.B.	Date: MAY 18/06
Approved by:	Date: May 25/06.
Drawing Number: A-ES05-04-001	Rev. 1

K:\Engineering Data\Drawings\TS1, TS2 and Substations\Substation and TS Schematics\A-ES05-04-001 - REV. 01.dwg



Scale: NTS

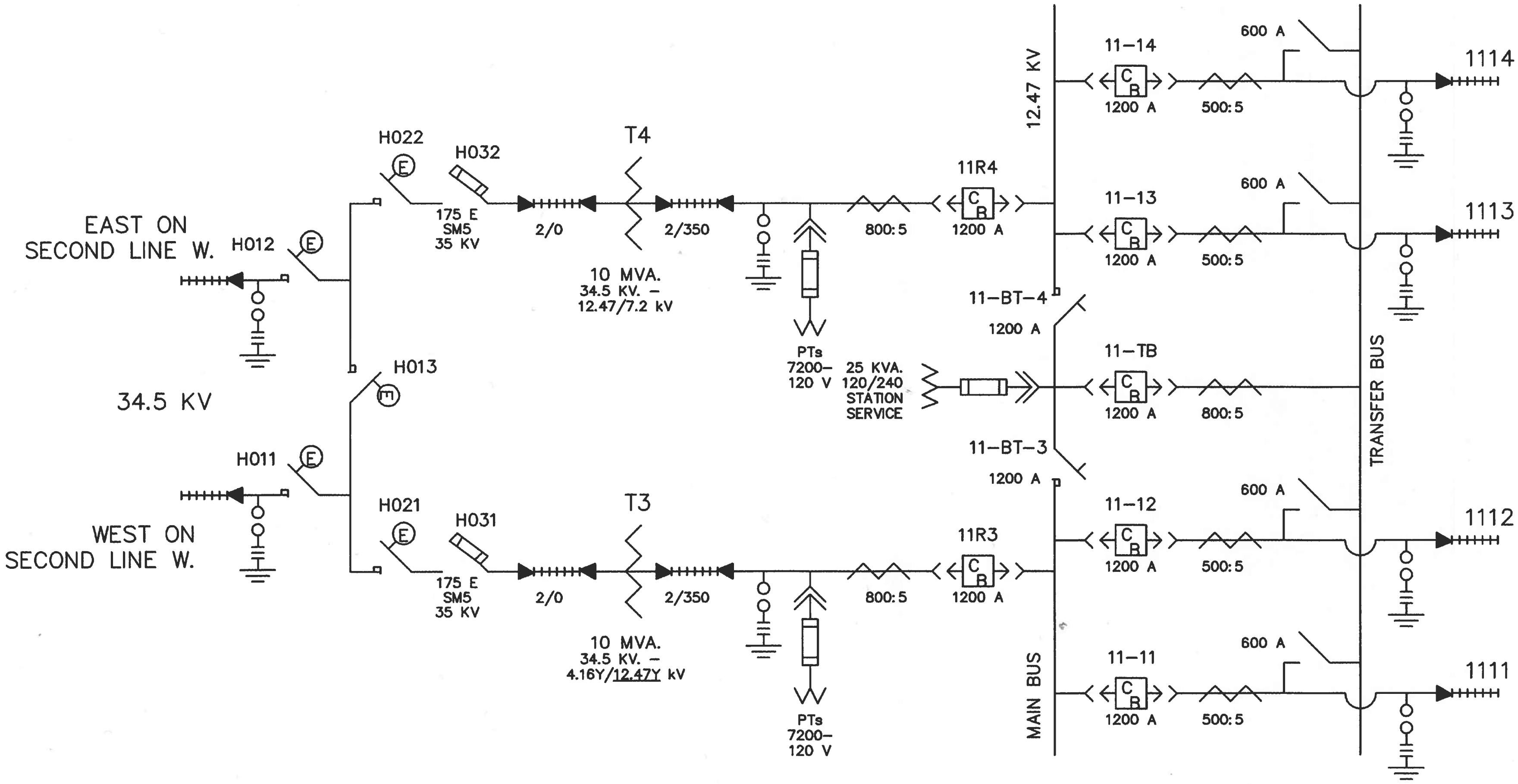
No.	Revision	Date	Initial
2	SUBSTATION REBUILT	NOV. 24/17	J.T.
1	REVISED INCOMING SOURCE AND VOLTAGE, BORDER, DWG. #, PTs AND STA. SERV.	MAY 18/06	J.T.

PUC

SUBSTATION #10

SCHEMATIC DIAGRAM

Drawn by: J.R.
Date: SEP. 11/86
Checked by: K.B.
Date: MAY 18/06
Approved by:
Date: 2017/11/29
Drawing Number: ~~A~~-ES10-04-001
Rev. 2



No.	Revision	Date	Initial
2	REVISED VOLTAGE RATING ON T3.	JAN. 4/18	J.T.
1	REVISED BORDER AND DWG NUMBER. REMOVED REFERENCE TO SUB. 6.	MAY 18/06	J.T.

PUC

SUBSTATION #11

SCHEMATIC DIAGRAM

Scale: NTS

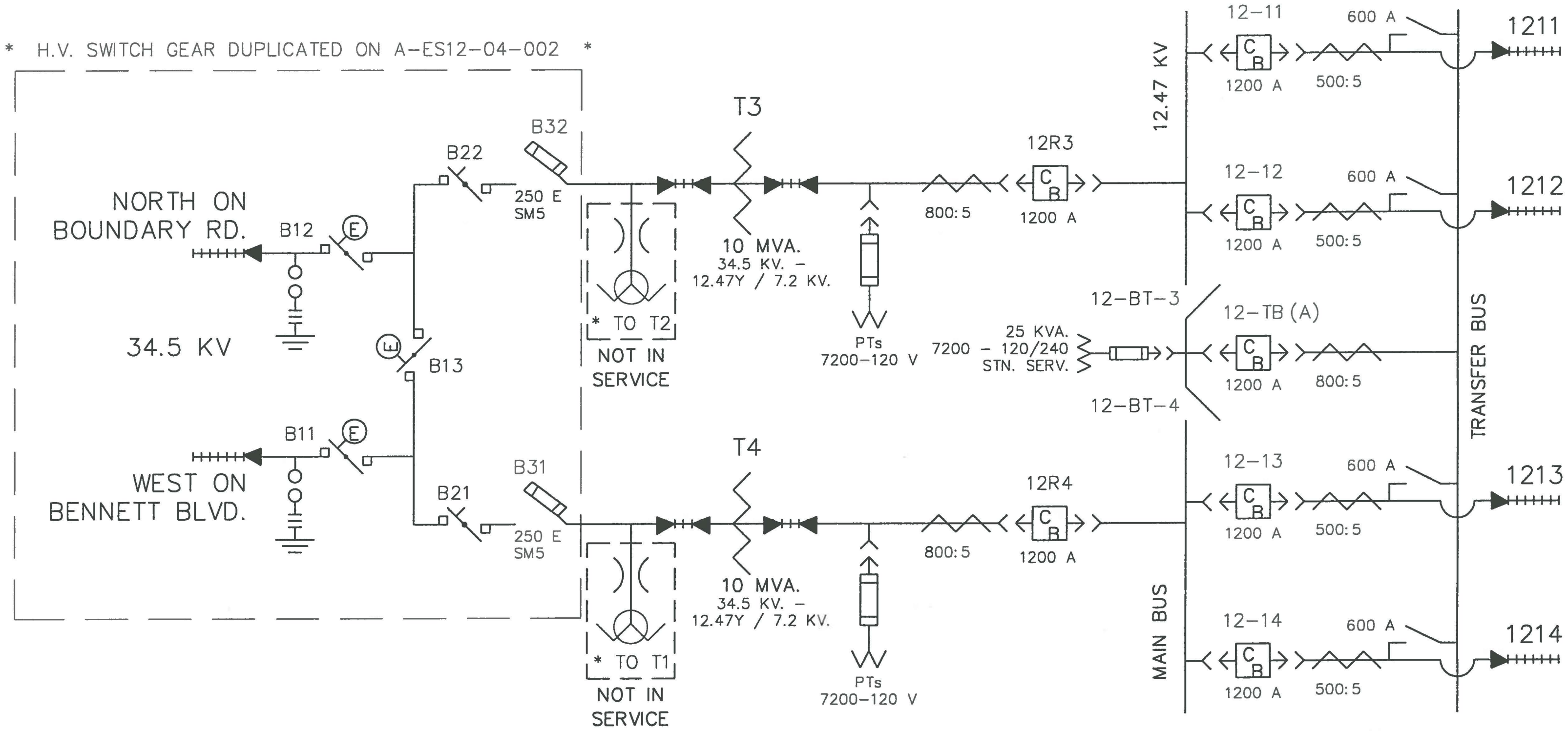
Drawn by: J.R.
Date: SEP. 11/86

Checked by: K.B.
Date: MAY 18/06

Approved by:
Date: 2018/01/04

Drawing Number: A–ES11–04–001
Rev. 2

* H.V. SWITCH GEAR DUPLICATED ON A-ES12-04-002 *



No.	Revision	Date	Initial
1	REVISED BORDER AND DRAWING NUMBER. REMOVED T1 & T2 FROM SERVICE.	MAY. 18/06	J.T.

PUC

Scale: NTS

SUBSTATION #12

SCHEMATIC DIAGRAM
12.47 kV

Drawn by: J.R.	Date: SEP. 11/86
Checked by: K.B.	Date: MAY 18/06
Approved by: H Bell	Date: May 25/06.
Drawing Number: A–ES12–04–001	Rev. 1

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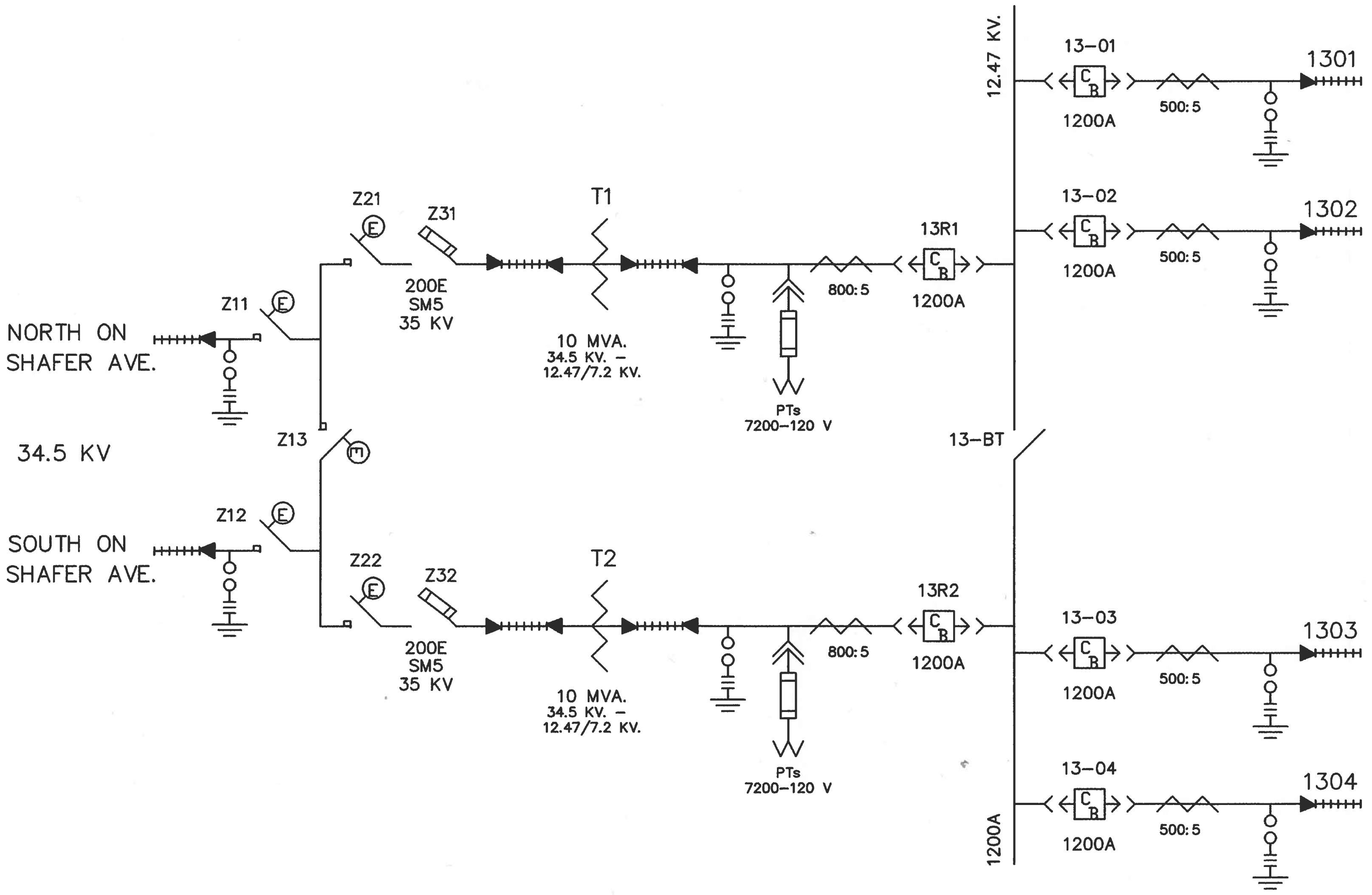


NOTE:
STATION SERVICE NORMALLY FED FROM CIRCUIT 1301
ON SHAFER AVE. TRANSFORMER LOCATED AT
INTERSECTION OF SHAFER AND BAINBRIDGE.

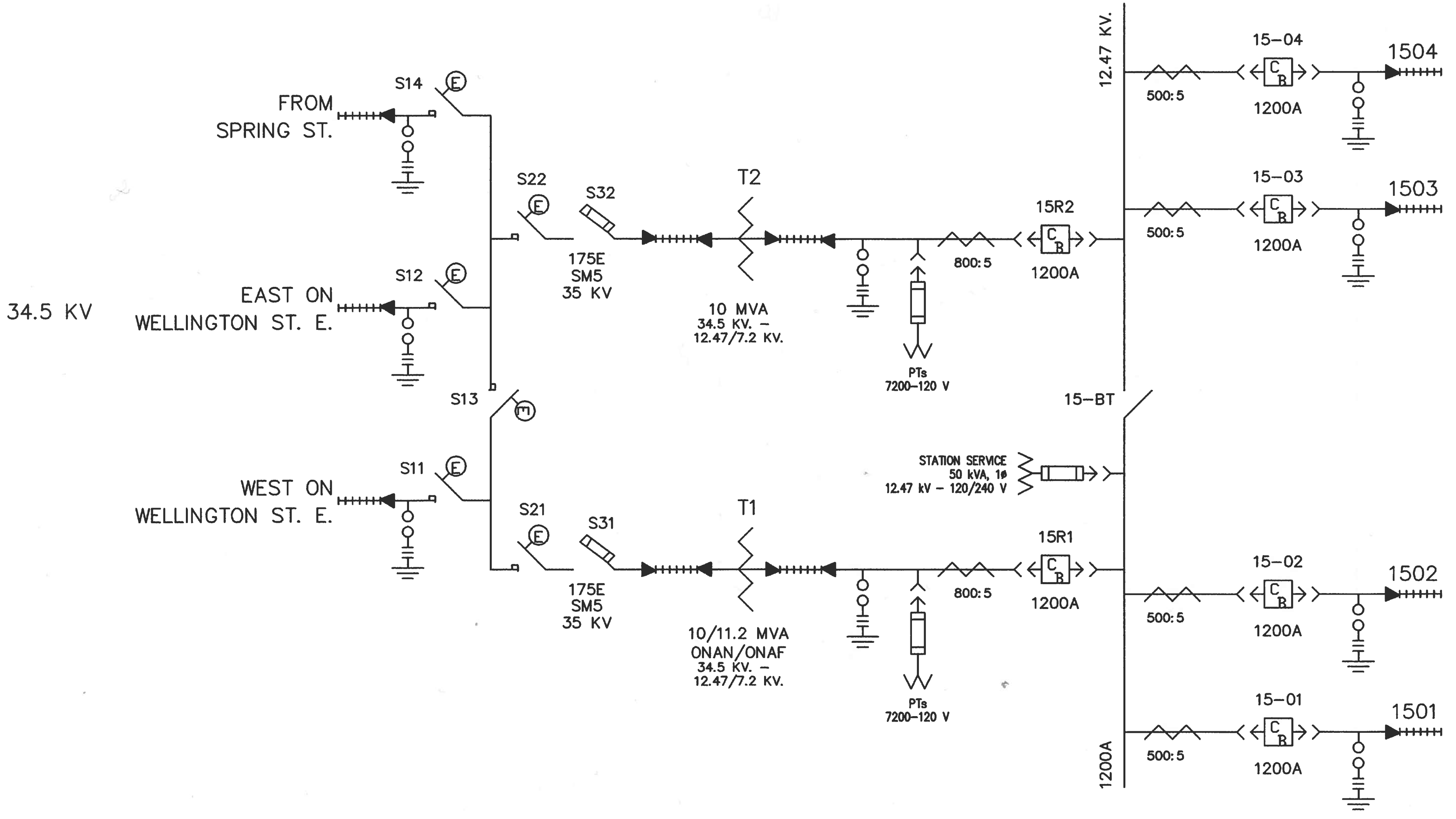
No.	Revision	Date	Initial
2	ADDED STATION SERVICE NOTE	JAN. 4/18	J.T.
1	REVISED BORDER AND DRAWING NUMBER	MAY 18/06	J.T.

PUC

SUBSTATION #13

SCHEMATIC DIAGRAM

	Scale: NTS
Drawn by: J.R.	Date: APR. 10/87
Checked by: K.B.	Date: MAY 18/06
Approved by:	Date: 2018/01/04
Drawing Number: A-ES13-04-001	Rev. 2



No.	Revision	Date	Initial
2	PLACED T1 IN SERVICE	FEB. 14/13	J.T.
1	REVISED BORDER & DWG No., ADDED STA. SERV. & REVERSED FEEDER CBs & CTs.	MAY. 18/06	J.T.

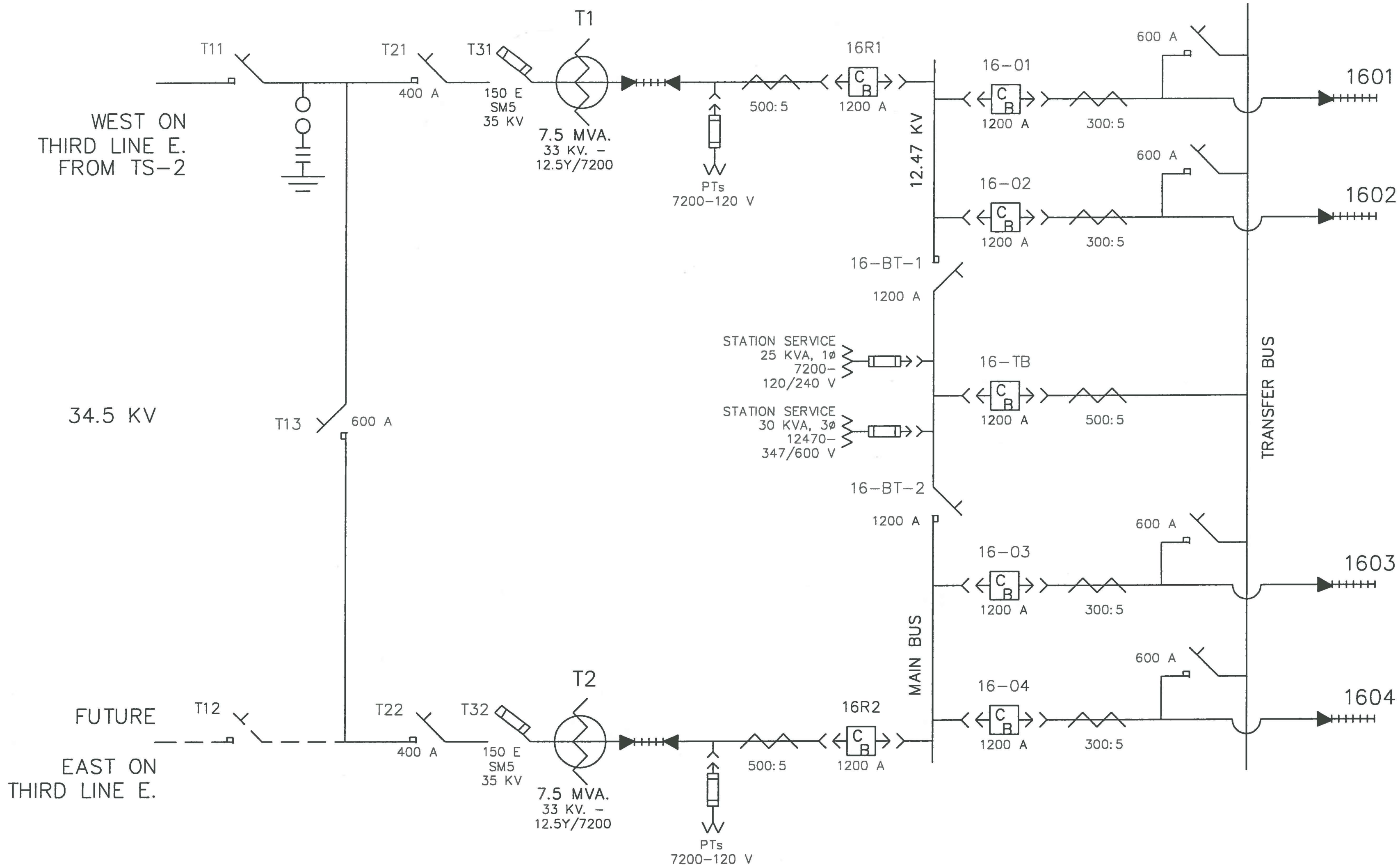
PUC

SUBSTATION #15

SCHEMATIC DIAGRAM

Scale: NTS

Drawn by: V.F.	Date: JUN. 15/95
Checked by: R.H.	Date: FEB. 14/13
Approved by:	Date: 2018/01/04
Drawing Number: ~~A-~~ES15-04-001	Rev. 2



Scale:
NTS

No.	Revision	Date	Initial
1	REVISED BORDER AND DWG. NUMBER. REVISED STATION SERVICE XFMRS.	MAY. 18/06	J.T.

PUC

SUBSTATION #16

SCHEMATIC DIAGRAM

Drawn by: J.R.
Date: SEP. 11/86
Checked by: K.B.
Date: MAY 18/06
Approved by:
Date: May 25/06
Drawing Number: A–ES16–04–001
Rev. 1

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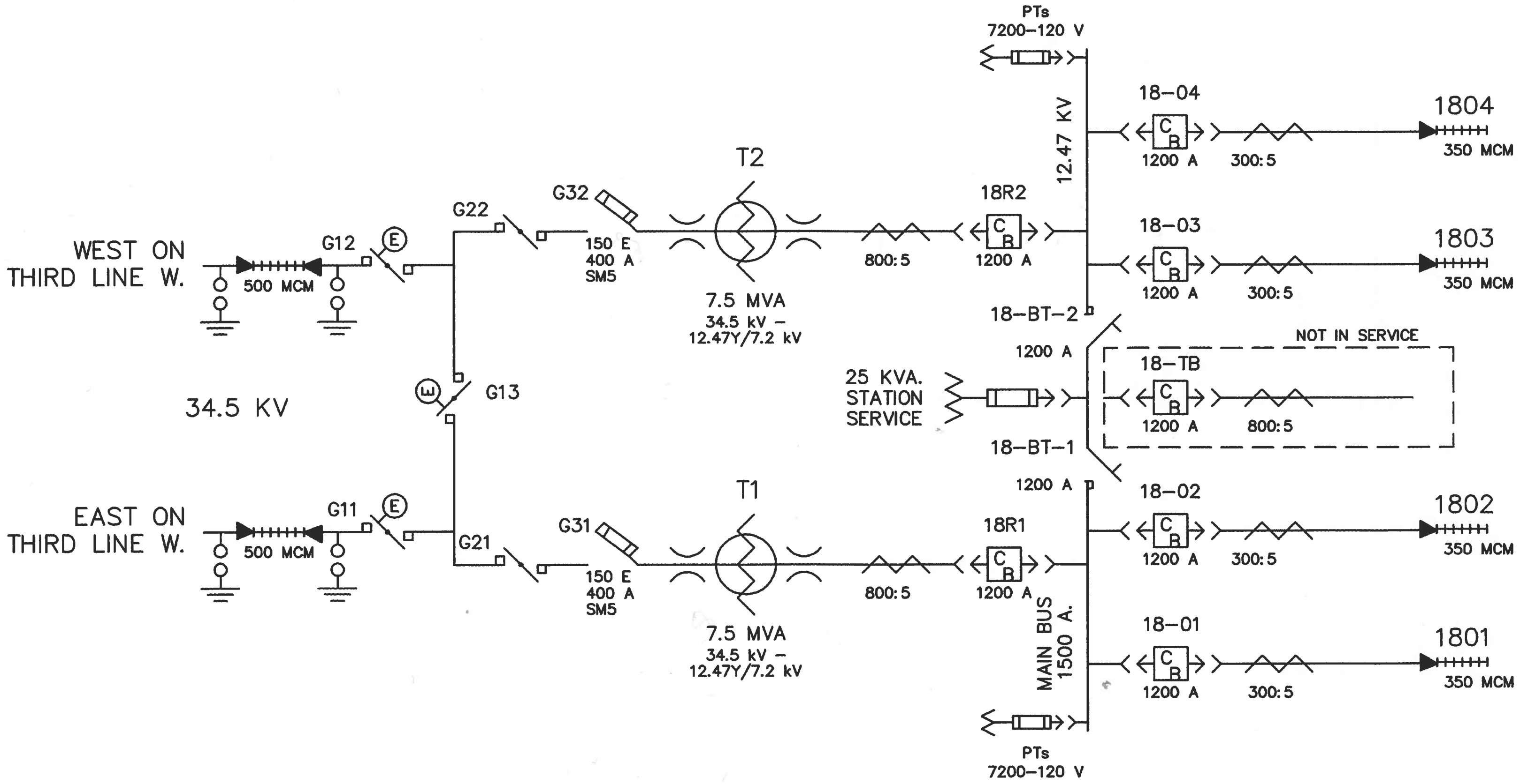


No.	Revision	Date	Initial
2	UPDATED TX RATINGS	JAN. 4/18	J.T.
1	REVISED BORDER AND DWG. No., REMOVED TRANSFER BUS AND SWITCHES.	MAY 18/06	J.T.

PUC

SUBSTATION #18

SCHEMATIC DIAGRAM

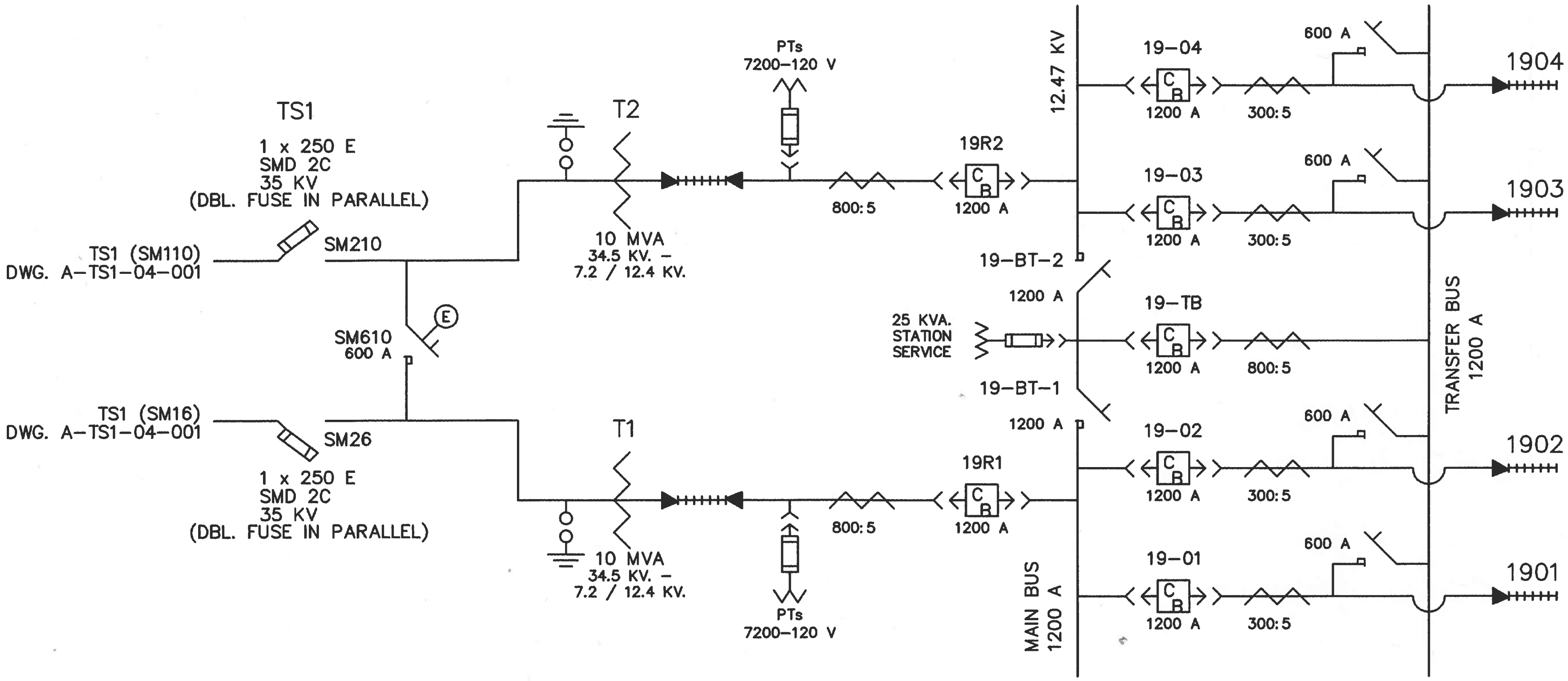
Scale: NTS

Drawn by: J.R.
Date: SEP. 11/86

Checked by: K.B.
Date: MAY 18/06

Approved by:
Date: 2018/01/04

Drawing Number: A–ES18–04–001
Rev. 2



Scale:
NTS

No.	Revision	Date	Initial
2	TS1 CONNECTIONS REVISED	JAN. 4/18	J.T.
1	REVISED BORDER AND DRAWING NUMBER.	MAY 18/06	J.T.

PUC

SUBSTATION #19

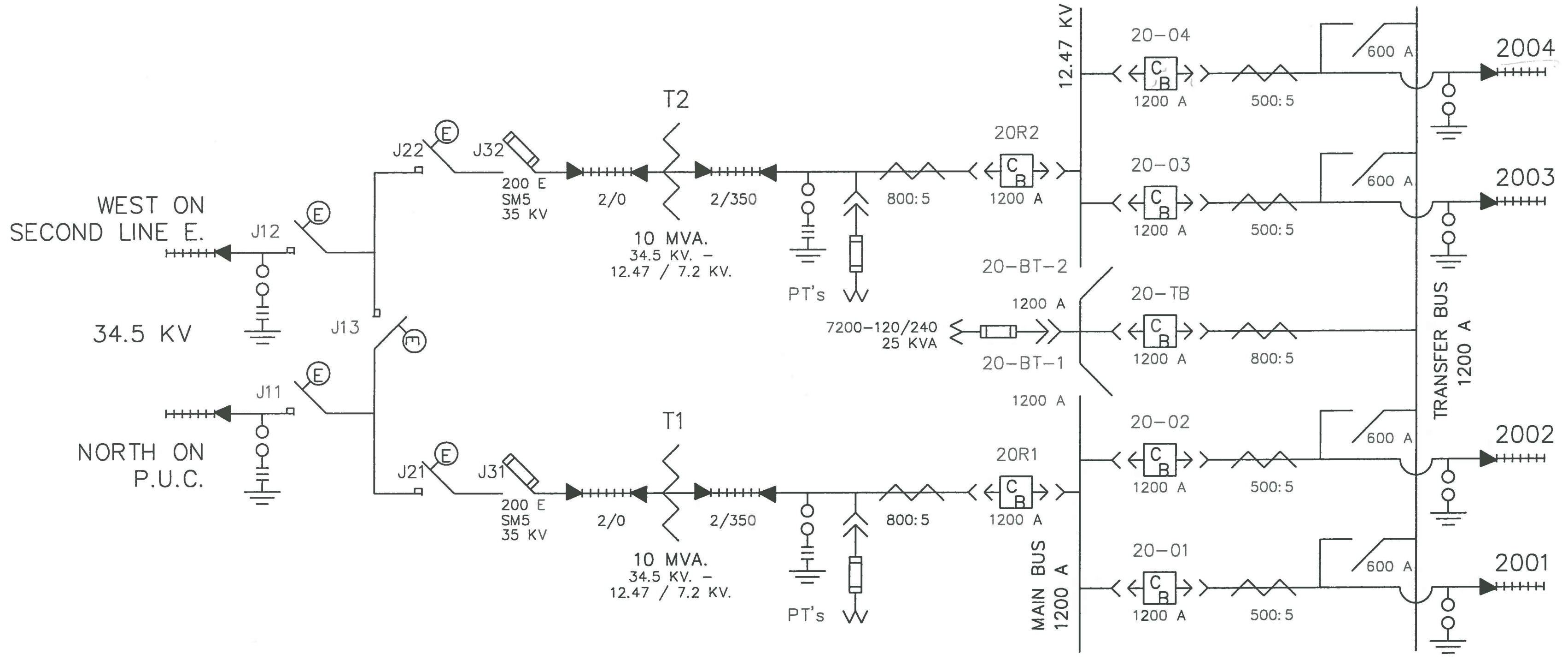
SCHEMATIC DIAGRAM

Drawn by: J.R.
Date: JUN 18/86

Checked by: K.B.
Date: MAY 18/06

Approved by:
Date: 2018/01/04

Drawing Number: A-ES19-04-001
Rev. 2



No.	Revision	Date	Initial
1	REVISED BORDER AND DRAWING NUMBER.	MAY. 18/06	J.T.

PUC

SUBSTATION #20

SCHEMATIC DIAGRAM

Scale: NTS

Drawn by: J.R.

Date: SEP. 11/86

Checked by: K.B.

Date: MAY 18/06

Approved by: K Bell

Date: May 25/06.

Drawing Number: A–ES20–04–001

Rev. 1

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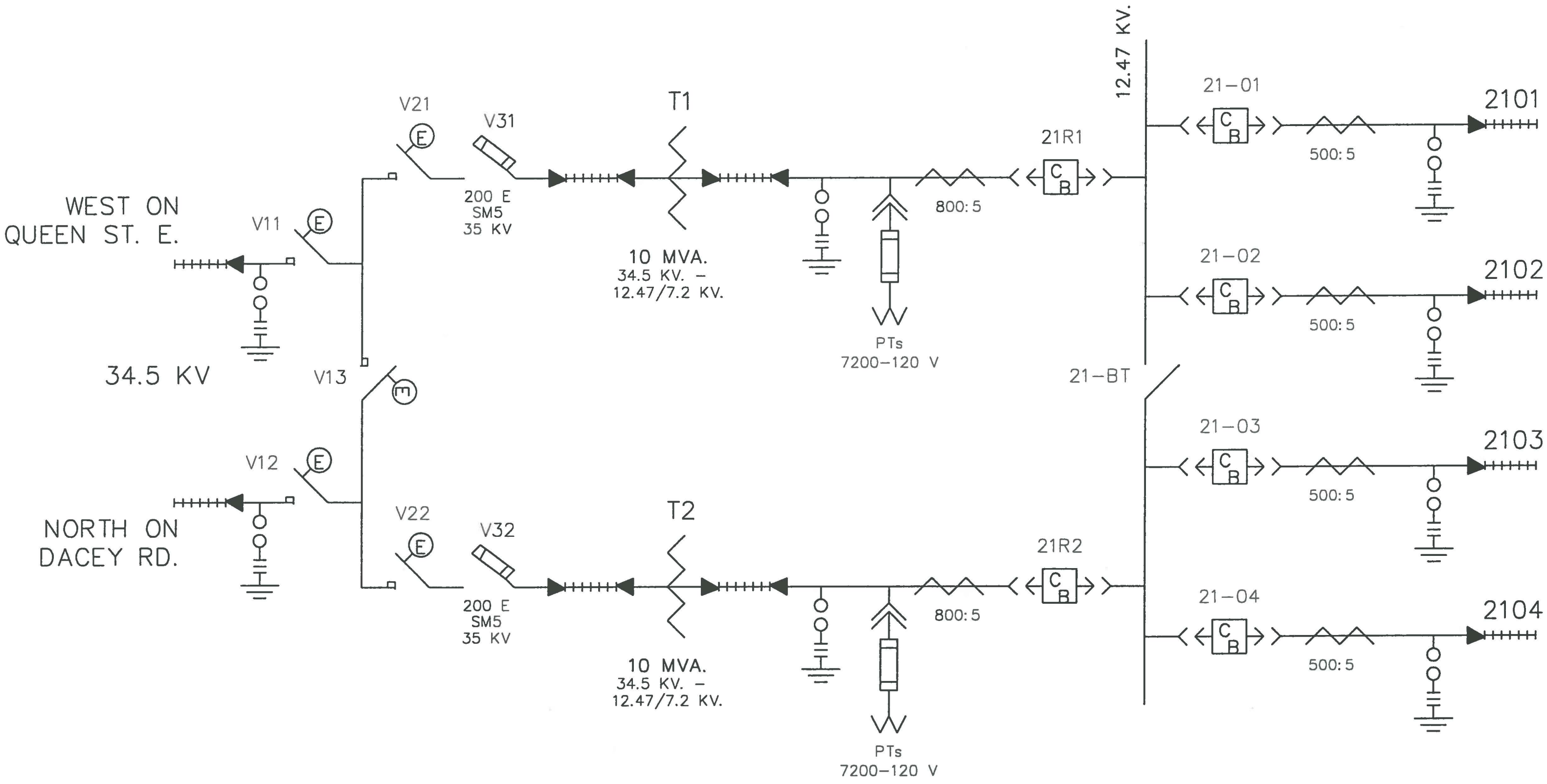

Scale: NTS

No.	Revision	Date	Initial
1	REVISED BORDER AND DRAWING NUMBER. ADDED PT RATINGS.	MAY. 18/06	J.T.

PUC

SUBSTATION #21

SCHEMATIC DIAGRAM

Drawn by: J.R.	Date: SEP. 11/86
Checked by: K.B.	Date: MAY 18/06
Approved by: RDBell	Date: May 25/06.
Drawing Number: A–ES21–04–001	Rev. 1

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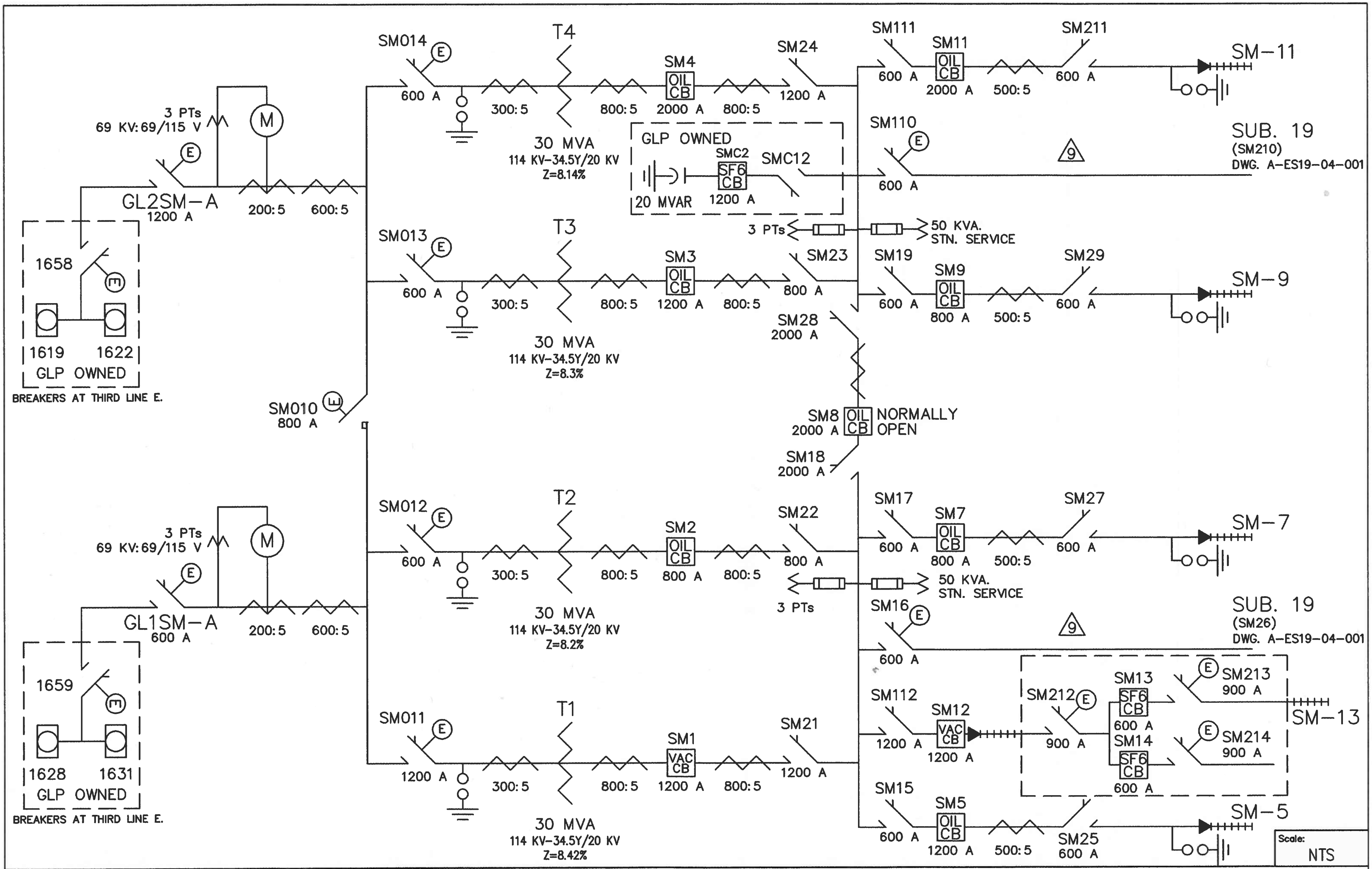

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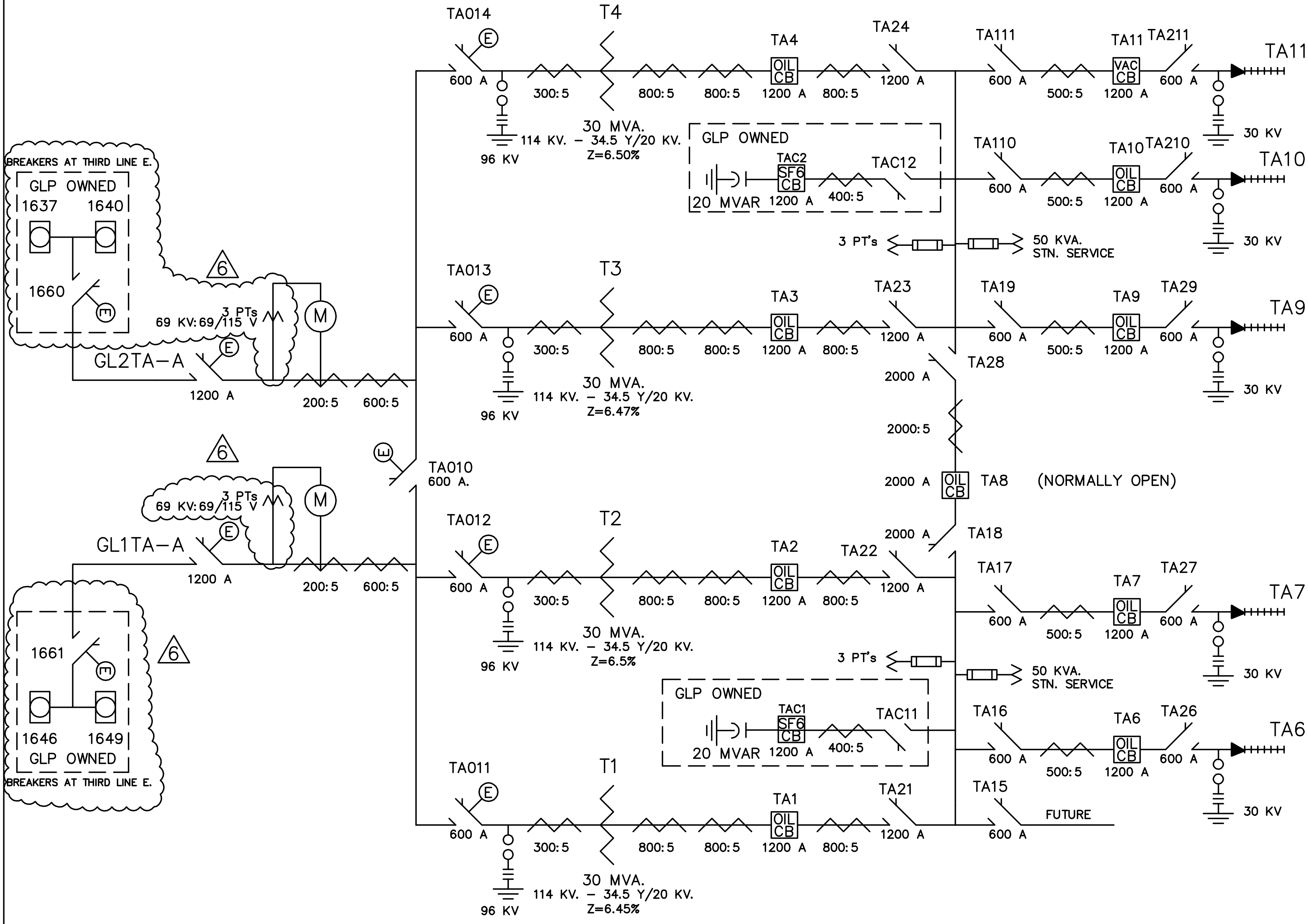
No.	Revision	Date	Initial
9	SUB 19 CONNECTIONS REVISED	JAN. 4/18	J.T.
8	ADDED CBs SM12, SM13 & SM14. REMOVED CB SMC1 & CAP. BANK.	JUL 12/17	J.T.
7	SWITCH REPLACEMENT PROJECT	JUNE 3/13	JFK
6	REVISED GLPT NOMENCLATURE AND ADDED PTs	FEB. 13/13	J.T.
5	REMOVED GROUND SWITCH AND ADDED WHOLESALE METERING	MAY 22/12	J.T.
4	REVISED RATING ON SM21	JUN 23/06	J.T.
3	REVISED RATINGS ON GL2SM-A, SM013, SM24, SM7, SM9 & SM610.	MAY 23/06	J.T.

PUC

TRANSFORMER STATION TS-1

ST. MARY'S TRANSFORMER STATION SCHEMATIC DIAGRAM

Drawn by: J.R.	Date: SEP. 11/86	
Checked by: M.P.	Date: JUL. 12/17	
Approved by:	Date: 2018/01/04	
Drawing Number: A-TS1-04-001		Rev. 9



			Scale: NTS

No.	Revision	Date	Initial
6	REVISED GLPT NOMENCLATURE AND ADDED PTs	FEB. 13/13	J.T.
5	REVISED OIL CIRCUIT BREAKER CT RATIOS	MAY 31/12	J.T.
4	ADDED WHOLESALE METERING	MAY 22/12	J.T.
3	REVISED RATING ON TA15.	JUN 23/06	J.T.
2	REMOVED INCOMER CTs, REVERSED CTs & CBs ON CAP BANKS, ADDED TA15 & REVISED TA21	MAY 23/06	J.T.
1	REVISED DWG. # & RATINGS FOR TAC1, TAC2, TA21, TA22 AND TA24	APR. 18/06	J.T.

PUC

TRANSFORMER STATION TS2

TARENTORUS TRANSFORMER STATION
SCHEMATIC DIAGRAM

Drawn by: J.R.	Date: SEP. 11/86
Checked by: R.H.	Date: FEB. 13/13
Approved by:	Date:
Drawing Number: A-TS2-04-001	Rev. 6

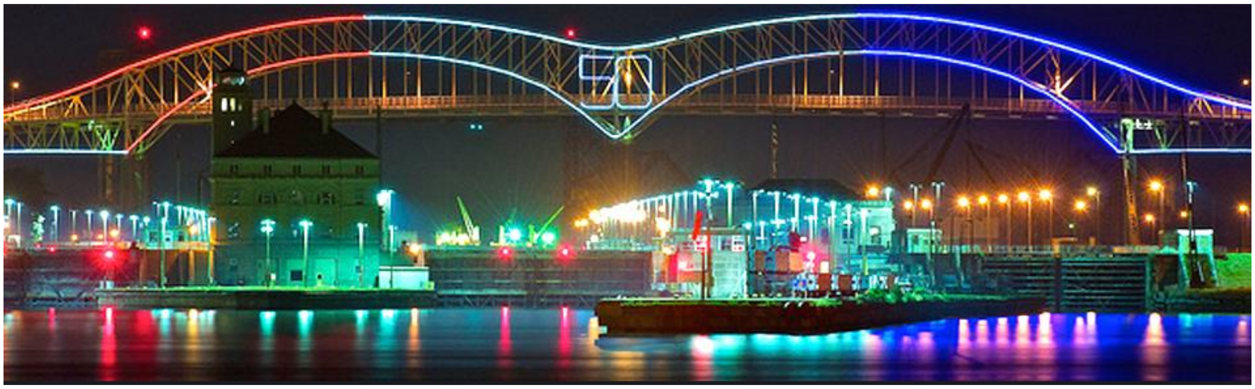
Appendix B

Asset Condition Assessment & Asset Management Plan

Asset Condition Assessment and

Asset Management Plan 2017 – 2021

PUC Distribution Inc.



September 2016

Prepared by

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215-2250 Matheson Blvd East
Mississauga ON L4W 4Z1

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f. 905-232-7405
www.metsco.ca

Contents

List of Figures

EXECUTIVE SUMMARY

This report summarizes the results of the Asset Condition Assessment study performed during the second and third quarter of 2016, by METSCO Energy Solutions Inc. on behalf of PUC DISTRIBUTION Inc. The study was performed with the objective of determining the current condition of fixed assets to identify the assets that present unacceptably high risk of failure in service and develop an investment plan for asset renewal, to mitigate the risk.

Decisions involving investment into fixed assets play a major role in determining the optimal performance of a distribution system. A majority of the investments in fixed assets are triggered by either declining performance in the areas of supply system reliability, power quality or safety; or increasing operating and maintenance costs associated with aging assets. In either case, investments that are either oversized or made too far in advance of the actual system need result in non-optimal operation. On the other hand, investment not made on time when warranted by the system needs raise the risk of performance targets not being achieved and would also result in non-optimal operation. Optimal operation of the distribution system is achieved when "right sized" investments into renewal and replacement are planned and implemented based on a "just-in-time" approach. The risk based Asset Management Strategy, on which this investment plan is based, determines the risk of assets' failure in service, by taking into account assets' service age as well as current asset condition based on test results and inspections.

The study reveals that the power transformers and switchgear employed in PUC DISTRIBUTION's step-down stations present the highest risk of failure in service. As detailed in Section 4.1, out of 39 transformers employed at PUC DISTRIBUTION's stations, 20 have been determined to be in "poor" or "very poor" condition. Station switchgear has also been determined to be in "poor" or "very poor" condition at 14 of the 17 stations, currently supplying PUC's distribution system.

Since the in-service failure of power transformers and switchgear in step-down stations has the largest impact on power supply security and reliability, a long term proactive program is recommended to gradually reconstruct all of the stations, determined to be in poor or very poor condition. In the absence of a proactive plan for renewal, aging infrastructure assets employed at stations and particularly those employed at 115/34.5 kV stations, present an elevated risk of a cascaded equipment failure event, which could potentially lead to a black out of an extended duration and therefore, both of the 115/34.5 kV transformer stations (TS-1 and TS-2) will require rebuild during the next five to ten years. However, to maximize the benefit/cost ratio of this major investment, significant front-end planning and engineering is required to successfully implement the rebuild of these stations. Therefore, we are recommending a planning/engineering study be commissioned to review all practical development options and identify the optimal option for implementation.

For the 34.5 / 12.47 kV stations, we recommend at least two stations be included in the next five-year plan for rebuild, based on the condition of power transformers, switchgear and auxiliary equipment. Although the power transformers and switchgear at each of the three 4 kV distribution stations are also currently in poor and very poor condition, no provision is made in the investment plan for renewal of these stations, as these are recommended to be retired from service.

In case of overhead lines, assets posing a high risk of failure in service can be grouped into three main categories: (a) structurally weak wood poles, (b) copper conductors of #6 AWG cross-section (restricted conductor) and (c) porcelain cut-outs and insulators. Wood poles experience reduction in their structural strength with age, due to a number of factors, including wood rot, termite or wood pecker damage and mechanical damage during storms or vehicular accidents. Poles with reduced strength are identified through non-destructive in-situ testing and when the strength of a pole is determined to fall below its design load, it is identified for replacement. A significant number of overhead lines employ restricted conductors, which have a history of failures in service, due to reduced tensile strength, bringing live conductors down and posing a serious safety risk to public. PUC DISTRIBUTION has been actively rebuilding lines, replacing the restricted conductor during the past five years. This program is recommended to be expedited with the objective of removing all restricted conductor from existing lines during the next 10 years. PUC DISTRIBUTION has been gradually replacing porcelain cut-outs and insulators, which are also known to experience failures in service, during the past five years and this program is scheduled to be completed during 2016. In addition to the above indicated renewal initiatives, some of the existing 4 kV lines will need to be rebuilt through implementation of the voltage upgrade program and some additional lines experiencing high failure rates due to advanced asset age will also require re-construction.

On the underground distribution system, approximately 25% of the cable circuits have reached a service life of greater than 40 years, which is the typical useful life for this type of cable. There are no practical tests available, which could be economically performed in field to accurately assess the remaining useful life of cables, however, cross-linked polyethylene (XLPE) insulated cables generally begin to experience an increase in failure rates when they get past 40-year service age. Therefore, the investment plan includes provision for selectively replacing and rejuvenating cables (through insulation injection where economical) in subdivisions, experiencing high cable failure rates. PUC DISTRIBUTION's underground system employs concrete chambers for various functions, including pre-cast pull-boxes, poured-in-place manholes, concrete vaults and bases for switchgear and K-bar junctions. Approximately 23% of the chambers are currently more than 50 years old. Physical inspections of the concrete structures indicate, a large percentage of these old vintage chambers are functionally obsolete and some are unsafe and will need to be rebuilt. After reconstruction, these vaults should be converted to pads to support pad mounted equipment, mounted above grade. The investment plan also includes provision for replacement of a small number of pad-mounted switchgear and k-bar junction boxes, that are determined to be near the end of their service life.

For distribution transformers, PUC DISTRIBUTION employs a "run-to-failure" strategy and due to the relatively low impact of transformer failures on reliability, this strategy serves well for pole mounted and pad mounted transformers and it is also in line with all other LDCs. However, because vault mounted transformers are not generally replaced with the same type of transformer upon failure, some degree of pre-planning is required to replace these with pad mounted transformers. Therefore, a proactive program is required to replace the submersible transformers with pad mounted transformers.

A vast majority of PUC DISTRIBUTION's electric meters were installed in 2009 and have a seal year of 2019. In order to confirm accuracy of these meters, sample batches of revenue meters will require testing in 2019, in accordance with Measurement Canada's guidelines to acquire an extension of meter seals for 8 more years. To facilitate this, PUC DISTRIBUTION will need to purchase approximately 400 1-phase meters and approximately 50 3-phase meters. In addition to the above, spare revenue meters would be required to replace meters that fail in service.

An estimate of the overall investment level required to implement the asset renewal program recommended in this report is summarized below. The cost estimates were prepared based on 2016 costs and the costs for future years were projected based on annual inflation rate of 2%.

Asset Renewal	**2017**	**2018**	**2019**	**2020**	**2021**	**Five Year Total**
Total Capital Investment Required	$ 4,088,114	$ 8,497,108	$ 4,465,516	$ 4,510,663	$ 9,062,246	$ 30,623,646
Capital Investment Requirement by Excluding Expenditure into Stations	$ 3,862,898	$ 3,940,156	$ 4,018,959	$ 4,099,338	$ 4,181,325	$ 20,102,677

Implementation of the proposed investment plan for asset sustainment would result in an average annual expenditure of $6,124,729.

1 INTRODUCTION

This report summarizes the results of the Asset Condition Assessment study performed by METSCO Energy Solutions Inc. (METSCO) on behalf of PUC DISTRIBUTION Inc. (PUC DISTRIBUTION) during the second and third quarter of 2016. The study was performed with the objective of establishing the health and condition of fixed assets to identify those assets that present unacceptably high risk of failure in service and to develop an investment plan for asset renewal to mitigate the risk.

This report covers the following assets:

a) Power transformers, switchgear, auxiliary equipment, buildings, fences and ground grids employed at Transformer Stations (TS) and Distribution substations
b) Overhead distribution lines;
c) Underground distribution system;
d) Distribution transformers; and
e) Revenue meters.
f) Facilities (office building)

The capital investment plan provided in this report covers the capital expenditure needed for sustainment of existing assets. Expenditure requirements for system growth and new services are not included in this report but these will be included in the Distribution System Plan, based on the anticipated number of requests for new services and load growth.

The report is organized into six (6) sections including this introductory section. Section 2 describes the general principles of the risk based asset management strategy to achieve optimal operation of the distribution grid. Section 3 describes the methodology for ranking and benchmarking the health of assets. Section 4 documents the results of asset condition assessment exercise and Section 5 presents the capital investment plan for renewal and replacement of assets found in poor or very poor condition. Section 6 reviews the preventative maintenance program.

2 STRATEGIC MANAGEMENT OF DISTRIBUTION FIXED ASSETS

Decisions involving investment into fixed assets play a major role in determining the optimal performance of distribution system fixed assets. A majority of the investments in fixed assets are triggered by either declining performance in the areas of supply system reliability, power quality or safety; or increasing operating and maintenance costs associated with aging assets; or anticipated growth in demand requiring capacity upgrades. In either case, investments that are either oversized or made too far in advance of the actual system need may result in non-optimal operation. On the other hand, investment not made on time when warranted by the system needs raise the risk of performance targets not being achieved and would also result in non-optimal operation. Optimal operation of the distribution system is achieved when "right sized" investments into renewal and replacement (capital investments) and into asset repair, rehabilitation and preventative maintenance are planned and implemented based on a "just-in-time" approach. In summary, the overarching objective of the Asset Management Strategy is to find the right balance between capital investments in new infrastructure and operating and maintenance costs so that the combined total cost over the life of the asset is minimized.

A risk based Asset Management Strategy, therefore, determines the risk of assets' failure in service, based on the condition of the assets, which is commonly measured with the help of a yard stick of "Asset Health Indices", and computes the valuation of the risk based on the consequences of assets' failure and identifies the optimal risk mitigation alternative through an evaluation of all available options. Asset management covers the full life cycle of a fixed asset, from preparation of the asset specification and installation standards - to the scope and frequency of preventative maintenance during the asset's service life – and finally to the determination of the assets end-of- life and retirement from service. At each stage of an asset's life cycle, decisions are made to achieve the right balance between achieving maximum life expectancy, highest operating performance, lowest initial investment (capital costs) and lowest operating costs. The best-in-class asset management strategies employ integrated processes that allow optimal levels of financial and operating performance to be achieved, using transparent and objective criteria that can easily be audited and inspected by regulators.

PAS-55, a specification for asset management, was developed by the British Standards Institute (BSI) and offers one of the best-in-class strategies for risk management associated with fixed assets of electricity distribution systems. To be compliant with the PAS-55 asset management standard, the asset management approach must contain the essential elements documented in Figure 2.1.

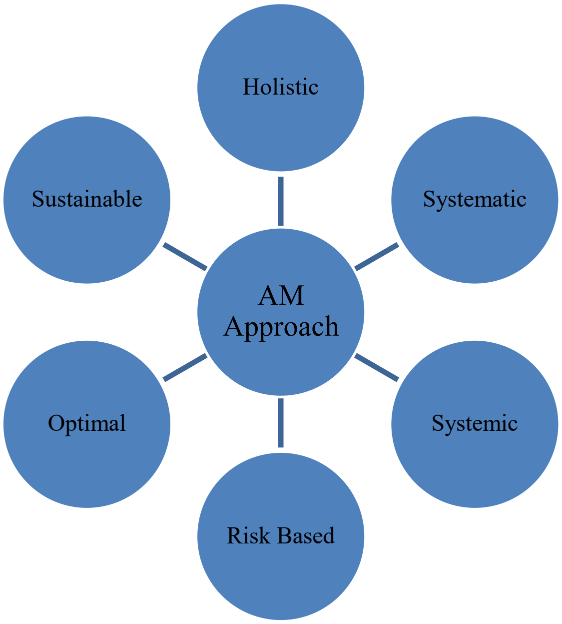

Figure 2-1: Essential Elements of Asset Management Strategy

The overarching objective is to develop capital and preventative maintenance investment plans, which could be implemented over a period of five to ten years to achieve optimal system performance by placing appropriate weights on stakeholder objectives and performance requirements, as shown in Figure 2-2.

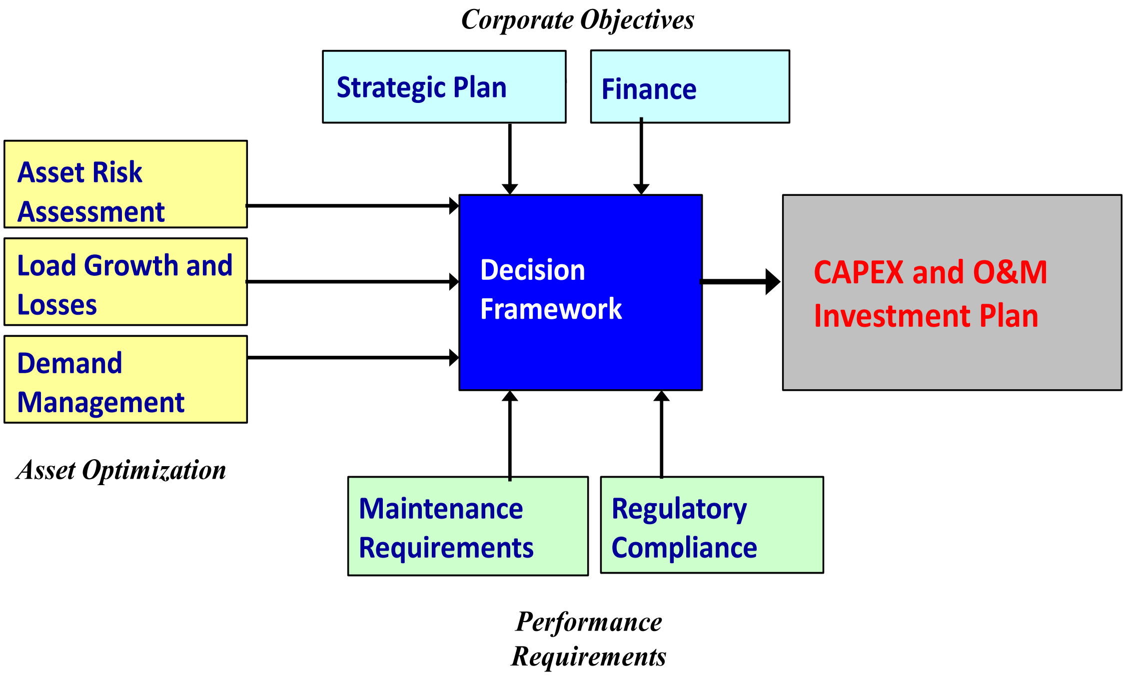

Figure 2-2: Multi-Prong Decision Framework

For regulated transmission and distribution (T&D) businesses, the key considerations in development of a Strategic Asset Management Plan include:

a) Regulatory Compliance
b) Public and Employee Safety
c) Operating Efficiency
d) Reliability and Supply System Security
e) Customer Service Quality
f) Getting Full Life out of Assets
g) Minimizing Asset Life Cycle Costs
h) Minimizing Risk of Premature Failures
i) Minimizing Environmental Risks

Figure 2-3 shows the basic decision support model employed under a risk based strategy. The timing and size of investments are selected to minimize the "Total Cost" of risk and risk mitigation initiatives.

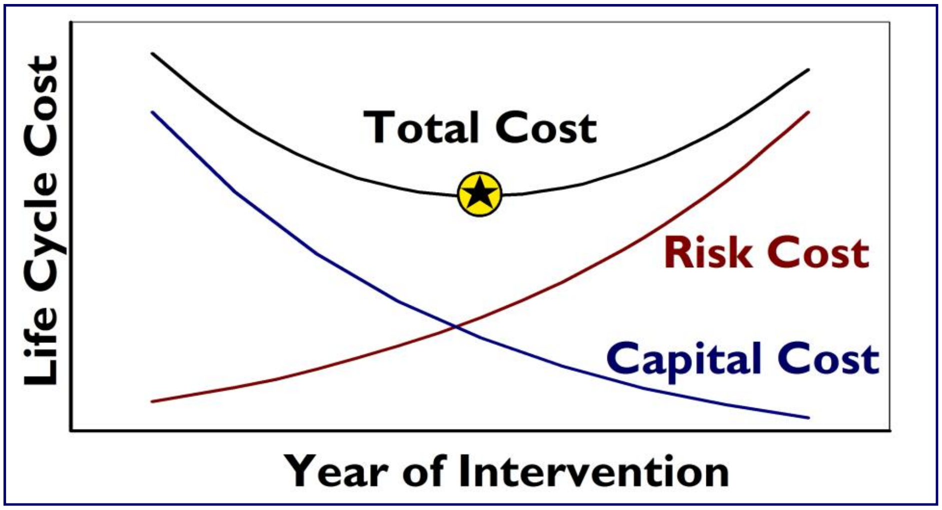

Figure 2-3: Risk Based Decision Support System

Figure 2-4 summarizes a practical matrix to sift through a large number of assets, typically employed on T&D systems to objectively identify assets that present the highest risk of in-service failures so that the investments could be targeted into assets that present the highest risk. Numeric health indices, typically normalized to a scale of 100, are used to express the health and condition of assets, as shown in Figure 2-5 and this allows separation of the assets in good condition that require minimal risk mitigation from those in poor condition, requiring a higher level of investments. This exercise allows development of an investment plan for implementation over a 5 year period.

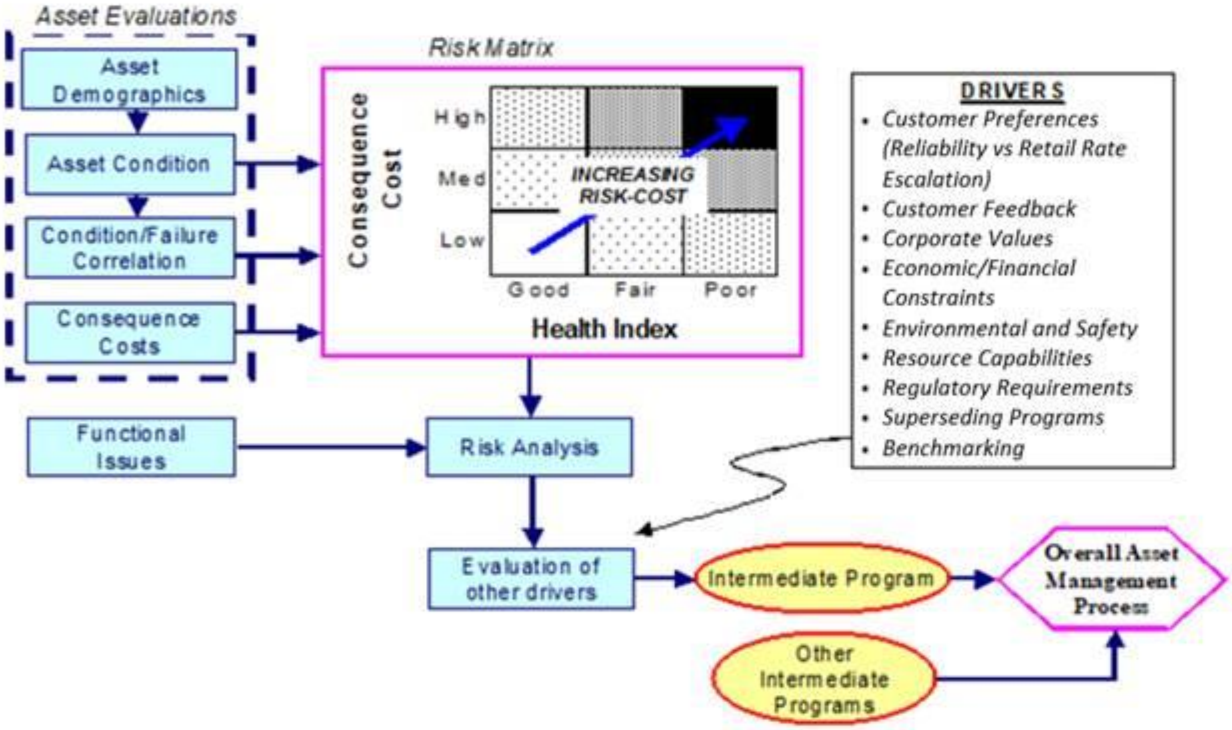

Figure 2-4: Model to Identify Assets with Highest Risks

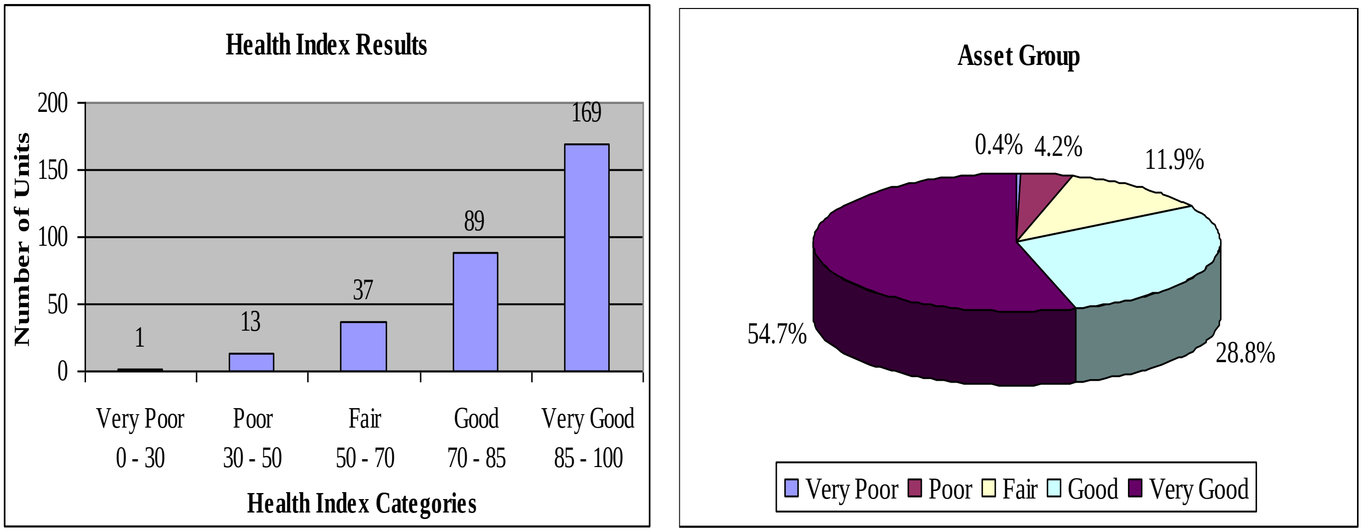

Figure 2-5: Graphs to Identify Assets with Highest Risks

3 ASSET CONDITION ASSESSMENT METHODOLOGY

This section describes in detail an asset condition assessment methodology for different categories of fixed assets employed on the distribution system. Adoption of this methodology would require periodic asset inspections and recording of their condition to identify the assets most at risk, requiring focused investments into risk mitigation.

Asset Condition Assessment methodologies are described below for the following distribution system asset categories:

a) Substations
b) Overhead Lines
c) Underground Lines
d) Distribution Transformers (pole mounted, pad mounted, and submersibles in underground vaults)
e) Distribution Switches and Fused Cut-outs
f) Low Voltage system

Asset health condition indicators and tests shown in the tables are weighted based on their importance in determining the assets end-of-life. For purposes of scoring the condition assessment, the letter condition ratings are assigned the following numbers shown as "factors":

A= 5
B = 4
C = 3
D = 2
E = 1

These condition rating numbers (i.e., A = 5, B = 4, etc.) are multiplied by the assigned weights to compute weighted scores for each component and test. The weighted scores are totaled for each asset. Totaled scores are used in calculating final Health Indices for each asset. For each component, the Health Index calculation involves dividing its total condition score by its maximum condition score, then multiplying by 100. This allows for determining condition category for each asset in groups of "Very Poor", "Poor", "Fair", "Good" and "Very Good" depending upon the resulting score. "Very Good" asset condition represents brand new asset in perfect operating condition. "Good condition" indicates an asset with service life equal to less than 25% of its typical useful life and with no impairment and no noticeable wear. "Fair Condition" indicates an asset with service life equal to more than 25% but less than 80% of its typical useful service life, with normal wear and asset performance within acceptable tolerances and no significant impairment. "Poor Condition" signifies an asset with service life greater than 80% of its typical useful, appreciable wear or significant impairment causing asset performance to degrade below acceptable levels and presenting high risk of asset failure in the absence of major repairs or asset rehabilitation to restore asset condition to "Fair". "Very Poor Condition" signifies an asset with serious impairment to its critical components and presenting very high risk of failure. Assets in "very poor" condition cannot be economically repaired and renewal is the only option to restore their operating condition.

3.1. Substations

The major assets employed in transformer stations and distribution stations include:

- Station Transformers
- Switchgear (Circuit breakers, circuit switchers and reclosers, including protection relays)
- Other assets including station building, fences, ground grids, Bus work, control batteries etc.
- SCADA and Network infrastructure

3.1.1 Condition Assessment Criteria for Station Transformers

The key role of station transformers is to step down transmission or sub-transmission voltage to distribution voltage. PUC DISTRIBUTION has two types of stations: transformer stations and distribution stations. The transformer stations step down from 115 kV to 34.5 kV and the distribution stations step down from 34.5 kV sub-transmission voltages to 12.47 kV or 4.16 kV.

The key components of power transformers installed at transformer and distribution stations include:

- primary and secondary coils, made of copper conductors,
- magnetic core made of low loss iron laminations,
- insulation system, commonly consisting of cellulose paper and mineral oil,
- transformer tank, either sealed or breather type,
- primary and secondary bushings, and
- auxiliary devices.

The most critical component in transformer aging consideration is the insulation system, consisting of mineral oil and cellulose paper. Transformer oil consists of hydrocarbon compounds that degrade with time due to oxidation, resulting in formation of moisture, organic acids and sludge. The oil oxidation rate is a function of operating temperature and degree of contamination with moisture. High operating temperature and presence of moisture content in insulating oil decomposes the insulation to form acids, which causes accelerated degradation of insulation paper. Formation of sludge adversely impacts the cooling efficiency of transformer, resulting in higher operating temperatures and further increasing the rate of oxidation of both the oil and the paper. Condition assessment of transformer oil, through measurement of the dielectric strength, insulation power factor, moisture content, acidity level, and surface tension measurement provides extremely useful information in assessing the health and condition of a transformer.

The paper insulation consists of long cellulose chains, that break up as the paper ages (oxidizes). Tensile strength and ductility of insulation paper are important properties that are determined by the average length of the cellulose chains. As the paper oxidizes, its mechanical strength is gradually reduced, making it weak and brittle. This can lead to sudden insulation failure if the transformer is subjected to a mechanical shock, that are common in normal operating conditions, in form of external faults on lines supplied from the transformer. Insulation degradation and failure can also result from electrical activity inside insulation, such as partial discharge activity, which is initiated if the level of moisture in oil builds up or if other minor defects develop within the insulation. Service age and operating temperature during the service life also provide indication of the condition of insulation system in transformers. Power transformers are known to typically provide a service life of approximately 40 to 45 years.

Partial discharge and other electrical and thermal faults in the transformer can be detected and monitored by measurement of hydrocarbon gases in the oil through Dissolved Gas Analysis (DGA).

Computing the Health Index for a transformer requires developing end-of-life criteria for its various components. Each criterion represents a factor critical in determining the component's condition relative to potential failure. The condition assessment process includes scoring based on multiple parameter criteria as described below:

(a) **Age Related Scoring**

Since the service age provides a reasonably good measure of the remaining life of transformers, it is employed as an assessment parameter, with the following scores:

Table 3-1: Station Transformers – Age Related Health Score

Condition Rating	Station Transformer Age
A	0 to 10 years
B	11 to 20 years
C	21 to 35 years
D	36 to 50 years
E	Older than 50 years

(b) Scoring Based on Loading Level:

The rate of insulation degradation is directly related to the operating temperature and operating temperature is directly related to loading levels. Peak loading level of the transformers expressed in % of nameplate rating can therefore be employed as an indicator of transformer health:

Table 3-2: Station Transformers – Load Related Health Score

Condition Rating	Component Condition
A	Peak load less than 50% of its rating
B	Peak load of 51% to 70% of its rating
C	Peak load of 71% to 85% of its rating
D	Peak load of 86% to 100% of its rating
E	Peak load of greater than 100% of its rating

(c) Scoring Based on Visual Inspections

Visual inspections can provide a good indication of the physical condition of transformers, which can be ranked as indicated below:

Table 3-3: Station Transformers – Health Score Based on Visual Inspections

Condition Rating	Visual Inspections

A	No rust on tank/radiator, no damage to bushings, no sign of oil leaks, forced air cooling fully functional
B	Only one of the following defects: Minor rust, or minor cracks in bushings or minor oil leak
C	Two or more of the above indicated defects present but do not impact safe operation
D	Tank or radiator badly rusted or damage to bushing or significant oil leak
E	Two or more of the above indicated defects or the cooling fans do not work

(d) Scoring Based on Testing of the Insulating Oil

Various insulation tests, including dissolved gas in oil analysis (DGA), dielectric strength or water content measurement test can be interpreted by an expert to rank the overall condition of transformer insulation system:

Table 3-4: Station Transformers – Health Score Based on Oil Tests

Condition Rating	Test Results
A	Test results indicate excellent insulation condition, no indication of moisture, arcing, overheating or degradation of paper
B	Tests indicate normal aging, no concerns about insulation health
C	Tests indicate slightly above average but stable moisture content or presence of arcing overheating related gases
D	Some of the tests indicates significant concerns about insulation condition
E	Two or more of the tests indicate rapidly deteriorating insulation condition

3.1.2 Condition Assessment Criteria for Substation Switchgear

High voltage or medium voltage circuit breakers provide local or remote control for closing and opening of power supply circuits and in conjunction with protective relays provide an important safety function to automatically detect and isolate faulty circuits in order to provide safe, stable and reliable operation with desired selectivity. While its design is significantly different, the recloser employs the same operating principle as a circuit breaker. In case of low short circuit levels, circuit switchers are used in lieu of circuit breakers to provide the same function.

When a circuit breaker interrupts current, an electrical arc is produced in the ionized insulation medium. In order for the circuit breaker action to succeed, the large amount of energy contained in the arc must be successfully extinguished by the breaker's interrupting medium. Depending on the type of arc interrupting medium employed, circuit breakers (or reclosers) are classified as oil circuit breakers, magnetic air circuit breakers, SF-6 circuit breakers or vacuum circuit breakers. In order to deliver the desired functions, circuit breakers and reclosers are required to possess the following properties and characteristics:

- Highly conductive contact material, capable of withstanding repeated arcs;
- High quality of contact make with extremely low resistance;
- Adequate contacts parting distance in open position for the rated voltage;
- Adequate line to ground insulation for the rated voltage;
- Stable insulating medium, capable of withstanding repeated arcs;
- Fast speed during opening and closing of contacts;
- Appropriate arc blowing techniques to extinguish arcs;
- Adequate energy imparting mechanisms for making or breaking of short circuit currents.

The operating mechanism of circuit breakers and reclosers consists of numerous moving parts that are subject to wear and tear during breaker operation. Because circuit breakers are required to frequently "make" and "break" heavy currents, the contacts are subjected to arcing that accompanies such operations. Each time a circuit breaker opens or closes, the contact surfaces undergo some degradation and degraded contacts produces higher degree of arcing in subsequent operations. Heat produced during contact arcing also decomposes the metal surface from the contacts as well as the insulation medium and the by-products so decomposed are deposited in surrounding insulation materials. The mechanical energy required to generate high contact velocities also results in wear and tear of the mechanical parts in operating mechanism.

A number of factors influence the overall rate of wear and severity of degradation of circuit breakers, including type of the insulating medium, design of the contacts, operating environment, and the duty cycle of the circuit breaker. Load current switching or fault current interruption seldom lead to sudden failure of circuit breakers, but repeated operations result in overall wear and tear which lead to eventual end of life.

Circuit breakers mounted outdoors may experience adverse environmental conditions that may further contribute to the rate and severity of degradation. The following factors represent environmental degradation of outdoor mounted circuit breakers:

- Corrosion of enclosures and metal parts;
- Potential ingress of moisture into operating parts and insulating system;
- Bushing/insulator deterioration under the influence of moisture, fog, ice; and
- Deterioration of mechanical parts;

Oil Circuit Breakers (OCBs) typically have longer current interruption duration compared with other types of designs. Contacts and the insulation medium are therefore subjected to severe arcing, resulting in deterioration of the contact surface as well as insulation. Thus, both contacts and oil degrade more rapidly in case of OCBs than they do in either SF6 or vacuum designs, especially when the OCB undergoes frequent switching operations. Generally, 4 to 8 interruptions under fault or heavy load will cause contact erosion and oil carbonisation, requiring contact maintenance and possibly oil filtration. OCBs have therefore higher operating costs compared to other designs.

Different types of circuit breakers employed on PUC DISTRIBUTION's transformer and distribution stations are described below:

(i) Oil Circuit Breakers (OCB) or Oil Filled Reclosers

In minimum oil circuit breakers, insulating oil provides the role of arc quenching only, but in bulk oil circuit breakers, the insulating oil provides both the arc quenching and the insulation functions. OCBs generally perform well at low ambient temperatures. They also provide long and reliable service life when the number of loading switching or fault interruption operations is infrequent. However, frequent switching fault interruption applications must be accompanied by frequent preventative maintenance. OCBs do not perform well in switching capacitive loads, during switching operations of which high peak recovery voltages are produced.. The manufacture of new OCBs has been discontinued for at least 30 years now. The original equipment manufacturers (OEMs) provided service support and spares for these OCBs until the late 1990s. Many utilities in North America continue to successfully employ older vintages of OCBs on their systems.

(ii) Air Magnetic Circuit Breakers (Air Magnetic Breakers)

Air magnetic breakers employ the magnetic effect of the current in their design, by forcing the electric arc produced during opening on the contacts into an arc chute. The arc chute causes elongation of the arc path and allows cooling, splitting and eventual extinction of the arc. In some designs, an auxiliary puffer is employed to blast air into the arc, which allows successful interruption of low-level currents with weaker magnetic fields. Air magnetic breakers represent the second oldest technology in circuit breaker design, next to OCBs. They are also no longer in manufacture and have been superseded by SF6 and vacuum technologies since the late 1970s.

(iii) Vacuum Circuit Breakers or Reclosers

In a vacuum circuit breaker, vacuum interrupters are employed to make or break load or fault current. Upon separation of the contacts, the current initiates a metal vapour arc discharge and flows through the plasma until the next current zero. The arc is extinguished at current zero and the conductive metal vapour condenses on the metal surfaces during a very short time interval measured in micro seconds. Therefore, the dielectric strength in the breaker builds up very rapidly. The effectiveness of vacuum interrupter depends largely on the material and form of the contacts. In modern designs, oxygen free copper chromium alloy is commonly employed as it is believed to be the best material for the application. This material combines good arc extinguishing characteristic with a reduced tendency to contact welding.

(iv) SF_6 Circuit Breakers

A SF_6 circuit breaker is designed to direct a constant gas flow to the arc that extracts heat from the arc and so allows achieving its extinction at current zero. The gas flow de-ionises the contact gap and establishes the required dielectric strength to prevent an arc re-strike. The direction of the gas flow either parallel or across to the axis of the arc has an influence on the efficiency of the arc interruption process. Research has shown that an axial flow creates a turbulence causing an intensive and continuous interaction between the gas and plasma as current approaches zero. Recent developments concentrated on employing the arc energy itself to create directly the differential pressure needed, without using an external piston. Parallel to the self-pressurising design, the rotating arc SF_6 interrupter was also developed. In this design, a coil sets the arc in rotation while the quenching medium remains stationary. The relative movement between the arc and the gas is no longer axial but radial; it is a cross-flow mechanism.

Computing the Health Index for circuit breakers requires collection of data on a number of condition indicators:

(a) Age Related Scoring

Service age provides a reasonably good measure of the remaining life of circuit breakers and reclosers. Since the outdoor mounted reclosers, exposed to the weather elements experience a faster rate of aging, two separate sets of criteria are provided for outdoor and indoor mounted circuit breakers / reclosers:

Table 3-5: Outdoor Circuit Breakers or Reclosers – Age Related Health Score

Condition Rating	Age
A	0 to 7 years
B	8 to 15 years
C	16 to 30 years
D	31 to 35 years
E	35 years or older

Table 3-6: Indoor Circuit Breakers – Age Related Health Score

Condition Rating	Age
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years (or
D	31 to 40 years
E	41 years or older

(b) Scoring based on Visual Inspections

Visual inspections can provide a good indication of the physical condition of circuit breakers or reclosers, which can be ranked as indicated below:

Table 3-7: Circuit Breakers – Visual Inspections Based Health Score

Condition Rating	Visual Inspection Indicators
A	No rust on tank/enclosure, no damage to bushings, no leaks, controls and wiring in excellent condition
B	Only one of the following defects: Minor rust, or minor cracks in bushings or minor oil leak
C	Two or more of the above indicated defects present but do not impact safe operation

D	Tank/enclosure badly rusted or major damage to bushing or major oil leak
E	Two or more of the above indicated defects or the cooling fans do not work

(c) Scoring Based on Evaluation of the tests

Various interruption chamber tests can be interpreted by an expert to rank the overall condition of breaker insulation system:

Table 3-8: Circuit Breakers and Recloser – Testing Based Health Score

Condition Rating	Test Results
A	Test results indicate excellent condition of contacts, operating mechanism, insulation condition and controls
B	Normal aging, each of the four indicators, identified in A above, within specified limits
C	One of the above four indicators is slightly beyond the specified limits
D	Two or more of the above four indicators beyond the specified limits
E	Two or more of the indicators beyond specifications and cannot be brought to comply with the specifications

(d) Scoring Based on Condition of the protection relay calibration tests

Calibration tests can be interpreted by an expert to rank the overall condition of protection relays:

Table 3-9: Protection Relays – Testing Based Health Score

Condition Rating	Test Results
A	Excellent operating condition, calibration well within specified limits
B	Normal aging, calibration within the specified limits
C	Frequent calibration required, but it is possible to meet specified limits
E	Not possible to calibrate the relays to bring settings to specified limits

3.1.3 Condition Assessment Criteria of Other Key Substation Assets

a) Ground Grids

The purpose of a substation ground grid is to provide a low resistance ground electrode for system neutral, for equipment case grounding and to maintain safe potential gradients within the station yards during abnormal operating conditions, i.e. line-to-ground faults.

The station ground electrode consist of multiple ground rods driven into the ground and located strategically and connected with underground copper conductors to make a mesh of sufficiently low resistance. All feeder neutrals are connected to the electrode. Cases of each piece of power equipment are also bonded to the ground electrode. All fences and gates are bonded to the perimeter ground grid.

Where the ground potential rise (GPR) exceeds safe limits, surface stone of high resistivity is used in the substation yard to maintain step potential within safe limits.

Buried ground rods, conductors and connectors are subject to corrosion, which reduces the effectiveness of the ground electrode with passage of time. Above ground components of the electrode and copper conductors are subject to vandalism and damage. The surface stone can degrade in quality due to growth of weeds.

i. Ground Grid Condition Rating Based on Evaluation of the tests

Table 3-10: Ground Grid – Testing Related Health Score

Condition Rating	Test Results
A	Ground electrode resistance and GPR within safe limits, all electrode components pass integrity test
C	Ground electrode resistance and GPR within safe limits but a few electrode components do not pass integrity test
E	Ground electrode resistance or GPR not within safe limits or many electrode components do not pass integrity test

ii. Rating Based on Condition of Surface Stone

Table 3-11: Ground Grid – Surface Stone Health Score

Condition Rating	Test/Inspection Results
A	Resistivity of Surface Stone >3000 Ohm-m, no sign of vegetation growth
C	Resistivity of Surface Stone marginally less than <3000 Ohm-m, but no sign of vegetation growth
E	Resistivity of Surface Stone significantly less than <3000 Ohm-m, and signs of vegetation growth

b) Substation Fences

The purpose of substation fences is to provide security for substation assets by not allowing entry into the yard to unauthorized people or wild life. To achieve this objective the fence has to be of a minimum height of 1.8 m to comply with the Ontario Electrical Safety Code and topped with three rungs of barbed wire covering a height of 0.3 m. The fence must be secured with posts of adequate strength and should limit the crawl space between the fence and ground to 0.1 m or less. Where a substation fence connects into another steel fence, an insulated section should be added to prevent transfer of harmful potential to remote locations. The fence should be grounded and bonded throughout. The gates should be lockable and locked and warning signs should be provided.

The common degradation mode for station fences are rusting and corrosion, damage to fence posts and gates, soil erosion increasing the crawl space under the fence and vandalism to damage and deface warning signs. The following criteria is recommended for condition assessment of station fences:

Table 3-12: Ground Grid – Fences Health Score based on Visual Inspections

Condition Rating	Inspections
A	No deficiencies in the fence
C	Only minor deficiencies
E	Major deficiencies requiring immediate attention

c) Substation Buildings

Substation buildings provide protection to critical substation assets, i.e. circuit breakers and protection relays against weather elements. While the switchgear is commonly located on the main floor, the basements serve as an oversized manhole to provide exit for feeder cables.

The common degradation mode for substation buildings is deterioration of roofs, sidings, doors and windows. A small leak in the roof can cause a lot of harm to electrical equipment and defeat the very purpose of the substation building.

The health and condition of a substation building can be measured through visual inspections:

Table 3-13: Substation Buildings Health Score

Condition Rating	Inspections
A	No deficiencies in the building
C	Only minor deficiencies
E	Major deficiencies requiring immediate attention

3.1.4 Health Index Formulation for Substation Equipment

Since each piece of substation equipment can be independently replaced or rehabilitated, rather than developing an overall health index for substations, methodology for developing health indices for key substation assets is provided below:

For purposes of formulating the Health Index for major substation assets, it is proposed to assign the following weights to various health index criteria described in the previous sections:

Table 3-14: Station Transformers – Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age of transformer	A - E	5	6	30
2	Peak loading	A - E	5	4	20
3	Visual inspection	A - E	5	2	10
4	Testing	A - E	5	8	40
	Total				100

Table 3-15: Station Switchgear (Circuit breaker / Recloser) Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age	A - E	5	6	30
2	Visual inspection	A - E	5	4	20
3	Breaker Testing	A - E	5	6	30
4	Protection Relay Testing	A - E	5	4	20
	Total				100

Table 3-16: Other Station Asset Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Ground Grid	A - E	5	8	40
2	Surface Stone	A - E	5	8	20
3	Fences	A - E	5	4	20
4	Buildings	A - E	5	4	20
	Total				100

3.2. Overhead Lines

Condition assessment methodologies for the following components employed on overhead lines are discussed below:

- Poles
- Insulators
- Hardware
- Conductors and splices

3.2.1. Condition Assessment Criteria for Poles, Insulators and Pole Hardware:

a) Poles:

As wood is a natural material, its degradation processes are different from other assets on distribution systems. The most critical degradation process for wood poles involves biological and environmental mechanisms such as fungal decay, wildlife damage and effects of weather. Fungi attack both external surfaces and the internal heartwood of wood poles. The process of fungal decay requires the presence of fungus spores in the presence of water and oxygen. For this reason, the area of the pole most susceptible to fungal decay is at and around the ground line, although pole rot is also known to begin at the top of the pole. To prevent the decay of wood poles, utilities treat them with preservatives before installation. Wood preservatives have two basic functions:

- keep out moisture that supports fungi by sealing the surfaces, and
- kill off the fungal spores.

Most power companies install only fully treated wood poles these days, however this was not always the case and the lines constructed 40 years ago or earlier may not have been constructed with fully treated poles but only butt treated poles may have been used. Typically, fully treated poles are expected to provide a longer service life in relation to butt treated poles.

The following factors represent some of the more critical factors affecting wood pole strength as poles age:

- Original type and class of wood pole;
- Original defects in wood (e.g. knots, cracks or rot);
- Rate of decay in service life which depends on type of treatment and environmental conditions;
- Pole damage by woodpeckers, insects, and other wildlife; and
- Wood burns.

Several types of damage can also deform bolt holes in poles. Generally, such deformities do not present immediate problems. However, in some cases deformed holes can result in both failure of the structure and failure of other components attached to the pole. Bolts also can become loose, elongated, bent, cracked, sheared/broken and lost.

Visual inspection can detect the following types of wood pole damage readily:

- Fibre damage that may occur when wind hits a wood pole with force beyond the pole's bearing capacity;
- Partial damage that may result when objects hit wood poles and reduce effective pole circumference. If the damage affects only part of a pole's cross-section the utility may keep the pole in service with a reduced factor of safety.
- Wood splits from various causes that may accelerate the end of a pole's life, depending upon the extent of the split damage;
- Mis-orientation from excessive transverse forces that may result in pole tilting as well as "stretching" (i.e., loosening) and breaking of guys and guying systems;
- Burning from conductor faults and insulator flashovers that may damage wood poles, wooden support cross-braces and timber, reducing the ability of these structures to withstand mechanical stress changes or causing their complete loss through fire; and
- Wood cracks that may hold moisture and cause decay or weaken the structures through freeze/thaw forces during winter.

Utilities have sought objective and accurate means to assess pole condition and remaining life, as a result of which, a wide range of wood pole assessment and diagnostic tools and techniques has developed. These include techniques designed to apply traditional probing and hammer tests in more controlled, repeatable and objective ways. Indirect and non-destructive techniques such as ultrasonics, X-rays, and electrical resistance have received widespread testing.

b) Condition Assessment Criteria for Insulators

The types of insulators and configurations typically used in distribution systems include dead-end, suspension, post and pin types. The insulating portion may consist of porcelain or polymer. The metallic parts usually are made from zinc coated ductile or malleable iron. Both electrical and mechanical stresses may affect insulators. Degradation and eventual failure generally result from the loss of either dielectric or mechanical strength. Mechanical loading on suspension and line post insulators consists of a combination of tensile, torsional, cantilever, vibration and compression forces resulting from factors such as conductor vibration and galloping, accumulation of high density snow or ice, and sudden ice shedding. Line post, strut and pin type insulators are unique since they may experience a combination of cantilever, transverse and tensile forces simultaneously. Impact or contact induced damage also may occur.

Contamination of insulator surface with road salt, freezing rain, and snow accumulation may induce flashovers resulting in dielectric failure of insulators. Electrical flashovers can cause both external and internal damage to porcelain and composite insulators. Visual inspection can detect the following external insulator damage readily:

- Broken porcelain from the shell caused by a flashover (lightning) or impact damage (vandalism);
- Flashover burn markings on the porcelain shell resulting from burns/arcing damage/galvanizing;

Latent damages, typically internal to the porcelain shell, metal fitting and hardware include:

- Internal cracks under the metal cap or inside the porcelain head from lightning flashovers or line galloping, which in essence cause electrical shorts in the insulator that can distort the insulator string's voltage profile;
- Radial cracks (come from cement growth) through the porcelain shell;

Composite insulators consist of a glass fibre reinforced rod covered in either EPDM or silicone rubber weather sheds with appropriate end fittings. While the composite insulators offer a great range of mechanical strengths and much lower weight than other types of insulators, the EPDM or silicone rubber material also is soft and easily cut, ripped or punctured by sharp objects. The integrity of the sheath and weather sheds is critical. Failure commonly occurs when moisture enters into the glass fibre rod area.

Noticeable damage to insulator includes cuts, splits, holes, erosion, tracking, or burning of the rubber shed and sheath material, plus separation or degradation of the rubber sheath material where it meets the metal end fittings. Any signs of power arc, lightning damage, or corrosion on the metal end fittings also indicate deterioration of the component.

c) Condition Assessment Criteria for Metal Cross Arms or Hardware

Degradation or reduction in strength of insulator hardware may occur due to the following:

- Loss of galvanization and corrosion of steel members;
- Loss in strength due to fatigue;
- Loosening of hardware due to conductor vibrations; or
- Hardware failure during major storm events.

Close-up visual inspections generally can determine the extent of degradation. Laboratory testing can further corroborate results of visual investigations.

3.2.2. Ranking Condition of Poles, Insulators and Pole Hardware

The condition assessment process includes scoring based on multiple parameter criteria as described below:

a) Age Related Score:

Since the service age provides a reasonably good measure of the remaining strength of wood poles, cross arms, hardware and insulators, it is employed as an assessment parameter, with the following scores:

Table 3-17: Overhead Lines – Age Related Health Score

Condition Rating	Age
A	0 to 10 years
B	11 to 30 years
C	31 to 40 years
D	41 to 60 years
E	Older than 60 years

b) Scoring Based on Preservative Treatment of Wood Poles

Since the rate of pole degradation is affected by the effectiveness of the preservative treatment, wood pole treatment is employed in Health Index formulation of line sections, as indicated in the table below:

Table 3-18: Overhead Lines – Pole Treatment Based Health Score

Condition Rating	Type of Pole Treatment
A	Fully Treated
C	Butt Treated
E	No Treatment

c) Condition Rating Based on Visual Examinations of Pole Line Components

Different components of the pole line, including wood poles, cross-arms, hardware, insulators and pole grounding are visually inspected by qualified staff during line patrols. By taking into account the results of these inspections, the health and condition of each component is scored in accordance with the following table:

Table 3-19: Overhead Lines – Visual Inspections Based Health Score

Condition Rating	Component Condition
A	Component is in "as new" condition
B	Component has normal wear expected with age
C	Component has many minor problems or a major problem that requires close attention and monitoring
D	Component has many problems and the potential for its failure would rapidly escalate unless preventative maintenance is performed
E	Component has damaged/degraded beyond repair and will require replacement

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3.2.3. Condition Assessment Criteria for Conductors

a) Condition Assessment Criteria for Line Conductors:

Conductors allow flow of current through them facilitating the movement of power from substations to customers' premises. Overhead line conductors are typically supported on wood pole structures to which they are attached by insulators suitable for the voltage at which the lines operate. The conductors on a line are sized by taking into account the amount of current to be carried. The maximum current carrying capacity of conductors is determined by their thermal rating. However distribution line conductors are commonly sized to provide the right balance between energy loss in conductors (copper loss) and the capital cost of conductors. As a result the distribution lines often operate under loads significantly below the thermal rating of the conductors.

Overhead line conductors must have adequate tensile strength, enabling them to be stretched between poles. Distribution lines typically have span length of 40 m to 60 m. Three different types of conductors are commonly used on distribution lines:

- Aluminium Conductors Steel Reinforced (ACSR),
- Aluminium Stranded Conductors (ASC),
- Aluminium Alloy Conductors (AAC).

Steel reinforced aluminium conductors have galvanized steel core strands that supply most of their tensile strength. The steel core has both tensile and ductile properties, allowing the core to withstand both longitudinal forces and bending movements without failure. AAC conductors cost less in relation to ACSR conductors, but their tensile strength is significantly lower than those of the ACSR conductors. Both the price and tensile strength of AAC conductors lie in between those of ASC and ACSR conductors.

As current passes through the conductors, the resistance causes its temperature to rise, the temperature change is proportional to the square of the load current passing through the conductor. The rise in temperature causes the conductor to lengthen and sag between points of support, reducing the height of the conductor above ground. Although it seldom happens on distribution lines, line operation at loads beyond conductors' thermal rating of approximately 90° C may lead to annealing of conductors, resulting in permanent loss of its tensile strength.

To provide their intended functions on distribution lines, conductors must retain both their conductive properties and mechanical (i.e., tensile) strength. Aluminium conductors have three primary modes of degradation; corrosion, fatigue and creep. The rate of each degradation mode depends on several factors, including the size and construction of the conductor as well as environmental and operating conditions.

Generally, corrosion represents the most critical life-limiting factor for ACSR conductors. Environmental conditions affect degradation rates from corrosion. Both aluminium and zinc-coated steel core conductors are susceptible to corrosion from chlorine-based pollutants, even in low concentrations, but the rate of corrosion of steel core is significantly greater than that of aluminium. While fatigue degradation is a serious concern for transmission lines that are strung with significantly higher tension, it is commonly not a serious issue for distribution lines.

Overloaded lines operating beyond their thermal capacity can suffer from a loss of tensile strength due to annealing at elevated operating temperatures. Each elevated temperature event adds cumulative damage to the conductors. After loss of 10% of a conductor's rated tensile strength, significant sag occurs, requiring either re-sagging or replacement of the conductor. ACSR conductors can withstand greater annealing degradation compared to ASC.

Phase to phase power arcs can result from conductor galloping during severe storm events. This can cause localized burning and melting of a conductor's aluminium strands, reducing strength at those sites and potentially leading to conductor failures.

Other forms of conductor damage include:

- Broken strands (i.e., outer and inners)
- Strand abrasion
- Elongation (i.e., change in sags and tensions)
- Burn damage (i.e., power arc/clashing)
- Bird-caging.

On distribution lines, constructed to CSA standards, it is rare for conductors on entire line sections to experience degradations described above. Although laboratory tests are available to determine the degree of corrosion and assess the tensile strength and remaining useful life of conductors, distribution line conductors rarely require testing. Conductors on distribution lines often outlive the poles and are not usually on the critical path to determine end of life for a line section.

The only exception to the above rule might be where small copper conductors susceptible to frequent breakdowns are in use or where line conductors are too small for line loads resulting in sub optimal system operation due to high line loss.

b) Condition Assessment Criteria for Splices

Conductor splices generally have a larger cross-sectional area than the conductor itself. When properly installed, splices should outlast the conductor. However, when improperly installed, splices can reduce a conductor's life. Improperly crimped splices represent the weakest link in conductors under tension.

In extreme cases, splice failures lead to excessive conductor annealing that may cause the conductor's strands to be pulled from the compression splice. Any strand damage that occurs during splice installation may lead to localized weakening of the conductor and premature splice failure. Failure to use non-oxidizing grease in splices also may lead to the development of hot spots and splice failure.

3.2.4. Ranking Condition of Conductors and Splices through Multiple Criteria

Computing the Health Index for overhead line conductors and splices requires developing end-of-life criteria for conductors. The condition assessment process includes scoring based on the risk of conductors breaking and falling.

Since small sized conductors pose a serious safety risk, the value of this risk is scored separately with help of the table below:

Table 3-20: Overhead Lines - Small Conductor Related Health Score

Condition Rating	Age
A	Absence of small sized conductors
E	Presence of small sized conductors (#4 to #6 copper)

3.2.5. Health Index Formulation for Overhead Lines

Health indexing quantifies equipment conditions relative to long-term degradation factors that cumulatively lead to an asset's end-of-life. Health indexing differs from maintenance testing, which emphasizes finding defects and deficiencies that need correction or remediation to keep the asset operating during some time period.

For purposes of formulating the Health Index for overhead line sections, it is proposed to assign the following weights to various Health Index criteria described in Section 3.2.1 through 3.2.4.

Table 3-21: Overhead Lines Health Index Algorithm

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age of pole line	A - E	5	3	15
2	Pole treatment	A - E	5	1	5
3	Visual inspection of poles	A - E	5	1	5
4	Pole testing	A - E	5	4	20
5	Visual inspection of insulators	A - E	5	1	5
6	Visual inspection of hardware	A - E	5	1	5
7	Small conductor risk	A - E	5	5	25
	Total				80

3.3. *Underground Distribution System*

The major assets employed on underground distribution systems can be grouped into the following categories:

- Cables, splices and terminations
- Manholes and vaults

3.3.1. Condition Assessment Criteria for Cables, Splices and Terminations

Safety, reliability, aesthetics and operating costs govern the design and construction standards for underground distribution lines. Underground cables can be constructed in a number of configurations, including direct buried cables, cables installed in direct buried conduits and cables installed in a concrete encased duct manhole system. Medium voltage underground cables have the following key components:

- Cables
- Cable Splices
- Cable Terminations

a) Cables

Medium voltage cables may employ either copper or aluminium conductors. They may be constructed in either single phase or three phase configurations. Two major types of cables are in common use in Canada: paper insulated lead covered (PILC) and cross linked polyethylene (XLPE).

Polymer insulations for cables were introduced as an economic alternative to PILC cables in 1970's. The insulation system in these cables consists of a semi-conducting sheath over the conductor, the insulation, another semi-conducting layer over the insulation, a metallic shield tape or concentric neutral and a jacket. For the early generation of these cables, manufactured in the 1970's, two unexpected factors entered into the failure mechanism: presence of impurities in the insulation system and ingress of moisture that made these cables susceptible to premature failures due to water treeing. Corrosion of concentric neutral conductors is another potential mode of failure. Water treeing is the most significant degradation process for polymeric cables. The original design of cables with polymeric sheaths allowed water to penetrate and come into contact with the insulation. In the presence of electric fields water migration can result in treeing and ultimately breakdown. The rate of growth of water trees is dependent on the quality of the polymeric insulation and the manufacturing process. Any contamination voids or discontinuities will accelerate degradation. This has been the reason for poor reliability and relatively short lifetimes of early polymeric cables.

As manufacturing processes have improved the performance and ultimate life of this type of cable has also improved. In addition to manufacturing improvements, development of tree retardant TRXLPE cables and designs to incorporate metal foil barriers and water migration control have further reduced the rate of deterioration due to treeing.

Distribution underground cables are one of the more challenging assets on electricity systems from a condition assessment and asset management viewpoint. Although a number of test techniques, such as partial discharge (PD) testing have become available over the recent years, it is still very difficult and expensive to obtain accurate condition information for buried cables. The standard approach to managing cable systems has been monitoring of cable failure rates and the impacts of in-service failures on reliability and operating costs and when the costs associated with in-service failures, including the cost of repeated emergency repairs and customer outage costs become higher than the annualized cost of cable replacement, the cables are replaced.

b) Cable Splices and Terminations

Cable splices and terminations are subject to the same type of insulation degradation and aging as the cables themselves. Improperly made splices may be susceptible to moisture ingress and as a result may experience higher failure rates compared to cables.

3.3.2. Ranking Condition of Cables and Splices through Multiple Criteria

Computing the Health Index for an underground cable section requires developing end-of-life criteria for its various components. The condition assessment process includes scoring based on multiple parameter criteria as described below:

(a) Age Related Scoring

Since the service age provides a reasonably good measure of the remaining useful life of cables, splices and terminations, it can be employed as an assessment parameter, with the following scores:

Table 3-22: Underground Cables - Age Related Score

Condition Rating	Age
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	Older than 40 years

(b) Historic Rates of Circuit Failures

Historic failure rates on a cable circuit are an excellent indicator of the cable health and condition and its useful remaining life and therefore employed in cable Health Index formulation as indicated below:

Table 3-23: Underground Cables – Failure Related Score

Condition Rating	Component Condition
A	Less than 0.5 Failures per 10 km in the last 5 years
B	0.5 to 1.0 Failures per 10 km in the last 5 years
C	1.0 to 1.5 Failures per 10 km in the last 5 years
D	1.5 to 2.5 Failures per 10 km in the last 5 years
E	2.5 or more Failures per 10 km in the last 5 years

(c) Condition of Cable Splices or Stress Cones

Physical condition of cable splices or stress cones can be employed in assessing overall condition of the cable circuit:

Table 3-24: Underground Cables - Splice or Stress Cone Related Health Score

Condition Rating	Component Condition
A	Splice or Stress Cone appears in good condition, no indication of moisture ingress
C	Normal wear, no apparent damage, no evidence of moisture ingress
E	Poor condition, potential moisture ingress or IR indicates hot spot

3.3.3. Condition Assessment Criteria for Manholes and Vaults

Manholes provide the junction point on underground ducts to facilitate cable pulling and provide access for inspection of cable splices. Vaults provide below grade space of installation of electrical equipment such as submersible transformers or switches. In the case of both manholes and vaults, steel reinforced concrete is used for walls, roofs and floors. In locations subject to flooding floor drains and sump pumps are provided. Vaults where heat generating equipment such as distribution transformers are installed are also equipped with ventilation grates. Man access is provided through the top. When vaults and manholes are located in road ways, parking lots or other areas open to vehicular traffic, the structures must be designed by a structural engineer. Since manholes and vaults are confined spaces, they must be adequately sized to rescue trapped workers during a fire or explosion inside the vault or manhole.

The common degradation mode for manholes and vaults is the deterioration of concrete structures due to concrete spalling and corrosion of rebar, sinking of the roof top surfaces allowing rain water to collect and flood the manhole and vaults. Functional obsolescence, where the size of the manhole or vault no longer meets the space requirements can also lead to end of life of a structure.

3.3.4. Ranking Condition of Manholes and Vaults through Multiple Criteria

The health and condition of manhole and vaults can be measured through visual inspections, looking for:

- Structural damage to concrete walls or roof
- Frequent flooding incidents of the vaults or manholes
- Non-functioning drains or sump pumps
- Inadequate space

(a) Structural Condition

Table 3-25: Manhole and Vaults – Structural Health Score

Condition Rating	Inspections
A	No deficiencies in the vault or manhole
C	Only minor deficiencies
E	Major deficiencies requiring immediate repairs/replacement

(b) Flooding Incidents, Drains, Sump Pumps

Table 3-26: Manhole and Vaults - Flooding Related Health Score

Condition Rating	Inspections
A	No incidents of Flooding at this location
C	Occasional Flooding, working sump pumps and drains
E	Frequent Flooding, No sump pumps or drains

(c) Vault Size and Access:

Table 3-27: Manholes and Vaults – Size Related Health Score

Condition Rating	Inspections
A	Adequate ergonomic size and safe access to vault
C	Vault size slightly smaller than ideal, but adequate for safe working and reasonable access to vault
E	Vault size or access inadequate for safe working or worker rescue during an accident immediate repairs/replacement

3.3.5. Health Index Formulation for Underground Cables, Manholes and Vaults

Health indexing quantifies equipment conditions relative to long-term degradation factors that cumulatively lead to an asset's end-of-life. Health indexing differs from maintenance testing, which emphasizes finding defects and deficiencies that need correction or remediation to keep the asset operating during some time period.

For purposes of formulating the Health Index for underground cables and manholes/vaults, it is proposed to assign the following weights to various health index criteria:

Table 3-28: Cables, Splices and Terminators Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age of Cable Circuit	A – E	5	3	15
4	Historic Failure rates	A – E	5	8	40
5	Visual inspection of splices or stress cones	A – E	5	1	5
	Total				60

Table 3-29: Manholes and Vaults Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Structural Integrity	A – E	5	8	40
2	Flooding and Its mitigation	A – E	5	4	20
3	Size and Access	A – E	5	8	40
	Total				100

3.4. Distribution Transformers

3.4.1. Different Types of Distribution Transformers

Four (4) main types of distribution transformers are commonly employed on distribution system:

- Pole mounted transformers
- 1-Phase Pad mounted transformers
- 3-Phase Pad mounted transformers
- Submersible transformers in vaults

Aside from the different design and construction standards employed in their manufacture and installation, each type of transformer serves the same functions and the same asset management strategy can be employed for these assets as described below:

Distribution transformers step down to the medium voltage distribution power to final utilization voltage of either 120/240V, 120/208V or 347/600 V. Both single phase and three phase transformers are in use. In pole top applications, three single phase transformers are commonly employed to create a three phase bank, however for pad mounted applications, three phase transformers are used for three phase applications.

The key components of a distribution transformer are:

- primary and secondary coils, made of copper or aluminium conductors
- magnetic core made of iron laminations
- insulation system, commonly consisting of paper and mineral oil
- sealed transformer tank
- primary and secondary bushings or bushing wells to accommodate elbows
- auxiliary devices

The most critical component in transformer aging consideration is the insulation system, consisting of mineral oil and paper. Transformer oil consists of hydrocarbon compounds that degrade with time due to oxidation, resulting in formation of moisture, organic acids and sludge. The oil oxidation rate is a function of operating temperature. Increased acidity and moisture content in insulating oil causes accelerated degradation of insulation paper. Formation of sludge adversely impacts the cooling efficiency of transformer, resulting in higher operating temperatures and further increasing the rate of oxidation of both the oil and the paper. Distribution transformers commonly fail when the age weakened insulation system is subjected to a voltage surge during lightning.

Most utilities run the distribution transformers to failure, i.e. replace them only after they fail. With the exception of rust proofing and painting of the tanks, replacing a damaged bushing or repairing a leaky gasket, very little invasive preventative maintenance or testing is carried out on distribution transformers.

3.4.2. Ranking the Condition of Distribution Transformers through Multiple Criteria

Just as in case of substation transformers multiple criteria, including service age, loading levels, results of oil testing and physical inspections can be employed for assessing the condition of distribution transformers. However, since the consequences of in-service failure of distribution transformers are relatively minor, most distribution utilities, including PUC DISTRIBUTION employ run-to-failure strategy for distribution transformers, thus avoiding costs related to oil testing or measuring load levels.

Since the service age provides a reasonably good measure of the remaining life of transformers, it is employed as an assessment parameter, with the following scores:

(a) Condition Assessment Based on Age

Table 3-30: Distribution Transformer Age Based Scoring

Condition Rating	Distribution Transformer Age
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	Older than 40 years

(b) Visual Inspections

Visual inspections can provide a good indication of the physical condition of transformers, which can be ranked as indicated below:

Table 3-31: Distribution Transformers – Inspections Based Health Scoring

Condition Rating	Visual Inspections
A	No rust on tank/enclosure, no damage to bushings, no sign of oil leaks, padlocks in good condition on pad mounted transformers
B	Only one of the following defects: Minor rust, or minor cracks in bushings or minor oil leak
C	Two or more of the above indicated defects present but do not impact safe operation
D	Tank/radiator badly rusted or major damage to bushing or major oil leak
E	Two or more of the above indicated defects

3.4.3. Health Index Formulation for Distribution Transformers

Table 3-32: Distribution Transformers Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age of transformer	A – E	5	10	50
3	Visual inspection	A – E	5	10	50
	Total				100

3.5. Disconnect Switches and Cut-outs

3.5.1. Different Types of Switching Devices

This asset class includes pad and vault mounted medium voltage switchgear, K-bars, as well as pole mounted ganged disconnect switches and single phase solid blade or cutouts. Disconnect switches and K-bars provide means of load disconnect and isolation for equipment, such as underground laterals or distribution transformers.

The key components of a distribution switch are:

- Switch blades
- Operating handle and mechanism
- Insulator bushings
- Grounding and bonding conductors

Pad mounted disconnects have the following additional components:

- Pad or vault mounted metal enclosure
- Inter-phase glass polyester barriers
- Padlocks

K-bars have the following main components

- Insulator bushings and buses
- Grounding and bonding conductors
- Pad mounted metal enclosure

The most critical components in the disconnect switch are the switch blades and operating mechanism. Misaligned or poorly surfaced contacts can result in excessive arcing during switch opening or closing, resulting in further deterioration of the blades. Corrosion may cause rusting of the links and pins in the operating mechanism reducing the blade movement speed. Broken grounds or damaged insulators are some other defects that may appear with age.

Pad or vault mounted disconnect switch enclosures are vulnerable to corrosion due to road salt spray. Non-functioning padlocks or broken inter-phase barriers are other serious defects that may develop with aging.

In case of K-bars, corrosion of steel enclosures and degradation of bushings with service age are the key degradation modes.

3.5.2. Ranking Condition of Disconnect Switches through Multiple Criteria

(a) Age Related Scoring

Since the service age provides a reasonably good measure of the remaining life of disconnect switches and K-bars, it is employed as an assessment parameter, with the following scores:

Table 3-33: K-bar, Disconnect Switches and Cutouts – Age Based Health Scoring

Condition Rating	Disconnect Switch Age
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	Older than 40 years

(b) Visual Inspections

Visual inspections can provide a good indication of the physical condition of disconnect switches or K-bars. Infrared (IR) scan can provide indication of hot spots resulting from misaligned blades.

Table 3-34: K-bar or Disconnect Switches or Cutouts – Inspections Based Scoring

Condition Rating	Visual Inspections
A	No rust on tank/enclosure, no damage to bushings, padlocks in good condition on pad mounted switchgear, operating mechanism and blades in excellent condition
B	Only minor wear, no defects
C	No more than one of the above indicated defects present but does not impact safe operation
D	Two or more of above indicated defects, but they can be repaired
E	Two or more of the above indicated defects, but they cannot be repaired

3.5.3. Health Index Formulation for Disconnect Switches

Table 3-35: Distribution Switches and Cutouts – Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age of disconnect	A – E	5	10	50
2	Visual inspections and IR Scan	A – E	5	10	50
	Total				100

4 ASSET DEMOGRAPHICS AND CONDITION ASSESSMENT

The methodology described in detail in section 3 provides means of accurate and comprehensive condition assessment of all major assets employed on the distribution system. This section of the report, documents the health indices for fixed assets employed on the distribution system, determined by taking into account all available information about assets from testing, inspections, service age and other demographic information, retrieved from the GIS system. Where complete information required for condition assessment of an asset class through methodologies described in Section 3 was not available, the health index algorithm was appropriately modified to make use of the available information, to determine health indices of assets.

4.1. *Transformer Stations and Distribution Substations*

Figure 4.1 shows the location of transformer stations and distribution stations owned and operated by PUC DISTRIBUTION. There are two transformer stations TS1 and TS2, which step down power received from the transmitter at 115 kV to 34.5 kV, and 12 distribution stations, which step down power from 34.5 kV to 12.47 kV. There are also three additional distribution stations; one which steps down from 34.5kV to 4.16kV, one which step down from 12.47 kV to 4.16 kV, and one which steps down from 34.5kV to both 12.47kV and 4.16kV. The three 4.16 kV distribution stations (Sub 4, Sub 5 and Sub 14) will be retired from service, upon completion of the distribution voltage upgrade program and replaced with a single 34.5/12.47 kV station.

Figure 4-1: Distribution Station Locations

The results of condition assessment of major equipment employed at step-down stations are described below in detail.

4.1.1. Station Transformers

Figure 4-2 presents the age profile of power transformers employed at PUC DISTRIBUTION's step-down stations. As shown, approximately two thirds of the power transformers have reached a service age of greater than 35 years and four of the power transformers have been in service for more than 50 years. The transformer numbers in Figure 2 are not stacked in any priority order.

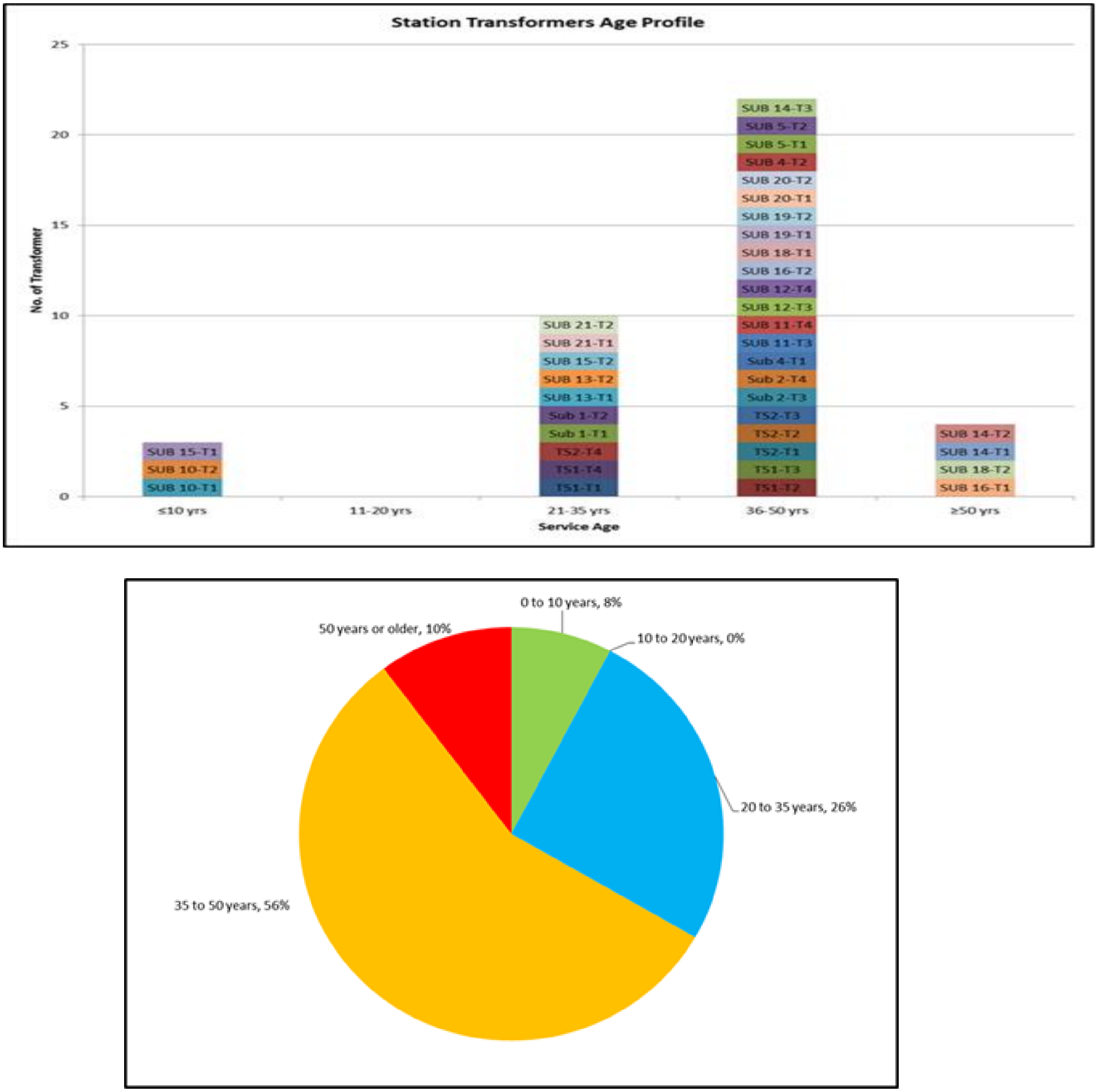


Figure 4-2: Age Profile of Station Transformers

Based on the condition assessment criteria detailed in Section 3, Health Index score has been calculated for each of the substation transformers and the results are summarized in Figure 4-3. It is noteworthy that the following transformers have undergone rehabilitation of the coil, which has been taken into account during calculation of the health index for these transformers:

- Sub 16-T1 (2013)
- Sub 13-T1 (2010)
- Sub 18-T1 (2008)
- Sub 19-T1 (2003)
- TS2 - T4 (1998)
- Sub 11-T4 (1992)

As shown, a total of 20 power transformers have determined to be in "poor" or "very poor" condition, 16 power transformers have been determined to be in fair condition and 3 transformers have been determined to be in in good or very good condition.

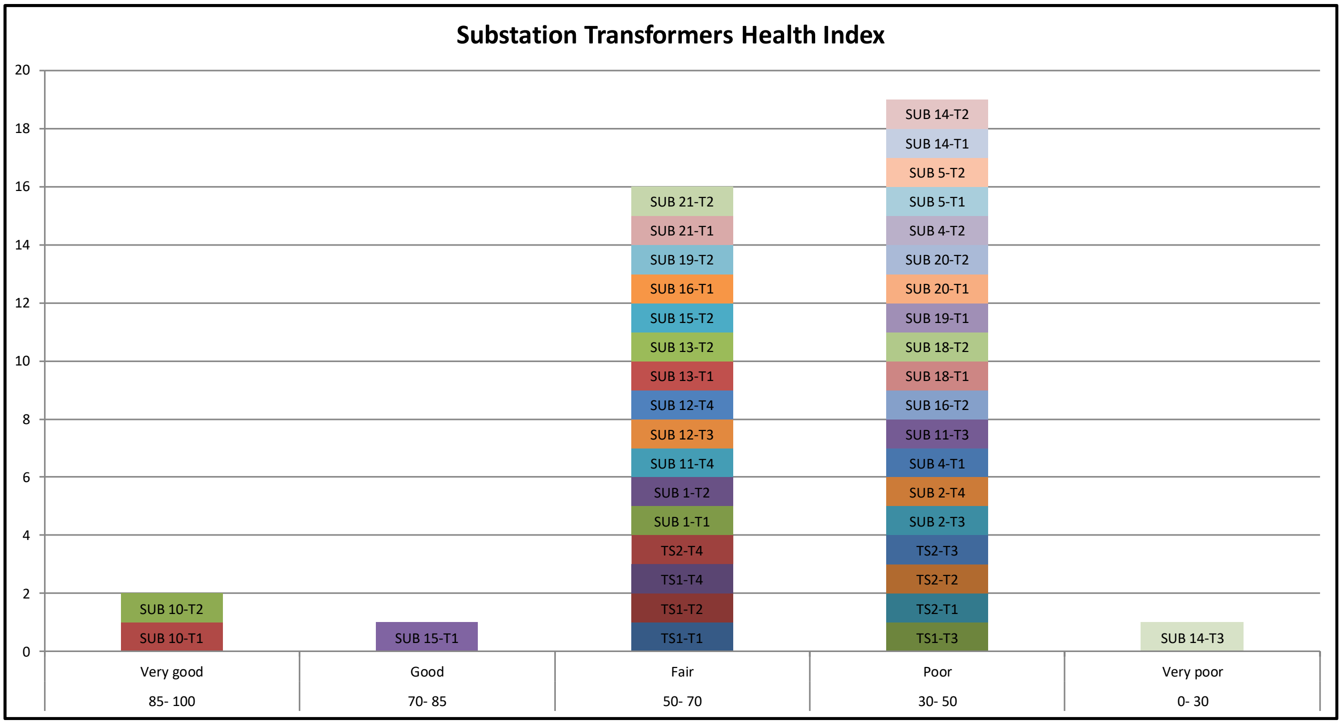


Figure 4-3: Health Index of Power Transformers Employed at Stations

4.1.2. Station Switchgear - Circuit Breakers

By taking into account the service age, the results of visual inspections and maintenance test reports (where available), Health Index score has been calculated for switchgear employed at the stations and the results are summarized in Figure 4-3. As indicated, switchgear at 14 of the stations has been determined to be in poor or very poor condition.

Although protection relays at most of the stations have been upgraded to modern solid state relays in the past, many stations employ switchgear designed and constructed using technologies, which are now considered obsolete. For example, both of the 115/34.5 kV stations employ oil circuit breakers for switching and protection on 115 kV bus. This type of circuit breaker design does not only require extensive preventative maintenance, but since the manufacture of circuit breakers using this technology has been abandoned for over 30 years, the spare parts are difficult to obtain and are costly. Similarly, a majority of the 34.5/12.47 kV stations employ magnetic air circuit breakers, which also require more frequent preventative maintenance in relation to modern technologies, employing vacuum circuit breakers and it is difficult and costly to obtain spare parts for the old vintage switchgear. Also the arc flash regulations under CSA Standard Z462 have undergone change over the years. The switchgear of older designs require complicated work methods to perform maintenance.

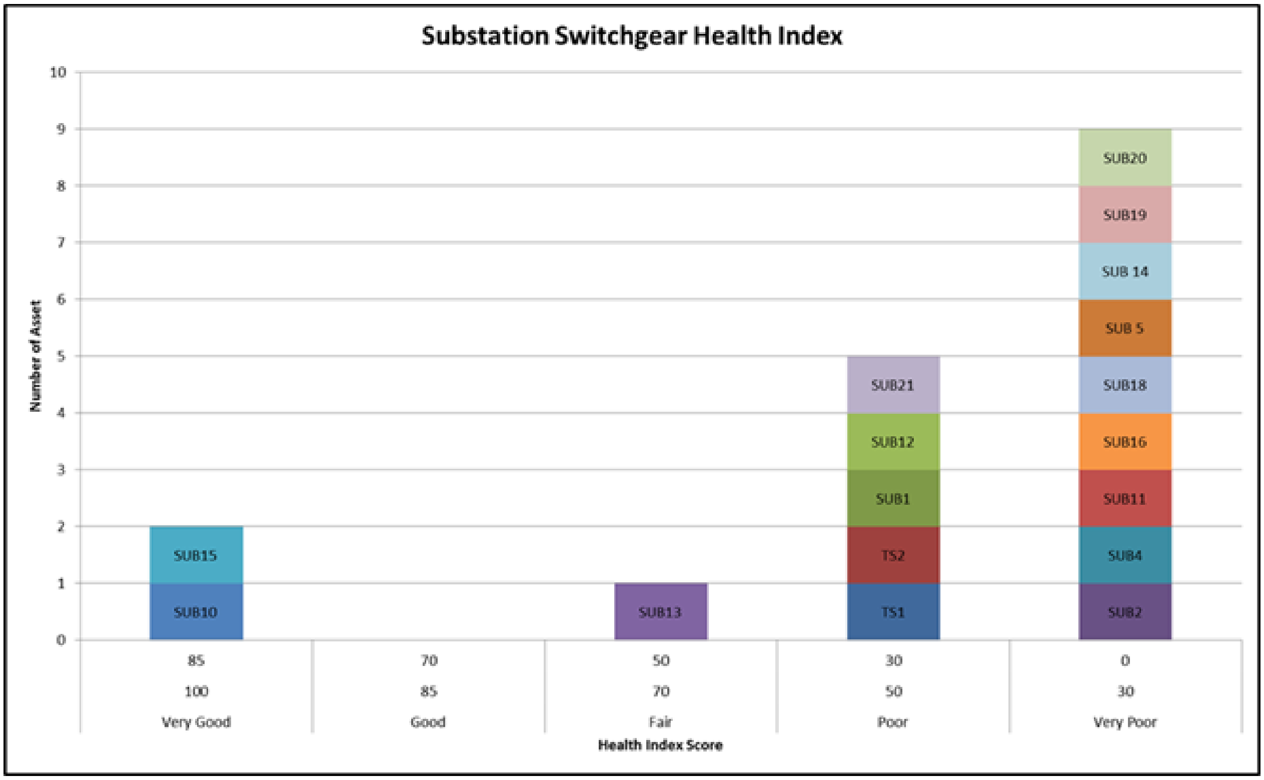


Figure 4-4: Condition Assessment of Station Switchgear

4.1.3. Stations Supervisory Control (SCADA) and Communication System

PUC DISTRIBUTION's SCADA network is comprised of 42 nodes in the form of remote terminal units (RTU's). The main SCADA server and operator's station is located at PUC's head office and a backup server and operator's station located at PUC's affiliate company's Water Treatment Plant. The interconnection between the servers, stations, and distributed devices is based on a fibre network with radio system tie-ins for sites where fibre is not cost effective. 9 of the 17 distribution and transmission stations are connected via fibre with the remaining 8 being on a MDS radio network. There are three distributed voltage regulators and three reclosures that are also on the MDS radio network. PUC also has 15 motor operated switches connected to SCADA via a Speednet radio system, which includes 3 repeaters.

Most of the network infrastructure has been upgraded since 2009 and it has expected design life of 15 years. The MDS master radio, which provides the interconnection between the remote MDS radios and fibre core, is planned to be replaced in 2016.

Each of the distribution stations is equipped with DC battery backup of adequate rating to run the station network infrastructure and RTU's for a minimum of 8 hours in the case of an AC power outage. Control battery typically provides a service life of approximately 15 years. PUC has taken the approach of replacing 1 distribution station battery bank and charger on an annual basis. The DC system chargers have a lifespan of 25 to 30 years. PUC requires redundant DC systems at each of the 2 transmission stations and has taken the approach of replacing 1 of the 4 total TS DC systems every 3 years. The cost of 115/34.5 kV station DC systems is substantially greater than 34.5/12.47 kV station DC systems due to the size required to run an entire transmission station.

4.1.4. Other Assets Employed at Stations:

Other important assets employed in stations include buildings, fences, ground grids and surface stone in station yards. Although a majority of the stations are old, the buildings are well maintained and in satisfactory condition.

The station ground grids have not been tested over the recent years to provide an accurate assessment of their condition. The condition assessment of ground grid, building and fences is based on visual inspections only.

By taking into account the service age and results of visual inspections, composite Health Index score for the buildings, yards, fences and ground grids was calculated and the condition of these assets is indicated is Figure 4.5. Two additional substations MS-5 and MS-14 are also in poor condition, but these are not included in Figure 4.5, as both of these stations are planned to be retired upon completion of the voltage conversion project and therefore these are not considered candidates for asset renewal.

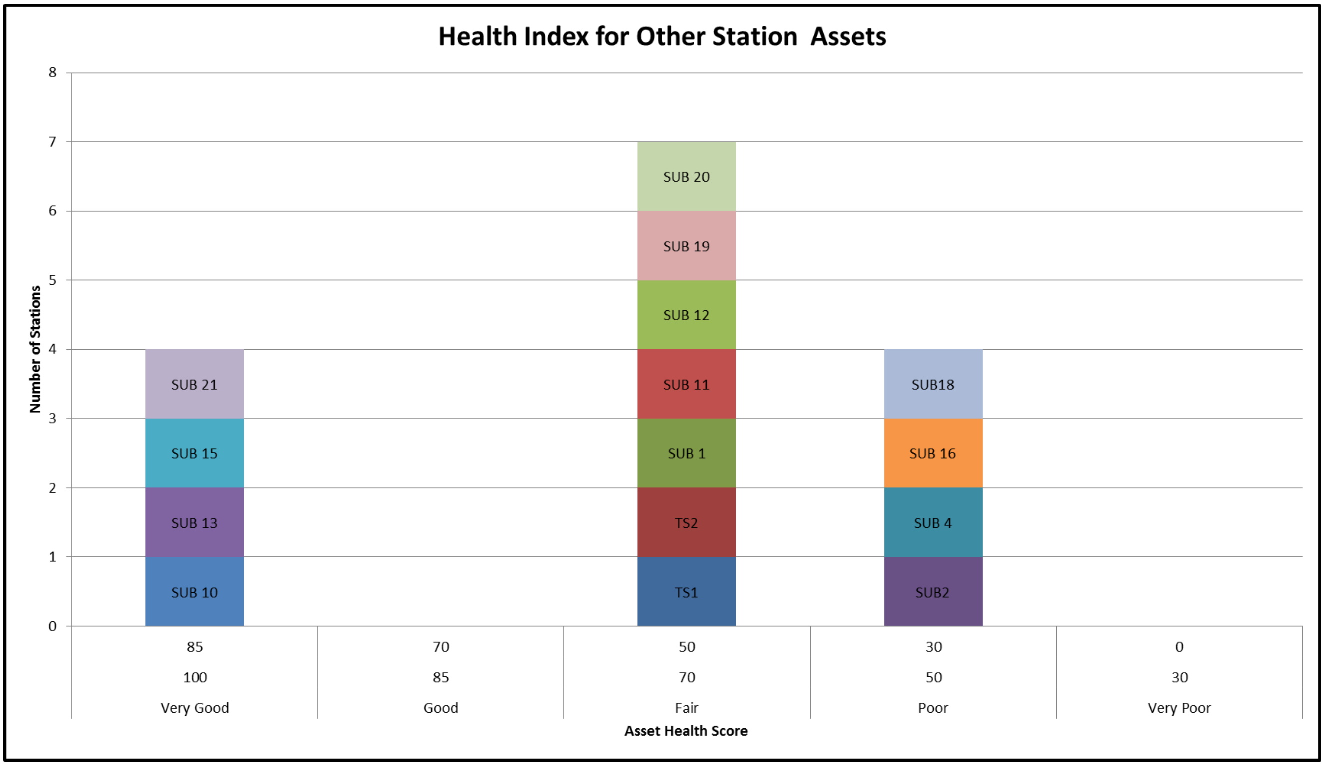


Figure 4-5: Condition Assessment of Auxiliary Assets

4.2. *Overhead Lines*

4.2.1. Distribution Line Support Poles

Based on the demographic information retrieved from the GIS system, there are approximately 12,600 wood poles and about 80 other types of poles (including steel, concrete and fiberglass) employed on PUC DISTRIBUTION's electricity distribution system. Figure 4-6 displays the age profile of line support poles employed on the distribution system. Approximately 328 poles (shown in red) have been in service for more than 60 years and an additional 857 poles (shown in yellow) have been in service for more than 50 and less than 60 years. More than 28% of the poles currently in service have a service age of 40 years more.

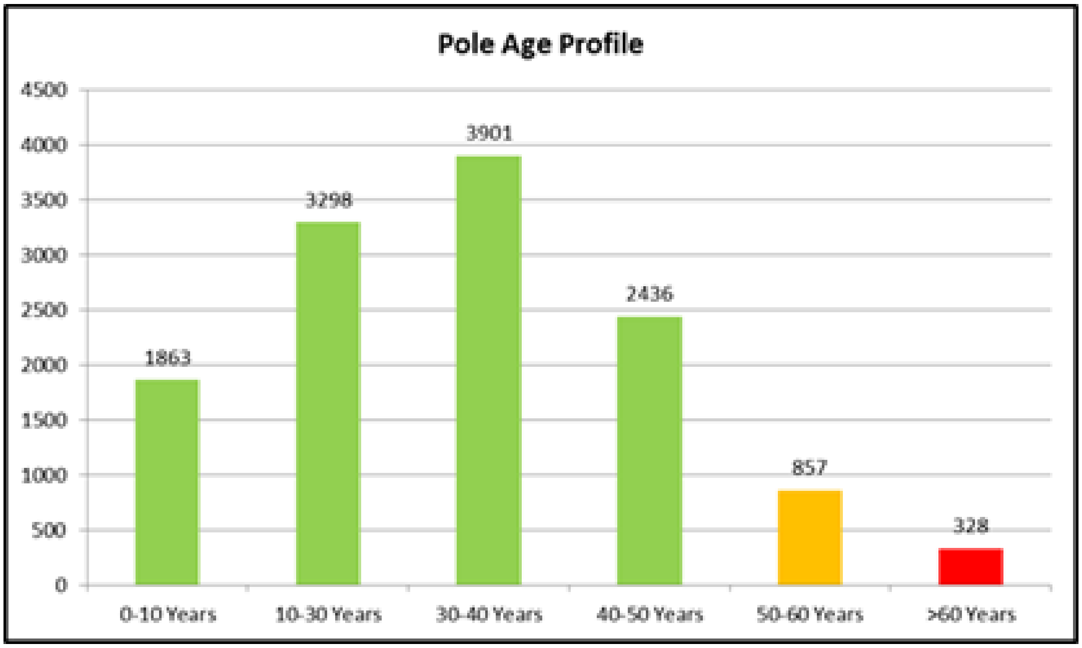


Figure 4-6: Age Demographics of Distribution Line Poles

Poles on distribution lines are employed in different configurations; some support only low voltage circuits, while others may support multiple circuits of different voltages, requiring taller poles. Figure 4-7 indicates the approximate percentage of different pole heights employed on the distribution system. As indicated, 35ft, 40ft and 45ft poles are used most commonly.

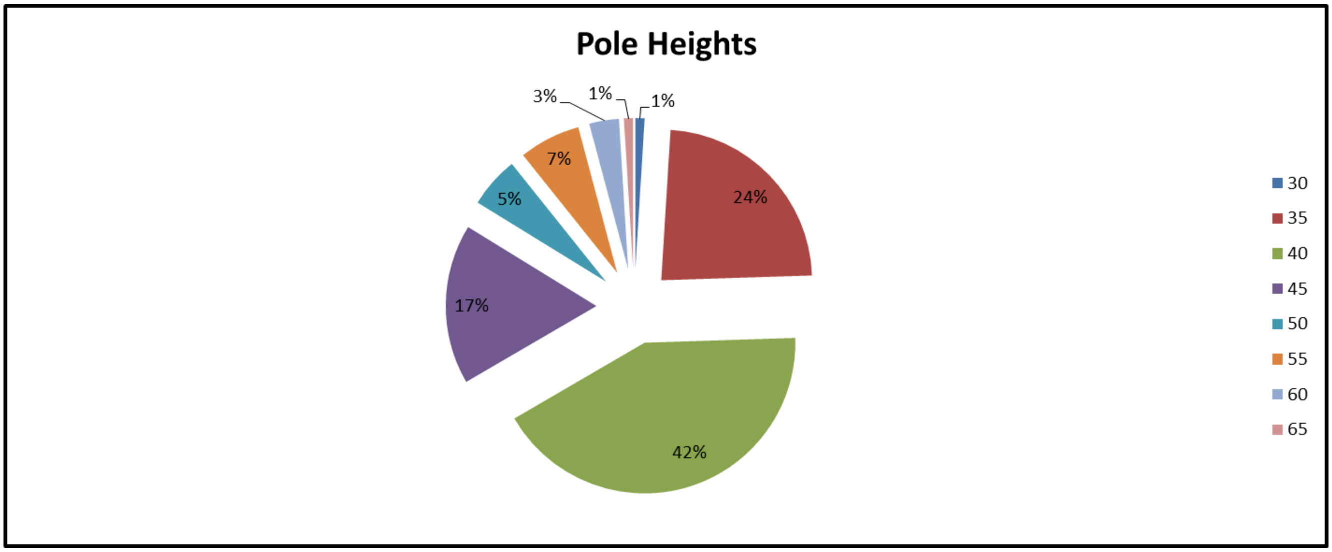


Figure 4-7: Distribution Pole Heights

Figure 4-8 displays the age profile of the poles with respect to their heights and as indicated a majority of the poles that have reached more than 50 years of service age fall within the 35', 40' and 45' height ranges.

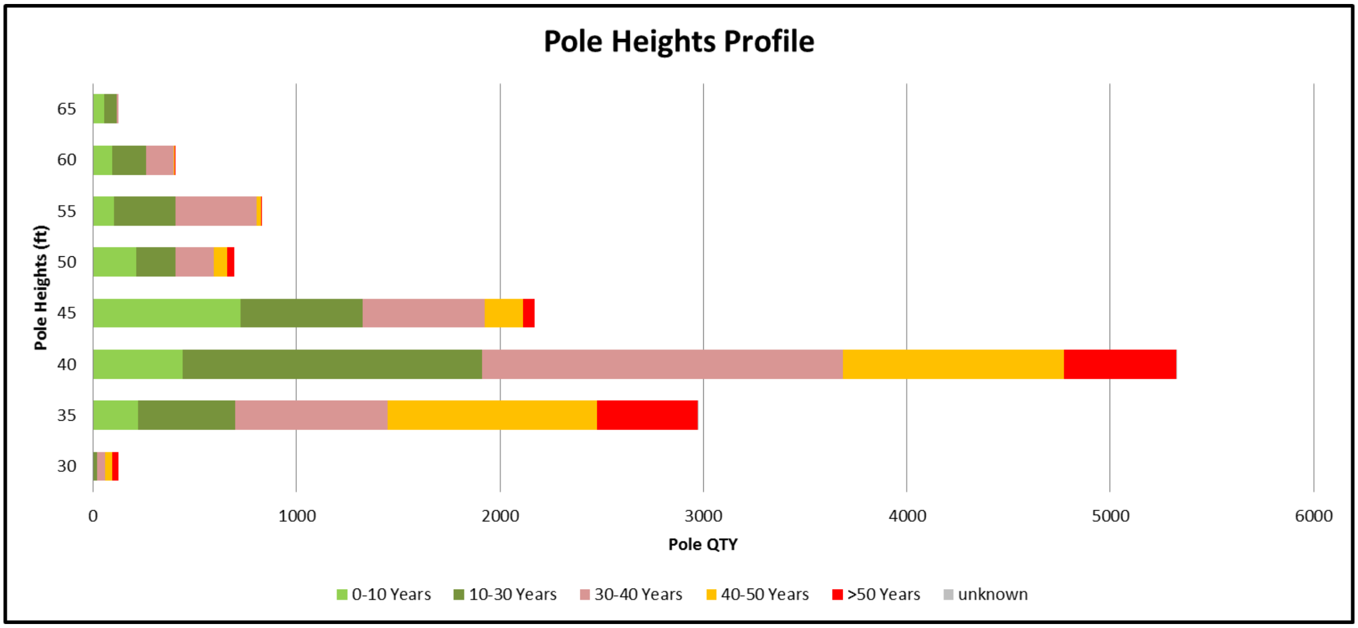


Figure 4-8: Age Profile of Poles of different Heights

PUC DISTRIBUTION has an on-going non-destructive pole testing program since 2003. Figure 4.9 shows the percentage of poles found in various conditions of strength through pole testing from 2003 to 2013. In this case, the Health Index score is calculated based on the remaining strength of the pole, where "very poor" equates to less than 3 years of remaining useful life, "poor" equates to less than 5 years of anticipated remaining useful life and "fair equates to anticipated remaining useful life of "5 to 20" years.

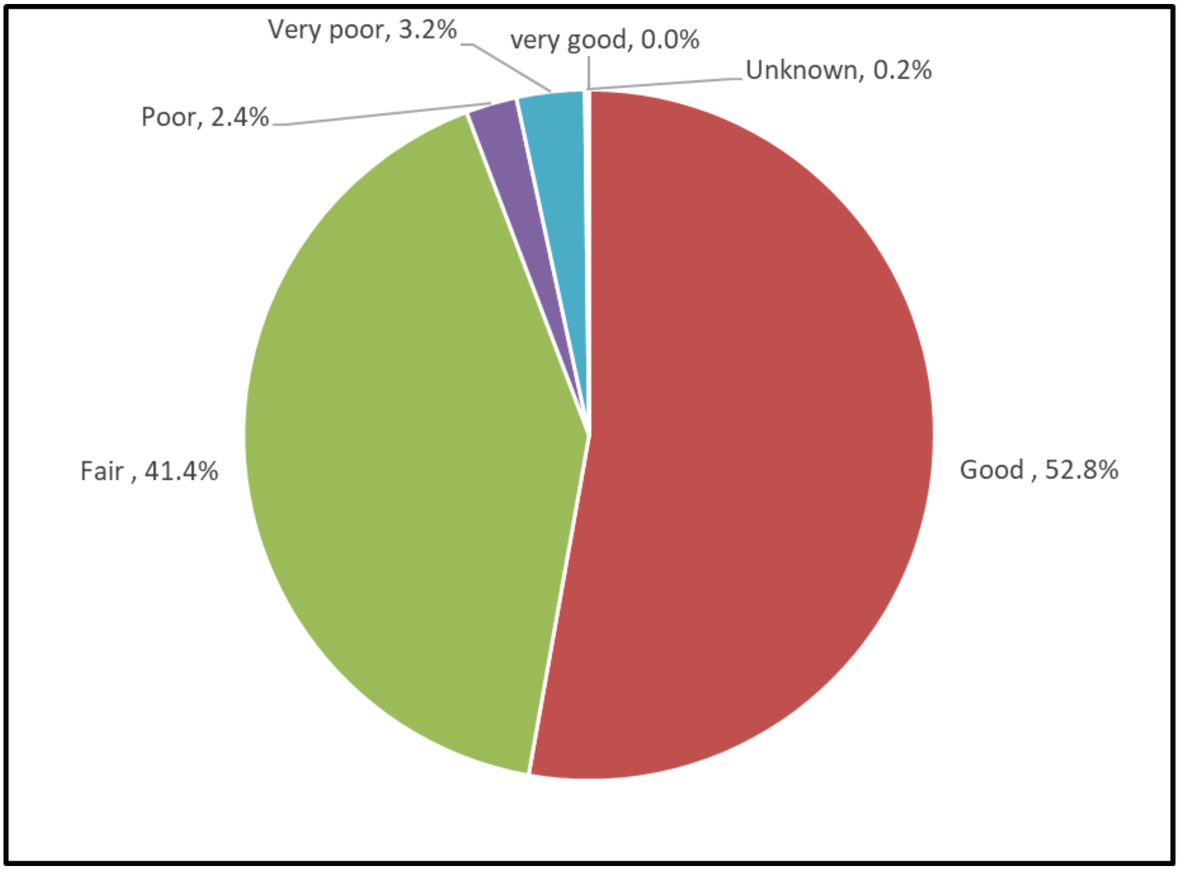


Figure 4-9: Condition Assessment of Wood Poles 2003 to 2013 Test Results

After the pole testing is completed poles found in very poor and poor condition are replaced during the following years. Pole testing has not been done during 2014 and 2015, but the tests during the previous ten years were performed on the entire population of poles. The results of this analysis are presented in Figure 4-10., indicating that approximately 700 poles were found to have reached "poor" or "very poor" condition over a period of ten years, requiring replacement of approximately 70 poles each year. Since a portion of the poles found in poor condition are employed on 4 kV lines, approximately half of the poles found in poor condition are simply retired from service during implementation of voltage upgrade program.

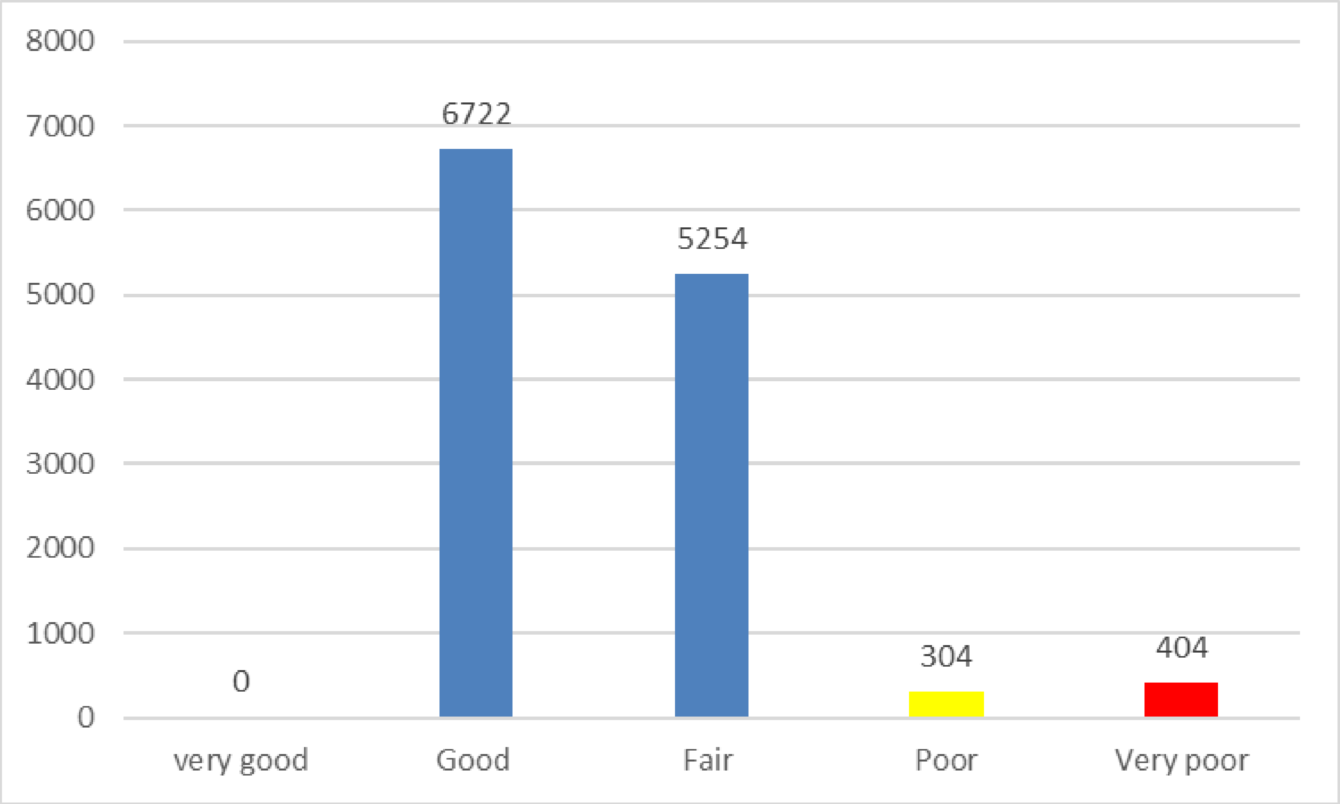


Figure 4-10: Wood Poles Health Index Score for Entire Pole Population

4.2.2. Overhead Line Conductors

PUC DISTRIBUTION's overhead distribution network employs approximately 391 km. of 3-phase and approximately 230 km of 1-ph lines, all operating at 115kV, 34.5 kV, 12.5kV, 7.2kV, 4.2kV and, 2.4 kV. Figure 4-11 and Figure 4-12, respectively, show the age profile of overhead lines and as shown, approximately 29% of the 3-ph lines and approximately 29% of the 1-ph lines will reach the end of their design service life of 45 years during the next five years. As the lines approach the end of their design life, all line components including wood poles, mounting hardware and conductors experience degradation of strength and pose a high risk of failure in service when subjected to design loading during wind and ice storms. To mitigate this risk, these lines will require rebuild with new poles and conductors.

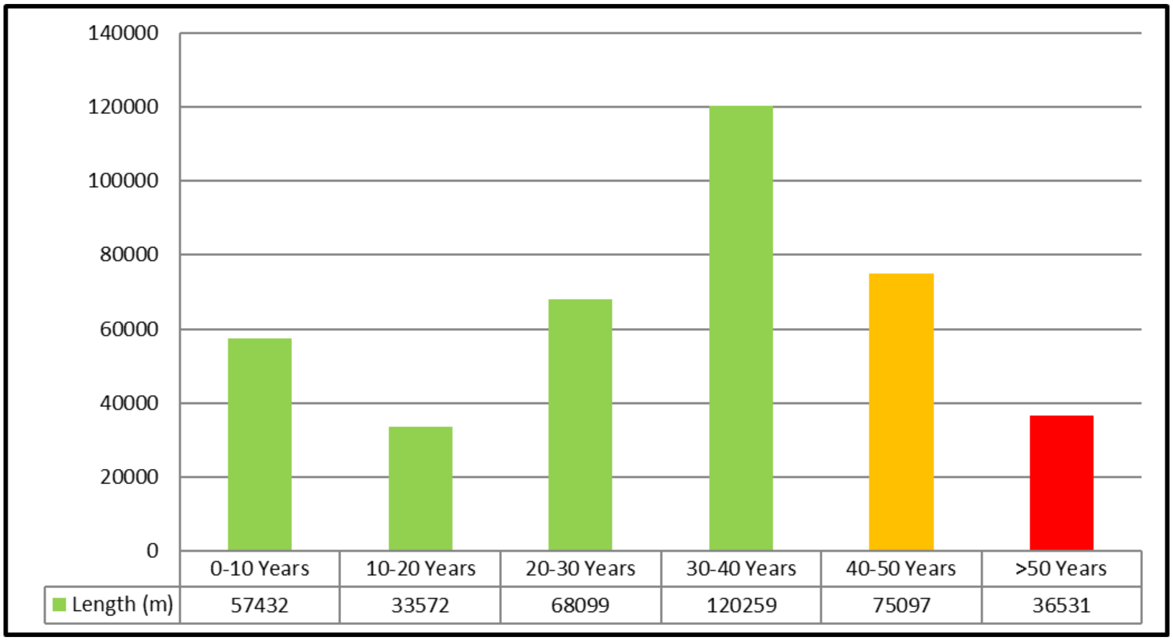


Figure 4-11: Age Profile – 3 Phase Overhead Lines

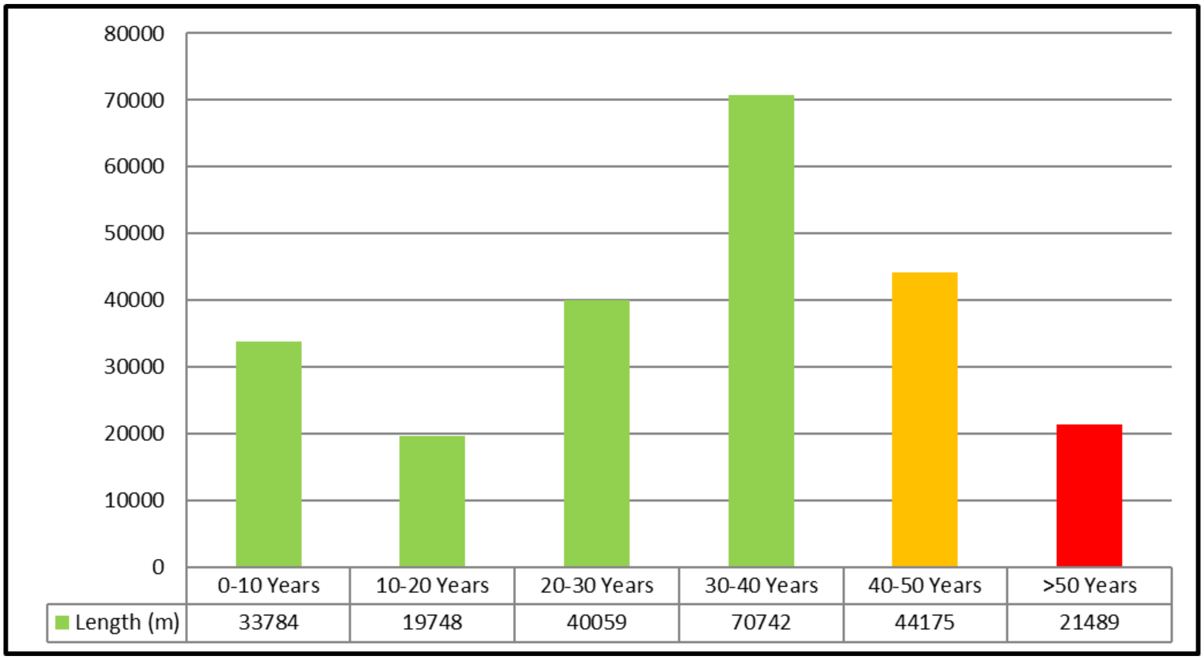


Figure 4-12: Age Profile – 1 Phase Overhead Lines

While the service age of ACSR or aluminum conductors is not generally on the critical path to determine the end of service life of overhead distribution lines, a small fraction of the PUC DISTRIBUTION's overhead lines employ copper conductors of small cross-section (#6 or smaller). These conductors are commonly referred to as "restricted conductors" and they are known to degrade in mechanical strength with service age, due to reduction in their tensile strength.

Recognizing the high risk of failure in service of restricted conductors, PUC DISTRIBUTION adopted a program for replacing the restricted conductors in 2009. Figure 4-13 and Figure 4-14 show the progress made to date in replacing the restricted conductors and the extent of lines with restricted conductors still in service as of the end of 2015. All existing overhead lines with restricted conductors are determined to be in poor condition and it is recommended the work of reconstructing these lines with aluminum conductor should continue.

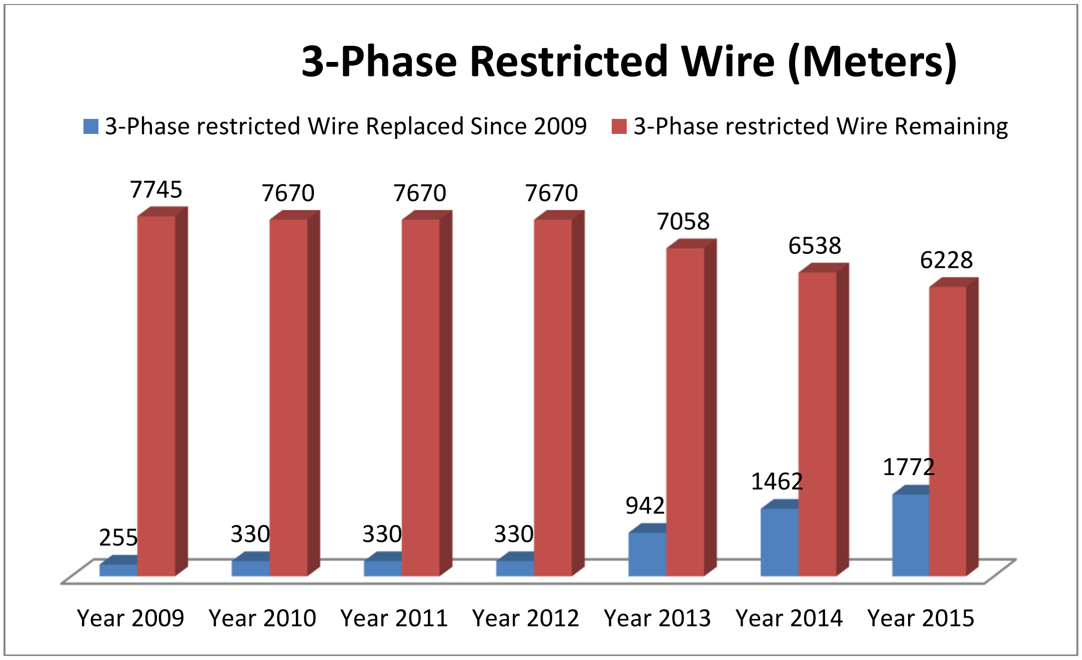


Figure 4-13: 3-Phase Overhead Line Lengths with Restricted Conductors

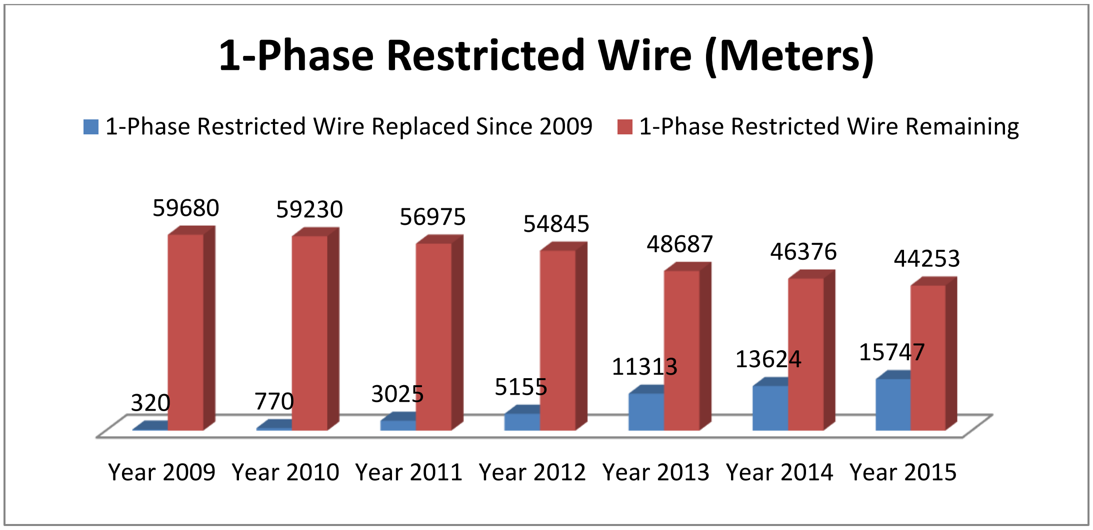


Figure 4-14: 1-Phase Overhead Line Lengths with Restricted Conductors

4.2.3. Overhead Distribution Switches and Cut-outs

PUC DISTRIBUTION's overhead lines are well equipped for disconnecting and isolating, load-breaking, and fault interrupting to provide means of isolation during power interruptions and operational functions and adequately protect the circuits during system faults. A majority of the line switches are pole type. Hook-switch operated cutouts are used for switching and isolating pole mounted transformers. The age data for the overhead switches and cutouts was unavailable, but the line switches and cutouts are typically replaced at the time of reconstruction of the line.

Porcelain insulated cut-outs have been in use in the electrical industry for many decades. Porcelain was also the material of choice for most other electrical equipment that required insulation, i.e. line insulators, arresters and bushings. In the early 1980's large numbers of porcelain insulators began failing, particularly in cold climate regions. "Cement growth" was causing insulators to crack. The expansion and contraction of the adhesive interface which joined the porcelain to the hardware (connector) caused stresses on the porcelain. These stresses caused small cracks to appear in the porcelain which eventually lead to an electrical and/or mechanical failure of the porcelain insulator.

Distribution insulators had been the focus of the industry's attention throughout the past 30 years, resulting in expenditure of millions of dollars to rectify the problem of defective porcelain. During the past several years many utilities throughout North America have seen increasing failures of their porcelain insulated cut-outs. The mode of failure is very similar to that of insulators. Small cracks in the porcelain initially appear near the interface between the porcelain and hardware. These fractures eventually lead to a mechanical failure of the cut-out. Cement growth is the likely cause of the initial cracks. The breakage of porcelain insulated cut-outs is a concern from a safety and reliability perspective. During cut-out operation the porcelain can break causing the cut-out to separate into two parts. This creates a hazard to line personnel operating the cut-out and can cause outages to customers. The common industry solution to this problem has been replacement of the porcelain insulated cut-outs with polymer insulated cut-outs, as shown in Figure 4-15.

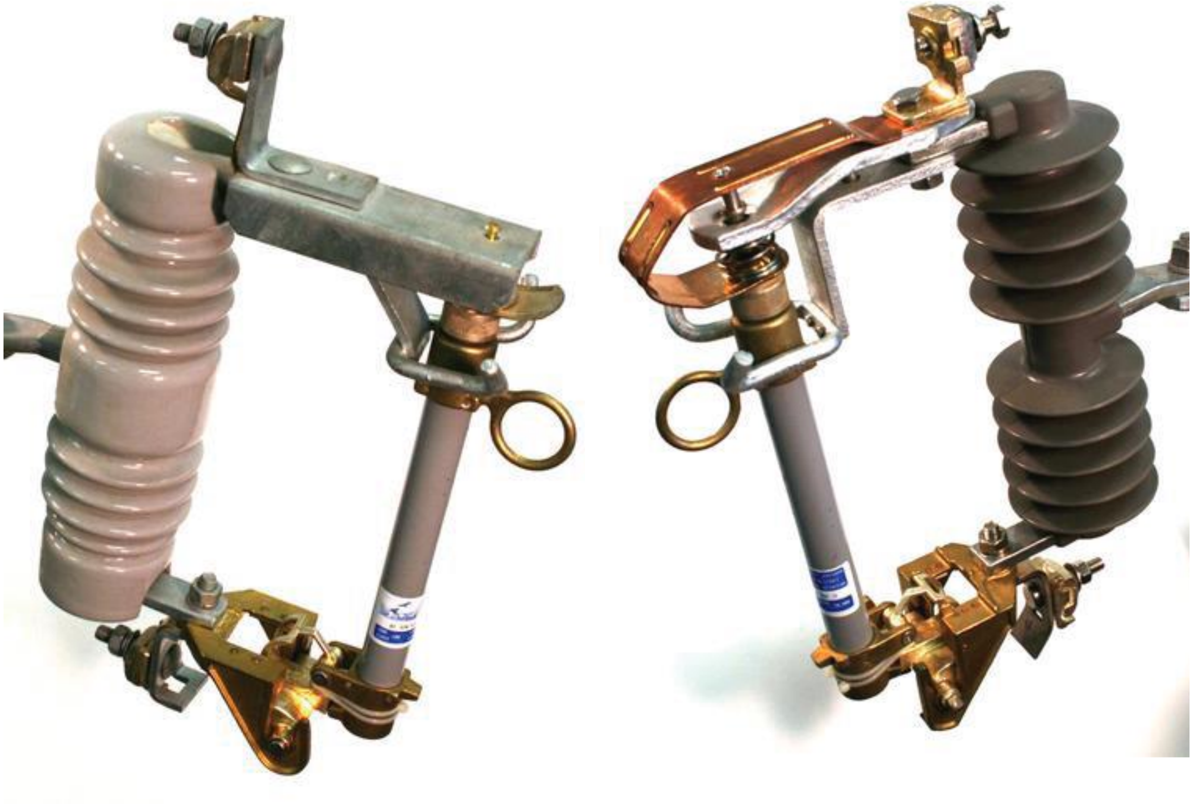


Figure 4-15: Porcelain (Left) and Polymer (Right) Insulated Cut-outs

PUC DISTRIBUTION has also been systematically replacing the porcelain cut-outs and switches with polymer cut-outs switches since 2010. Approximately 2700 defective switches and cut-outs were identified for replacement under this program and by the end of 2015 replacement of all but about 100 of the defective switches and cut-outs had been completed. The remaining 100 defective switches and cut-outs are scheduled for replacement in 2016 and this program will be complete by the end of 2016.

4.3. *Underground Distribution System*

4.3.1. Underground Primary Conductors

The underground distribution network at PUC DISTRIBUTION employs approximately 75 km. of 3-phase cable circuits and approximately 47 km of 1-phase and 2-phase cable circuits. Figure 4-16 and Figure 4-17, respectively, show the age profile of distribution cable on 3-phase and on 1-phase and two phase 12.5 kV distribution circuits as of 2015. Approximately 25% of the cable has reached service age of greater than 40 years. There are no practical tests available which could be economically performed in field to accurately assess the remaining useful life of cables. However, XLPE insulated cables, which are typically employed on underground distribution systems, generally begin to experience an increase in failure rates when they get past 40 years of service age. It is also noteworthy that a vast majority of the cables installed prior to 1990 were installed in direct buried configuration. Cable failures in direct buried configurations have significantly larger impact on reliability than failures that occur where cables are installed in duct. All cable circuits past 40 years of service age are considered in poor condition.

Figure 4-18 and Figure 4-19, respectively, show the age profile of distribution cables employed on 3-phase and 1-phase circuits at 4.16 kV. As indicated, a majority of these cables are past their 40 year typical useful service life. These cables are generally planned to be removed from service when these service areas are upgraded to 12.47 kV. The relatively small amount of cable, with service age of less than 20 years age, is rated for use on 12.5 kV (in anticipation of the voltage conversion) and these circuits will remain in service after voltage conversion.

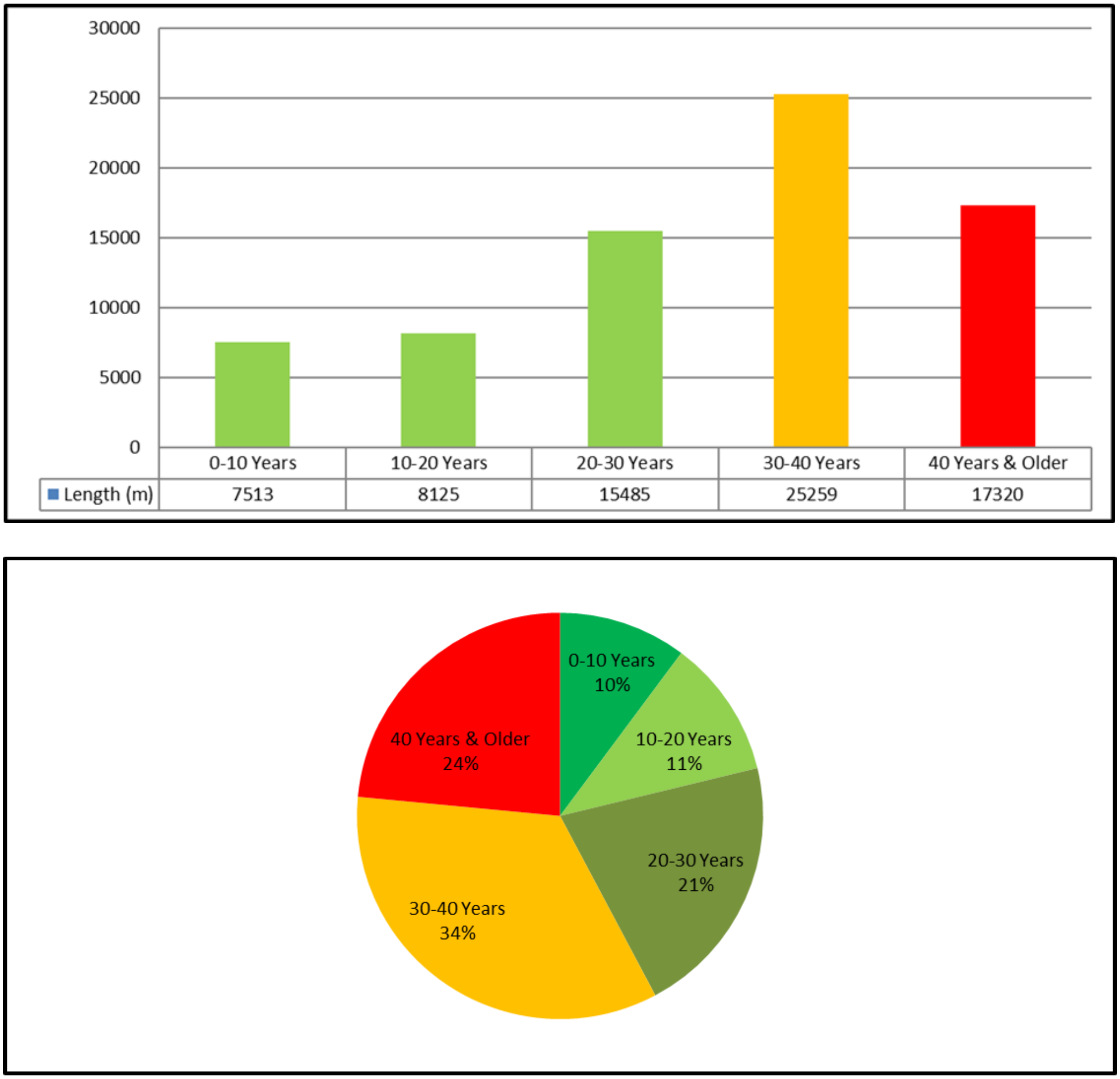
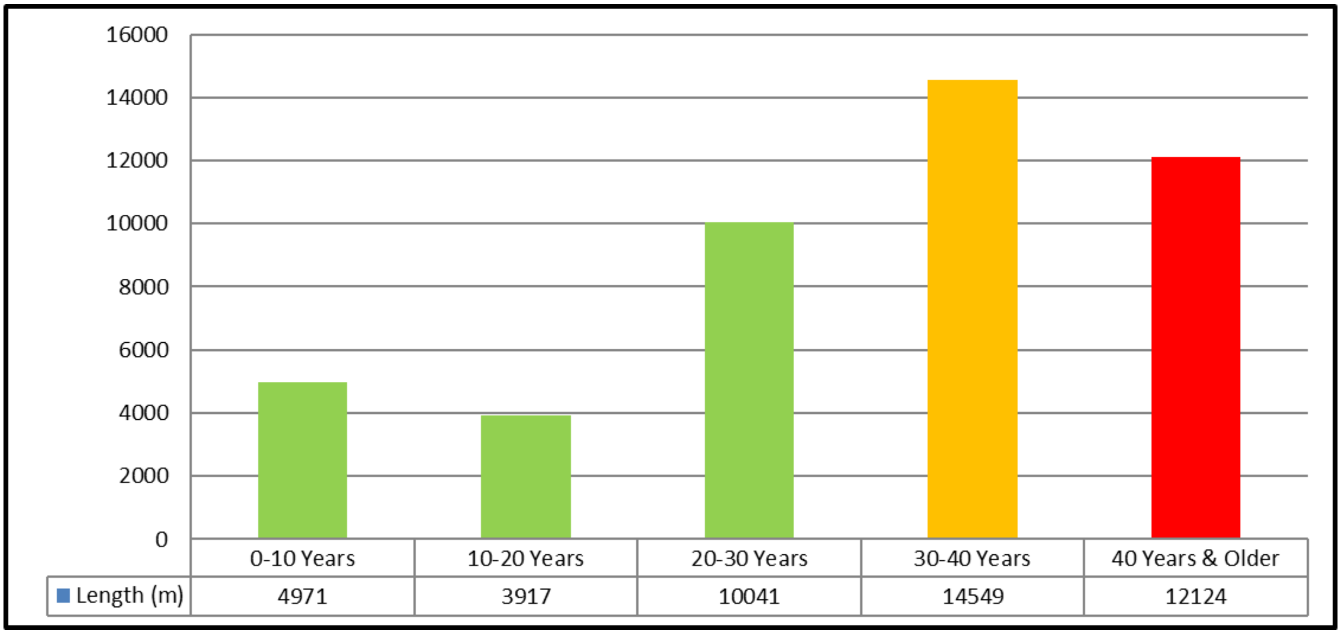


Figure 4-16: Age Profile – 34.5 kV and 12.47kV, 3-Phase Underground Cable Circuits



	0-10 Years	10-20 Years	20-30 Years	30-40 Years	40 Years & Older
■ Length (m)	4971	3917	10041	14549	12124

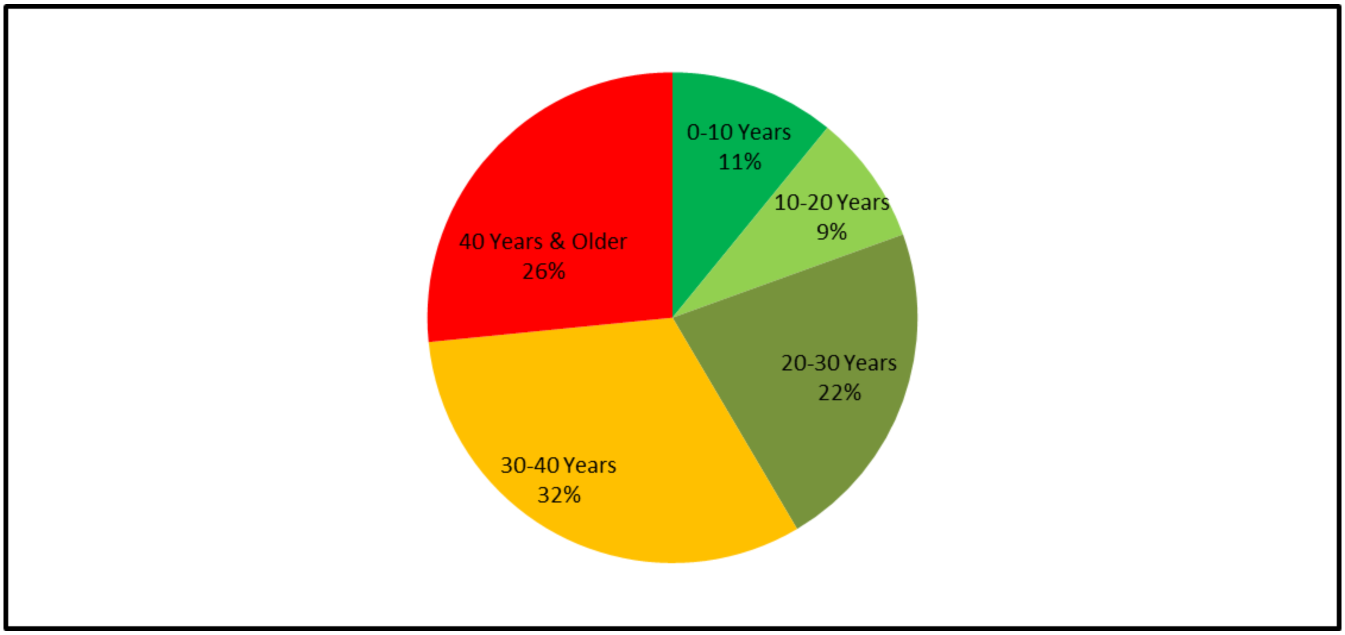
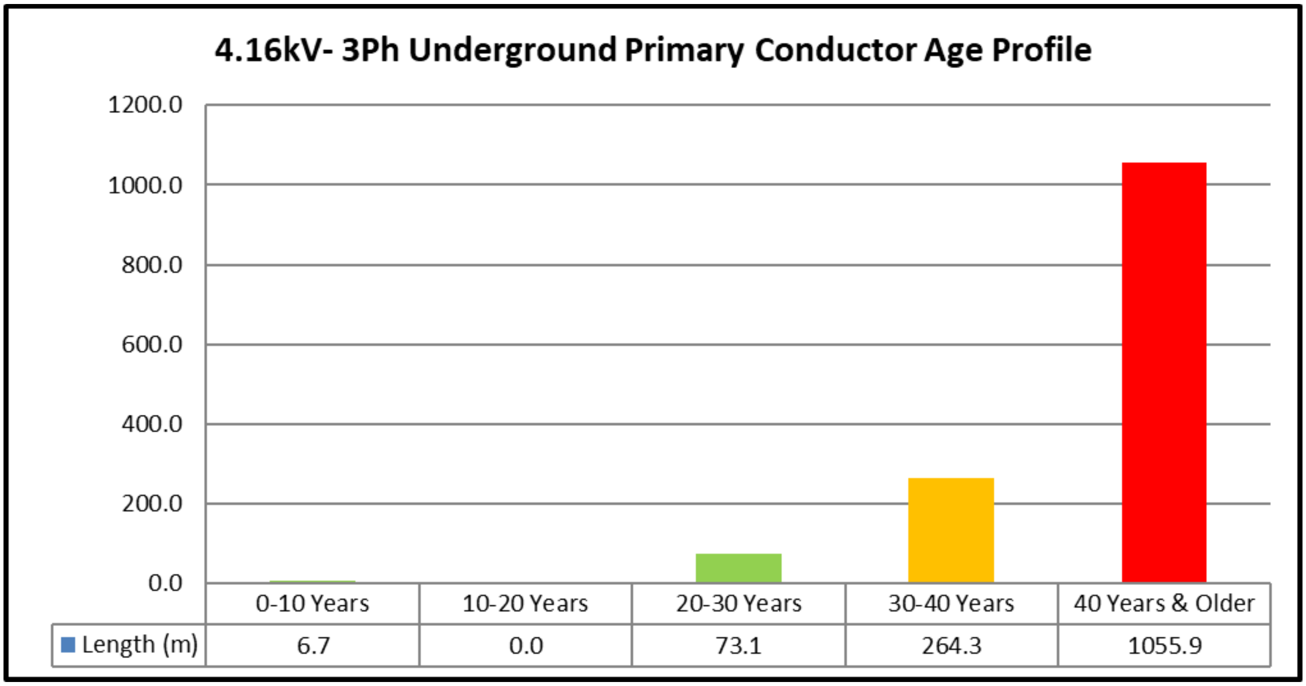


Figure 4-17: Age Profile – 12.47kV, 1-Phase Underground Cable Circuits



	0-10 Years	10-20 Years	20-30 Years	30-40 Years	40 Years & Older
Length (m)	6.7	0.0	73.1	264.3	1055.9

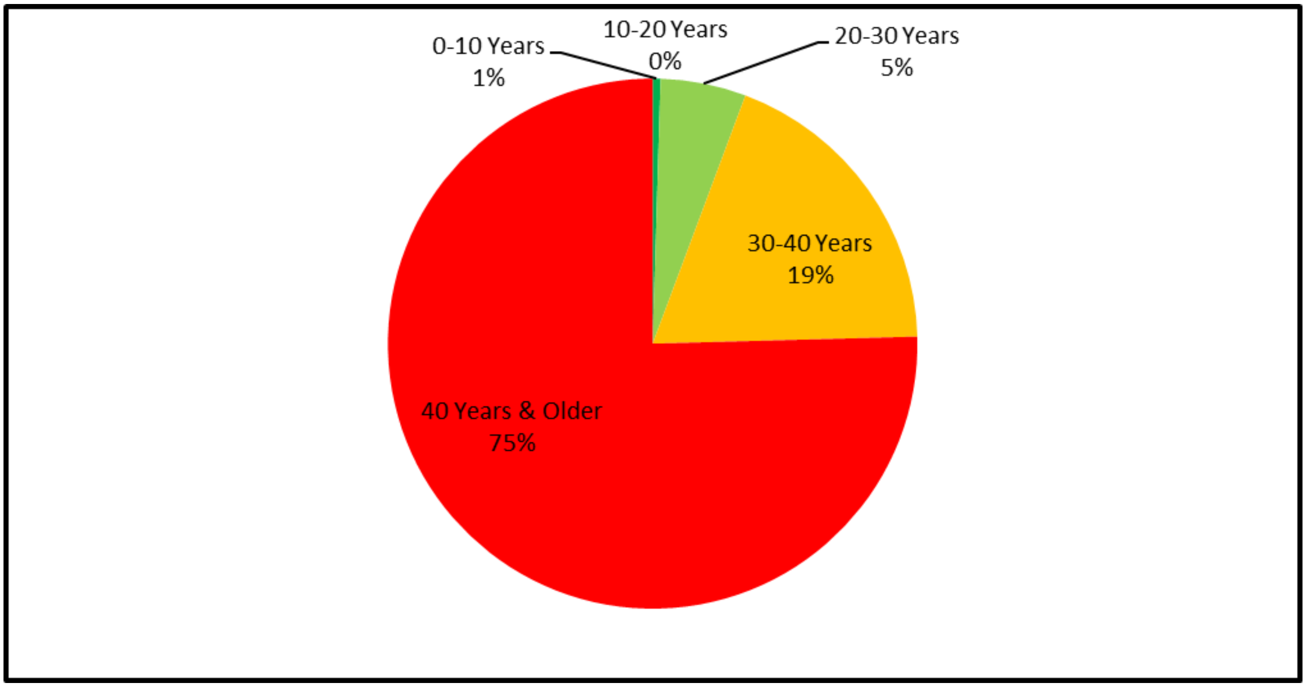
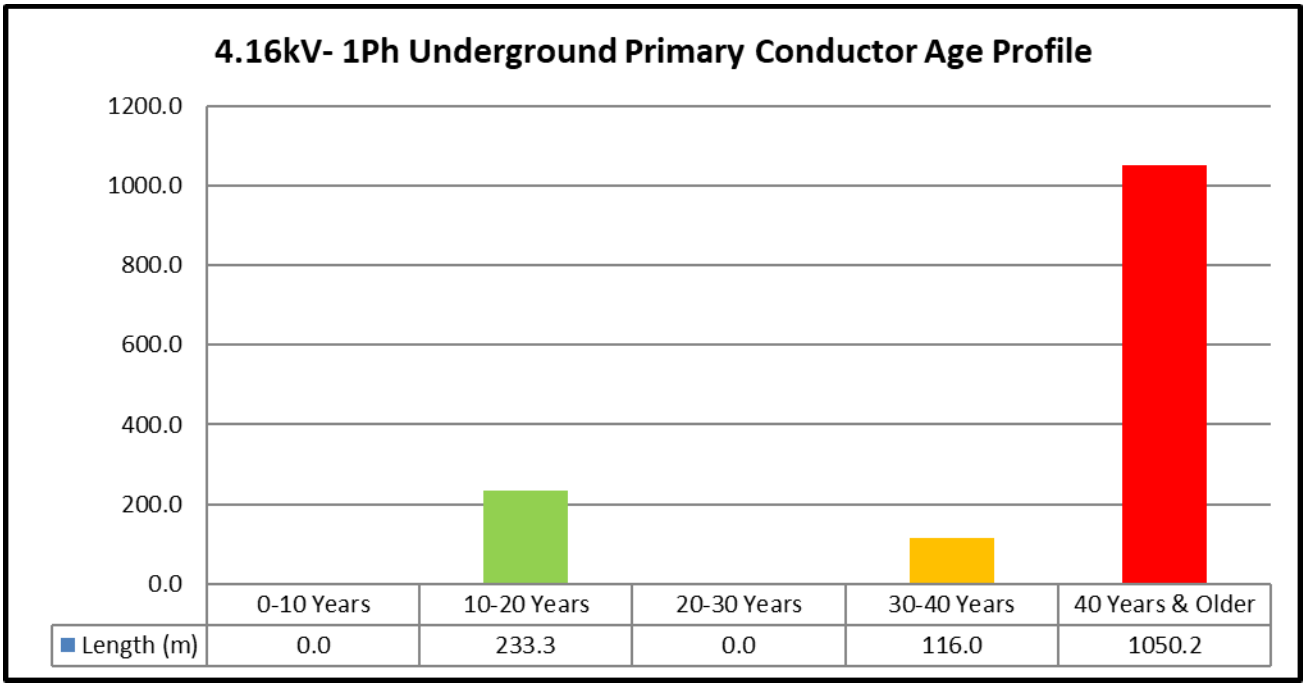


Figure 4-18: Age Profile – 4.16kV, 3-Phase Underground Cable Circuits



	0-10 Years	10-20 Years	20-30 Years	30-40 Years	40 Years & Older
Length (m)	0.0	233.3	0.0	116.0	1050.2

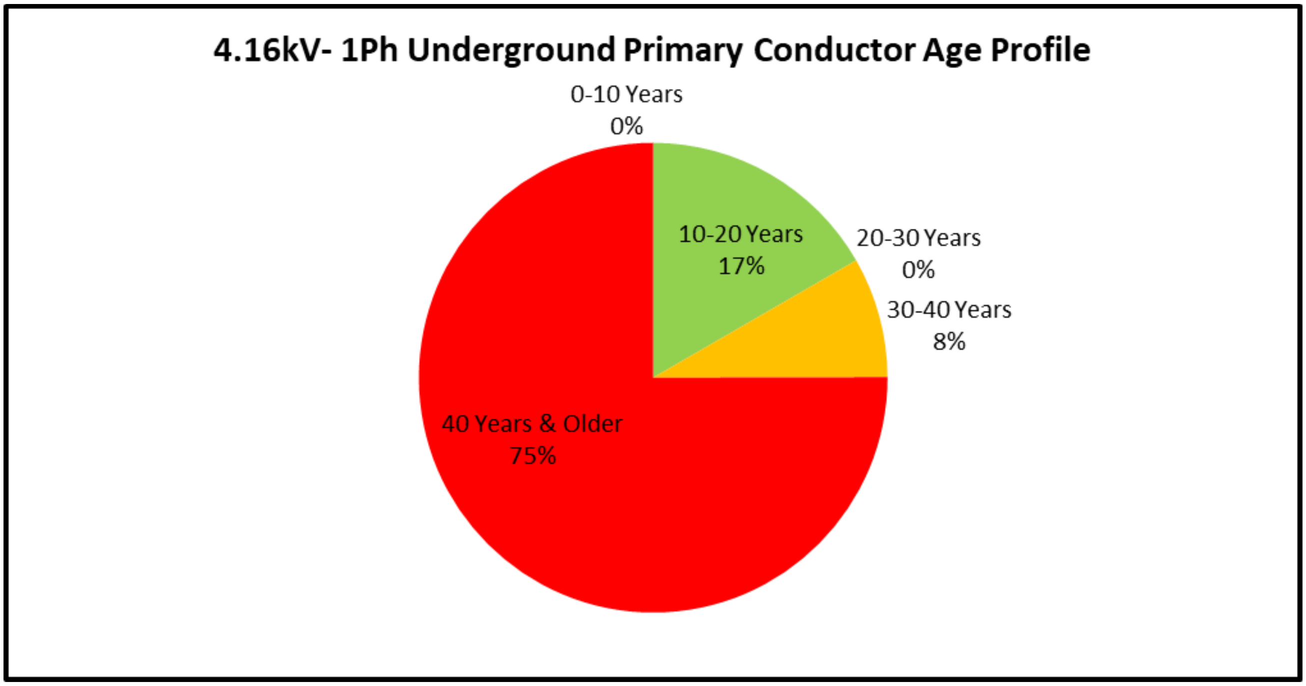


Figure 4-19: Age Profile – 4.16kV, 1-Phase Underground Cable Circuits

4.3.2. Pad-mounted Switchgear

At PUC DISTRIBUTION, live front pad-mounted switchgear, is the most commonly employed pad-mounted switchgear on underground distribution system, with a recent move towards dead front. Figure 4-20 indicates the age profile of pad-mounted switchgear. This type of switchgear provides reliable service life of about 35 years. Based on service age and visual inspections, 5 of the pad mounted switchgear units, are determined to be in poor or very poor condition, as shown in Figure 4-21.

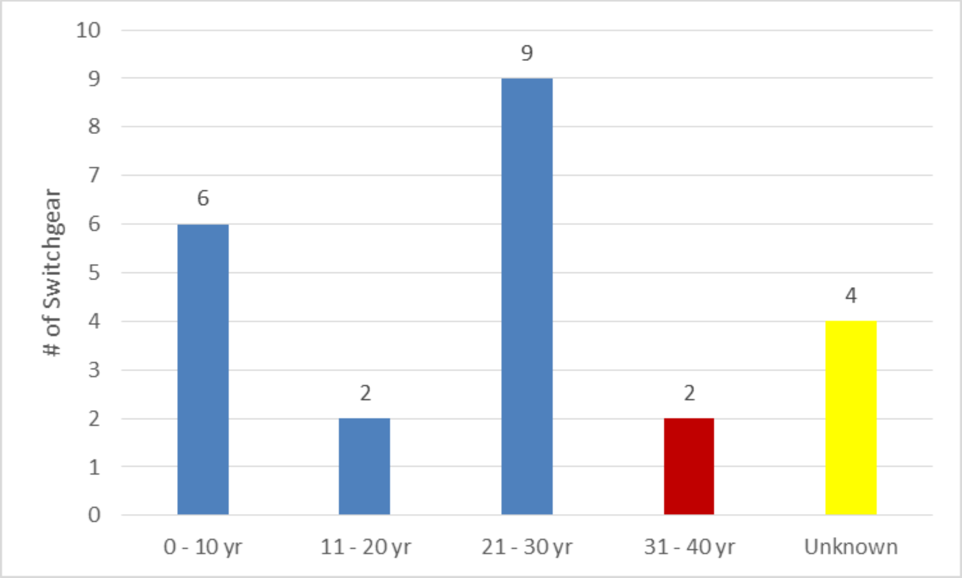


Figure 4-20: Age Profile – Pad-mounted Switchgear

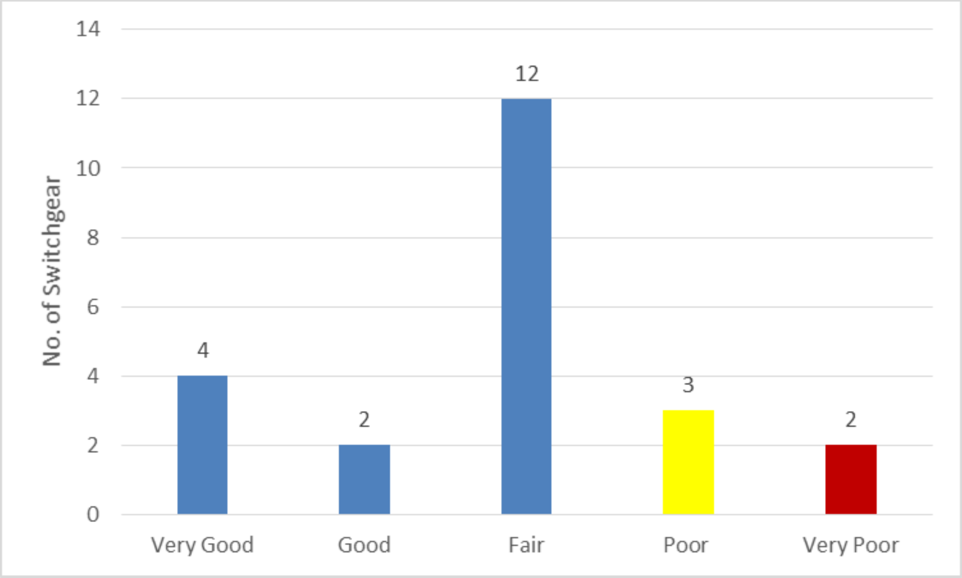


Figure 4-21: Condition Assessment of Pad-mounted Switchgear

Exact installation year for a majority of K-Bar junction boxes with service age of greater than 35 years is not known with certainty, but the estimated age profile for K-bar units is indicated in Figure

4-22. A majority of the junction boxes will reach the end of their typical service life of 40 years during the next five years.

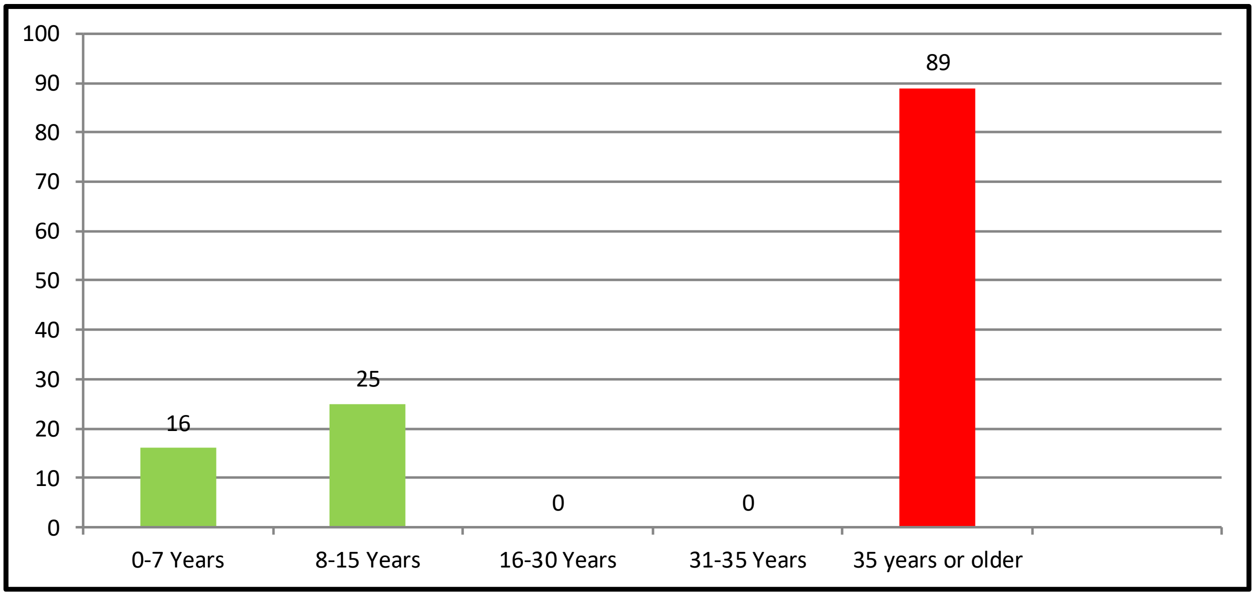


Figure 4-22: Age Profile – Pad-mounted K-Bar Units

4.3.3. Underground Concrete Chambers

PUC DISTRIBUTION's underground distribution system employs concrete chambers for various functions, including cable pull-boxes and manholes, mounting bases for switchgear and K-bar junctions, submersible transformer vaults, splice vaults and general-purpose equipment vaults. As shown in Figure 4-23, there approximately 23% of the chambers are currently more than 50 years old. Physical inspections of the concrete structures indicate, a large percentage of these old vintage chambers are functionally obsolete. From the point of view of worker safety, the submersible transformer vaults and splice vaults present a challenge in that outages are required to complete maintenance work increasing costs and inconveniencing customers.

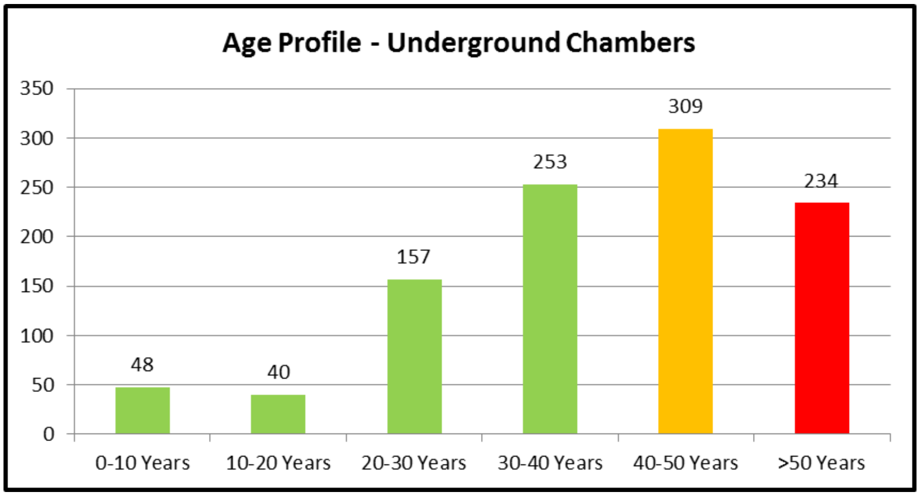


Figure 4-23: Age Profile of Underground Concrete Chambers

The submersible transformer vaults and splice vaults of inadequate size and without concrete floors, as shown in Figure 4-24, present the highest risk to workers and therefore, have been given a priority for reconstruction.

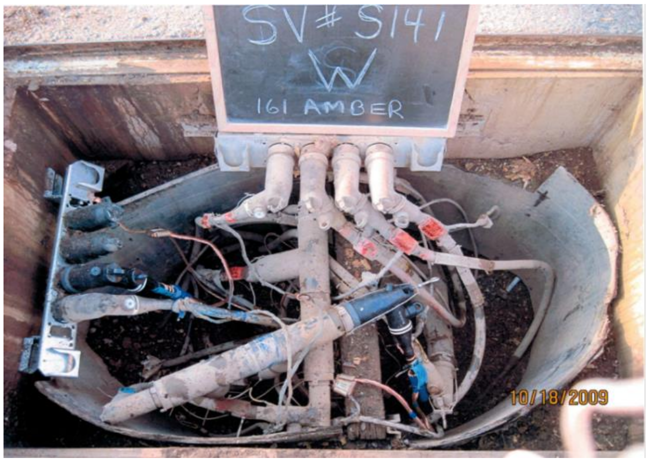


Figure 4-24: Underground Splice/Switching Vault

4.4. *Distribution Transformers*

PUC DISTRIBUTION has four different types of transformers in service: Pole-mounted, 1-phase Pad-mounted (mini-pad mount), 3-phase pad mounted and submersible vault type. Figure 4-25 through Figure 4-28 indicate the age profiles of transformers in each class.

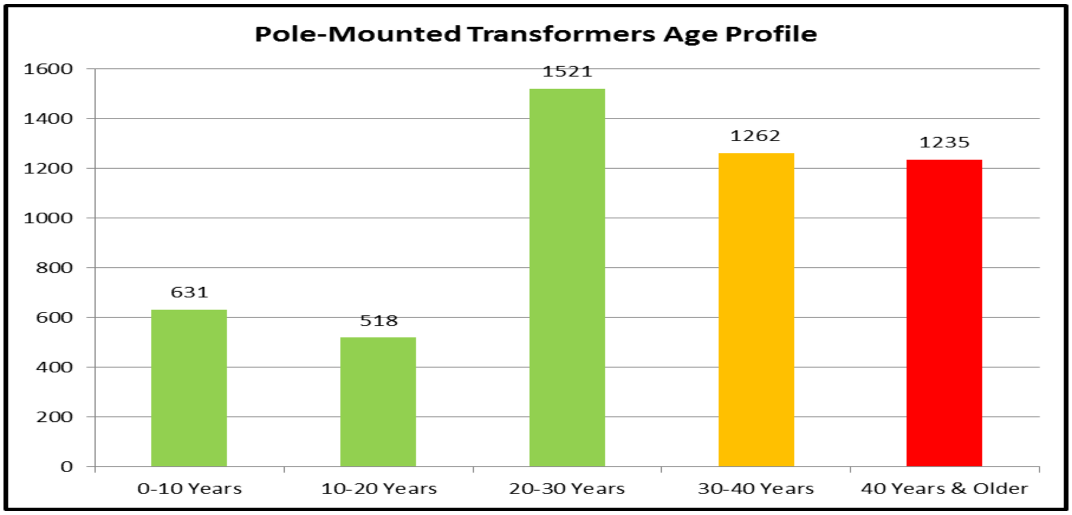


Figure 4-25: Pole Mounted Transformers – Age Profile

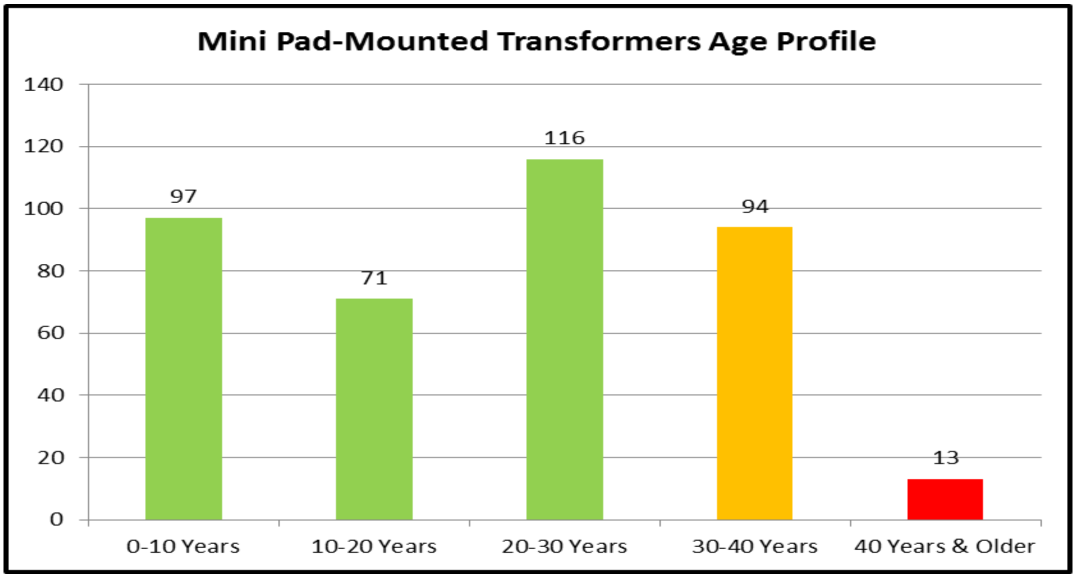


Figure 4-26: 1-Ph Pad-mounted Transformers – Age Profile

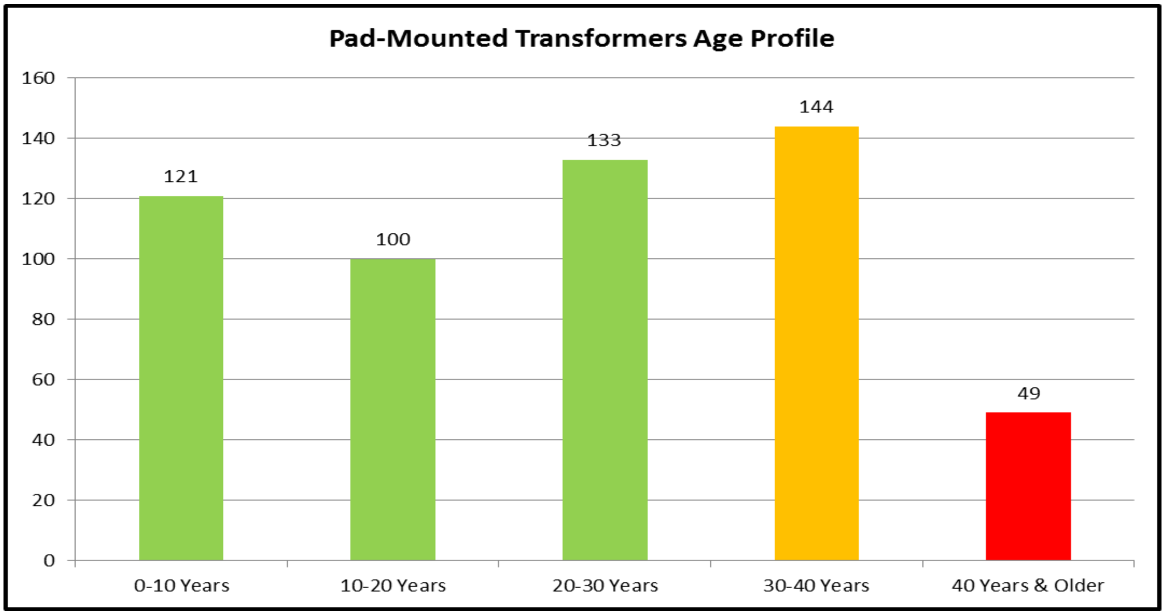


Figure 4-27: 3-Ph Pad-mounted Transformers – Age Profile

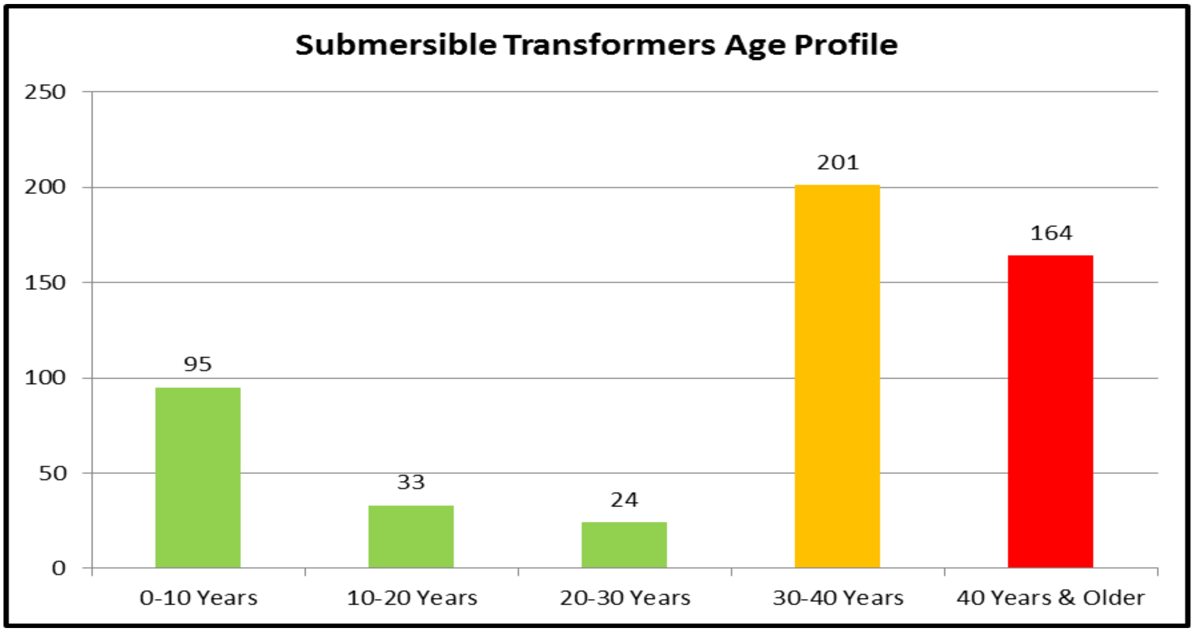


Figure 4-28: Submersible Vault Mounted Transformers – Age Profile

PUC DISTRIBUTION employs "run-to-failure" strategy for distribution transformers and due to the relatively low impact of transformer failures on reliability, this strategy serves well for the first three types of transformers and it is also in line with all other LDCs. However, because vault mounted transformers are not generally replaced with the same type of transformer upon failure, some degree of pre-planning is required to replace these with pad mounted transformers. Therefore, a proactive program is required to replace the submersible transformers with pad mounted transformers.

4.5. *Revenue Meters*

PUC DISTRIBUTION owns approximately 33,500 revenue meters, installed on its customers' premises for the purpose of measuring electric consumption, demand, and billing of connected load. The meters vary in type depending on the connection type and customer class, and are capable of measuring kWh consumption, for TOU customers, kW and KVA demand for GS >50, as well as bi-directional meters for renewable generation applications. PUC DISTRIBUTION completed the installation of all of its Residential and General Service <50kW Smart Meters by December 2010 as part of the Province of Ontario's mandated Smart Meter initiative.

Table 4-1: Revenue Meter Quantities

Customer Type	# of Customers
Residential	29708
GS<50	3419
GS>50	360
Total	33487

Table 4-1 shows the breakout of PUC DISTRIBUTION's active meters by customer/meter types. A vast majority of PUC DISTRIBUTION's electric meters were installed in 2009 and have a seal year of 2019. PUC DISTRIBUTION plans to sample 600 meters in 2019, 200 in 2020 and 80 in 2021 all in accordance with Measurement Canada's "S-S-05—Performance Requirements Applicable to Meters Granted a Conditionally Lengthened Initial Reverification Period under S-EG-01" - sample its meter population to acquire an extension of up to 8 years. It is planned on testing and recalibrating 50 three-phase meters in 2020.

PUC is also required to equip all general service customers with >50kW to <500kW demand with MIST meters

In addition, revenue meters will also be required to replace meters failed in service and the failure rate of revenue meters is expected to be approximately 0.6% per year.

In addition to the above, spare revenue meters would be required to replace meters that fail in service. Table 4-2 shows the revenue meter failures on PUC DISTRIBUTION's network during the past six years. As shown in Table 4-2, the average number of meter failures per year between 2009 and 2015 has been 216.

Table 4-2: Revenue Meter Failures

Year	Number of meter failures
2010	332
2011	332
2012	240
2013	102
2014	195
2015	92
Average number of failures per year	216

Table 4-3 summarizes the revenue meter requirements to facilitate replacement of meters failed in service as well as removal from service of the required batch size of revenue meters for calibration, prior to expiry of the meter seals. It is noteworthy that the meters purchased in 2017 to facilitate calibration check will be transferred to general inventory and will become available for replacement of failed meters in subsequent years.

Table 4-3: Revenue Meter Requirements

Year	2016	2017	2018	2019	2020	2021
1-phase meters to replace meters failed in service	220	220	220	220	220	220
1-phase meters required to facilitate recalibration				200		
3-phase meters to replace meters failed in service	5	5	5	5	5	5
3-phase meters required to facilitate recalibration					50	

5 ASSET INVESTMENT PLAN

Based on the results of condition assessment of major assets employed in step down stations, overhead lines and underground distribution system, described in detail in Section 4, this section provides the budgetary estimates of capital investment required during the next six years to replace and rebuild those assets, that present high risk of failure in service, posing a threat to supply system reliability, public and employee safety and operating efficiency.

5.1. Step-down Station Assets:

Since the in-service failure of power transformers and switchgear in step-down stations has the largest impact on power supply security and reliability, a long term proactive program is recommended to gradually reconstruct all of the stations, determined to be in poor or very poor condition.

Both of the 115/34.5 kV transformer stations (TS-1 and TS-2) will require rebuild during the next five to ten years. However to maximize the benefit/cost ratio of this major investment, significant front-end planning and engineering is required to successfully implement the rebuild of these stations. Therefore, we are recommending a planning/engineering study be commissioned to review all practical development options and identify the optimal option for implementation. For the 34.5 / 12.47 kV stations, we recommend at least two stations be included in the next five-year plan for rebuild, based on the condition of power transformers, switchgear and auxiliary equipment. Although the power transformers and switchgear at each of the three 4 kV distribution stations are also currently in poor and very poor condition, no provision is made in the investment plan for renewal of these stations, as these are recommended to be retired from service.

To minimize the risk of in-service equipment failures at the transformer stations and distribution stations, we recommend equipment condition be closely monitored through inspections and testing backed with repair and refurbishment, as required.

5.2. Overhead Distribution System:

Proposed investments into overhead distribution system, include re-construction of lines determined to be in "poor" and "very poor" condition. Because lines constructed with restricted conductors present a growing safety risk, it is recommended all 3-phase and 1-phase lines constructed with restricted conductors be rebuilt during the next eight to ten years. The five-year budget includes provision for rebuilding of 75% of all existing lines with restricted conductors. Proposed investment for line rebuilds also includes projects initiated through voltage conversion to facilitate retiring of the 4 kV stations as well as forced line rebuilds after failure of assets on existing lines. The investment plan also includes funding to replace poles found in poor and very poor condition during pole testing

5.3. Underground Distribution System:

Underground distribution cables in a number of subdivisions have reached a service age beyond their typical useful service life. Cables at the end of their useful life are expected to experience an increase in failure rates with adverse impact on reliability. Therefore, we recommend an increase in funding to replace or rejuvenate cables in this investment plan. The investment plan also includes funding for rebuilding of underground transformer vaults and splice vaults which present safety hazards to workers. Investment plan also includes funding for replacement of pad mounted switchgear and k-bar junction boxes found in poor condition.

5.4. Distribution Transformers:

For distribution transformers, a "run to failure" strategy is proposed, where a transformer is replaced only after failure. This Investment plan includes budgetary provisions to replace distribution transformers after they fail. Current PCB regulations in Canada permit the use of distribution transformers containing PCB content in oil of up to 50 parts per million and this use can continue up to December 31, 2025. All distribution transformers must be below 50 parts per million after December 31, 2025. To comply with this regulation, distribution utilities will need to either (a) test all suspect transformers (purchased prior to 1984) for PCB content and replace those containing PCBs above the threshold, or (b) replace all suspect transformers (purchased prior to 1984). The five-year investment plan includes budgetary provision for testing suspect distribution transformers for PCB content.

5.5. Miscellaneous Assets:

Investment plan includes budgetary provision for purchase of revenue meters, required to replace revenue meters failed in service as well as for calibration of meters upon expiry of meter seals. A small and reasonable amount has also been included for tools and equipment and for capital repairs to office buildings.

Table 5-1 summarizes the overall scope of capital investments proposed for the next six years. The cost estimates are based on unit-cost in 2015, and include an allowance for inflation at an annual rate of 2%.

Table 5-1: Investment Plan (2017 to 2021)

System Component	Project Description	Units of Measurement	Quantity (2017 - 2021)	Unit Cost in 2016 $	Budget in 2016 $ (2017 to 2021)	Annual Cost in 2016 $	Inflation adjusted Expenditure in Each Year				
							2017	2018	2019	2020	2021
Overhead Lines	3-Ph Line rebuild - restricted conductor	m	3,100	$ 200	620000	$ 124,000	$ 126,480	$ 129,010	$ 131,590	$ 134,222	$ 136,906
	1-Ph Line rebuild - restricted conductor	m	22,100	$ 100	2210000	$ 442,000	$ 450,840	$ 459,857	$ 469,054	$ 478,435	$ 488,004
	3-Ph Line rebuild - voltage upgrade	m	3,000	$ 200	$ 600,000	$ 120,000	$ 122,400	$ 124,848	$ 127,345	$ 129,892	$ 132,490
	1-Ph Line rebuild - voltage upgrade	m	20,000	$ 100	$ 2,000,000	$ 400,000	$ 408,000	$ 416,160	$ 424,483	$ 432,973	$ 441,632
	3-Ph Line rebuild - Lines in poor/very poor condition	m	24,000	$ 200	$ 4,800,000	$ 960,000	$ 979,200	$ 998,784	$ 1,018,760	$ 1,039,135	$ 1,059,918
	1-Ph Line rebuild - Lines in poor/very poor condition	m	6,000	$ 100	$ 600,000	$ 120,000	$ 122,400	$ 124,848	$ 127,345	$ 129,892	$ 132,490
	Replace degraded poles	#	200	$ 7,500	$ 1,500,000	$ 300,000	$ 306,000	$ 312,120	$ 318,362	$ 324,730	$ 331,224
	Forced asset replacement upon Failures (capitalized repairs)	#	5	$ 250,000	$ 1,250,000	$ 250,000	$ 255,000	$ 260,100	$ 265,302	$ 270,608	$ 276,020
	Subtotal overhead lines				**$10,750,000**	**$2,150,000**	**$2,193,000**	**$2,236,860**	**$ 2,281,597**	**$ 2,327,229**	**$ 2,373,774**
Underground Distribution System	Replacement of 3-phase cables in poor/very poor condition	m	4,980	$ 360	$ 1,792,800	$ 358,560	$ 365,731	$ 373,046	$ 380,507	$ 388,117	$ 395,879
	Replacement of 1-phase cables in poor/very poor condition	m	6,420	$ 150	$ 963,000	$ 192,600	$ 196,452	$ 200,381	$ 204,389	$ 208,476	$ 212,646
	Rejuvenation of 3-phase cables (Silicone injection)	m	3,320	$ 180	$ 597,600	$ 119,520	$ 121,910	$ 124,349	$ 126,836	$ 129,372	$ 131,960
	Rejuvenation of 1-phase cables (Silicone injection)	m	4,280	$ 75	$ 321,000	$ 64,200	$ 65,484	$ 66,794	$ 68,130	$ 69,492	$ 70,882
	Replacement of 3-phase cables for voltage upgrade	m	1,300	$ 360	$ 468,000	$ 93,600	$ 95,472	$ 97,381	$ 99,329	$ 101,316	$ 103,342
	Replacement of 1-phase cables for voltage upgrade	m	1,150	$ 150	$ 172,500	$ 34,500	$ 35,190	$ 35,894	$ 36,612	$ 37,344	$ 38,091
	Pad-mounted switchgear replacement	#	5	$ 15,000	$ 75,000	$ 15,000	$ 15,300	$ 15,606	$ 15,918	$ 16,236	$ 16,561
	k-bar replacement	#	40	$ 8,000	$ 320,000	$ 64,000	$ 65,280	$ 66,586	$ 67,917	$ 69,276	$ 70,661
	Vault rebuilds	#	60	$ 12,500	$ 750,000	$ 150,000	$ 153,000	$ 156,060	$ 159,181	$ 162,365	$ 165,612
	Forced asset replacement upon Failures (capitalized repairs)	#	5	$ 300,000	$ 1,500,000	$ 300,000	$ 306,000	$ 312,120	$ 318,362	$ 324,730	$ 331,224
	Subtotal underground system				**$ 6,959,900**	**$1,391,980**	**$1,419,820**	**$1,448,216**	**$ 1,477,180**	**$ 1,506,724**	**$ 1,536,858**
Stations	TS Rebuild - Planning and Engineering		1	$ 800,000	$ 800,000			$ 208,080	$ 212,242	$ 216,486	$ 220,816
	MS Rebuild - 2 x 10/13 MVA	#	2	$4,000,000	$ 8,000,000			$4,161,600			$ 4,416,323
	Protection Relay and SCADA miscellaneous capital upgrades	#	1	$ 400,000	$ 400,000	$ 80,000	$ 81,600	$ 83,232	$ 84,897	$ 86,595	$ 88,326
	DC Control battery and charger upgrades	#	5	$ 100,000	$ 500,000	$ 100,000	$ 102,000	$ 104,040	$ 106,121	$ 108,243	$ 110,408
	Miscellaneous building, fence, yard repairs	#	3	$ 40,000	$ 120,000		$41,616.00		$ 43,297.29		$ 45,046
	Subtotal station investments				**$ 9,820,000**	**$ 180,000**	**$ 225,216**	**$4,556,952**	**$ 446,556**	**$ 411,324**	**$ 4,880,920**
Distribution Transformers	Pole mounted transformers	#	48	$ 5,000	$ 240,000	$ 48,000	$ 48,960	$ 49,939	$ 50,938	$ 51,957	$ 52,996
	Pad mounted 1-ph transformers	#	24	$ 7,500	$ 180,000	$ 36,000	$ 36,720	$ 37,454	$ 38,203	$ 38,968	$ 39,747
	Pad mounted 3-ph transformers	#	6	$ 18,000	$ 108,000	$ 21,600	$ 22,032	$ 22,473	$ 22,922	$ 23,381	$ 23,848
	Testing transformers for PCB contamination	#	1,375	$ 185	$ 254,375	$ 50,875	$ 51,893	$ 52,930	$ 53,989	$ 55,069	$ 56,170
	Subtotal Distribution Transformers				**$ 782,375**	**$ 156,475**	**$ 159,605**	**$ 162,797**	**$ 166,053**	**$ 169,374**	**$ 172,761**
Miscellaneous Assets	Revenue Meters 1-ph	#	1300	$ 145	$ 188,500	$ 37,700	$ 38,454	$ 39,223	$ 40,008	$ 40,808	$ 41,624
	Revenue Meters 3-ph	#	75	$ 600	$ 45,000	$ 9,000	$ 9,180	$ 9,364	$ 9,551	$ 9,742	$ 9,937
	Miscellaneous building upgrades	#	1	$ 60,000	$ 60,000	$ 12,000	$ 12,240	$ 12,485	$ 12,734	$ 12,989	$ 13,249
	Miscellaneous tools and equipment	#	1	$ 150,000	$ 150,000	$ 30,000	$ 30,600	$ 31,212	$ 31,836	$ 32,473	$ 33,122
	Subtotal Miscellaneous investments				**$ 443,500**	**$ 88,700**	**$ 90,474**	**$ 92,283**	**$ 94,129**	**$ 96,012**	**$ 97,932**
Total Capital Investments Requirements into asset renewal					**$28,755,775**	**$3,967,155**	**$4,088,114**	**$8,497,108**	**$ 4,465,516**	**$ 4,510,663**	**$ 9,062,246**

6 PREVENTATIVE MAINTENANCE PLAN:

We have reviewed the fixed asset preventative maintenance program currently in use at PUC DISTRIBUTION and determined that it is in line with the best utility practices. However, PUC DISTRIBUTION is currently in the process of installing an under-frequency loads shedding system (UFLS) in accordance with IESO requirements. Upon placing this system in service, maintenance requirements at the 12kV distributions stations will need to be increased in accordance with regulatory requirements. The existing preventative maintenance program is briefly described below:

(a) Assets installed in transformer stations and distribution stations are inspected and maintained in accordance with the schedule shown in Table 6-1.

Table 6-1: Substation Preventative Maintenance Program

Activity	Description	Frequency	Supporting Documents
Oil Testing	Oil sample are drawn from station transformers and sent for analysis. The results are reviewed and an action plan is established	Annually	Oil test results and summaries
Infrared Scanning	Infrared scanning is performed on various stations and Line equipment annually.	Annually	Exception reports and equipment lists
Battery Maintenance	Quarterly Inspection and testing of the inter-cell connections	Quarterly	Battery test results
ESA Inspections	Inspection by ESA Inspectors of stations and equipment.	1/3 of the stations annually	Inspection results
General Inspections	Inspection by Stations staff to ensure property security, proper operation and other physical aspects.	Monthly for distribution stations, weekly for Transformer Stations	Inspection Orders
Station Maintenance	Cleaning, testing Inspection and Maintenance of relays, breakers, switchgear, transformers, buss work, motor operators, switches etc. to meet NPCC requirements	5 year rotation (3 stations annually)	Inspection and test results

Oil Breaker inspection and Maintenance	Inspection and maintenance of the oil-filled circuit breakers at our two transformer stations, includes oil testing, removal of the tank, electrical and visual inspection of contacts, bushing testing etc.	5-year cycle	Inspection and test results
115 KV Switch Inspection and Maintenance	Inspection and maintenance of the 115 KV switches including alignment of the operating mechanism, lubrication, inspection of contact surfaces etc.	5- year cycle	Inspection and test results

(b) Overhead lines and underground pads and vaults are inspected on a 3-year cycle, to comply with Distribution System Code regulations. One third of the distribution assets employed on overhead distribution system are inspected each year. Structural defects, clearance issues and electrical problems and hazards are identified through visual inspections and where problems are revealed, either repair work is scheduled or capital work is planned, as needed. Where the inspections determine an immediate hazard immediate follow up action is taken to mitigate the problem. Field inspection records are kept on file in the line department until the next cycle of inspections.

(c) On overhead distribution lines, the following deficiencies/defects are identified on various assets:

Poles/Supports:

- Bent, cracked or broken poles
- Excessive surface wear or scaling
- Loose, cracked or broken cross arms and brackets
- Woodpecker or insect damage, bird nests
- Loose or unattached guy wires or stubs
- Guy strain insulators pulled apart or broken
- Guy guards out of position or missing
- Grading changes, or washouts
- Indications of burning

Distribution Transformers:

- Paint condition and corrosion
- Phase indicators and unit numbers match operating map (where used)
- Leaking oil
- Flashed or cracked insulators
- Contamination/discolouration of bushings
- Ground lead attachments

- Damaged disconnect switches or lightning arresters
- Ground wire on arresters unattached

Switches and Protective Devices:

- Bent, broken bushings and cutouts
- Damaged lighting arresters
- Ground wire on arresters unattached

Hardware and Attachments:

- Loose or missing hardware
- Insulators unattached from pins
- Conductor unattached from insulators
- Insulators flashed over or obviously contaminated (difficult to see)
- Tie wires unraveled
- Ground wire broken or removed
- Ground wire guards removed or broken

Conductors and Cables:

- Low conductor clearance
- Broken/frayed conductors or tie wires
- Exposed broken ground conductors
- Broken strands, bird caging, and excessive or inadequate sag
- Insulation fraying on secondary

Third Party Plant:

- Attachment not secure
- Infringing on clearances
- Compromising access to electrical equipment
- Unapproved/unsafe occupation or secondary use

General Conditions & Vegetation:

- Leaning or broken “danger” trees
- Growth into line of “climbing” trees
- Accessibility compromised
- Vines or brush growth interference (line clearance)
- Bird or animal nests

(d) On underground distribution lines, the following deficiencies/defects are identified on various assets:

Pad Mounted Transformers and Switching Kiosks:

- Paint condition and corrosion
- Placement on pad or vault
- Check for lock and penta bolt in place or damage
- Grading changes
- Access changes (Shrubs, trees, etc.)
- Phase indicators and unit numbers match operating map (where used)
- Leaking oil
- Lid damage, missing bolts, cabinet damage
- Cable connections
- Ground connections
- Nomenclature
- Animal nests/damage
- General conditions

Right of Way

- Accessibility compromised
- Grade changes that could expose cable
- Excessive vegetation on right of way

(a) Tree trimming has been carried out on a 3–year cycle in the past, which we consider to be satisfactory.

(b) In accordance with the best utility practices, thermograph inspections of distribution assets are carried out with infra-red cameras and any hot spots are promptly attended. The thermograph inspections appear to be extremely effective in detecting incipient faults and we recommend these should be continued as part of the maintenance program.

PHOTOGRAPHS OF STATION ASSETS

TS1

TS2

Substation #1

Substation #2

Substation #4

Substation #10

Substation #11

Substation #12

Substation #13

Substation #15

Substation #16

Substation #18

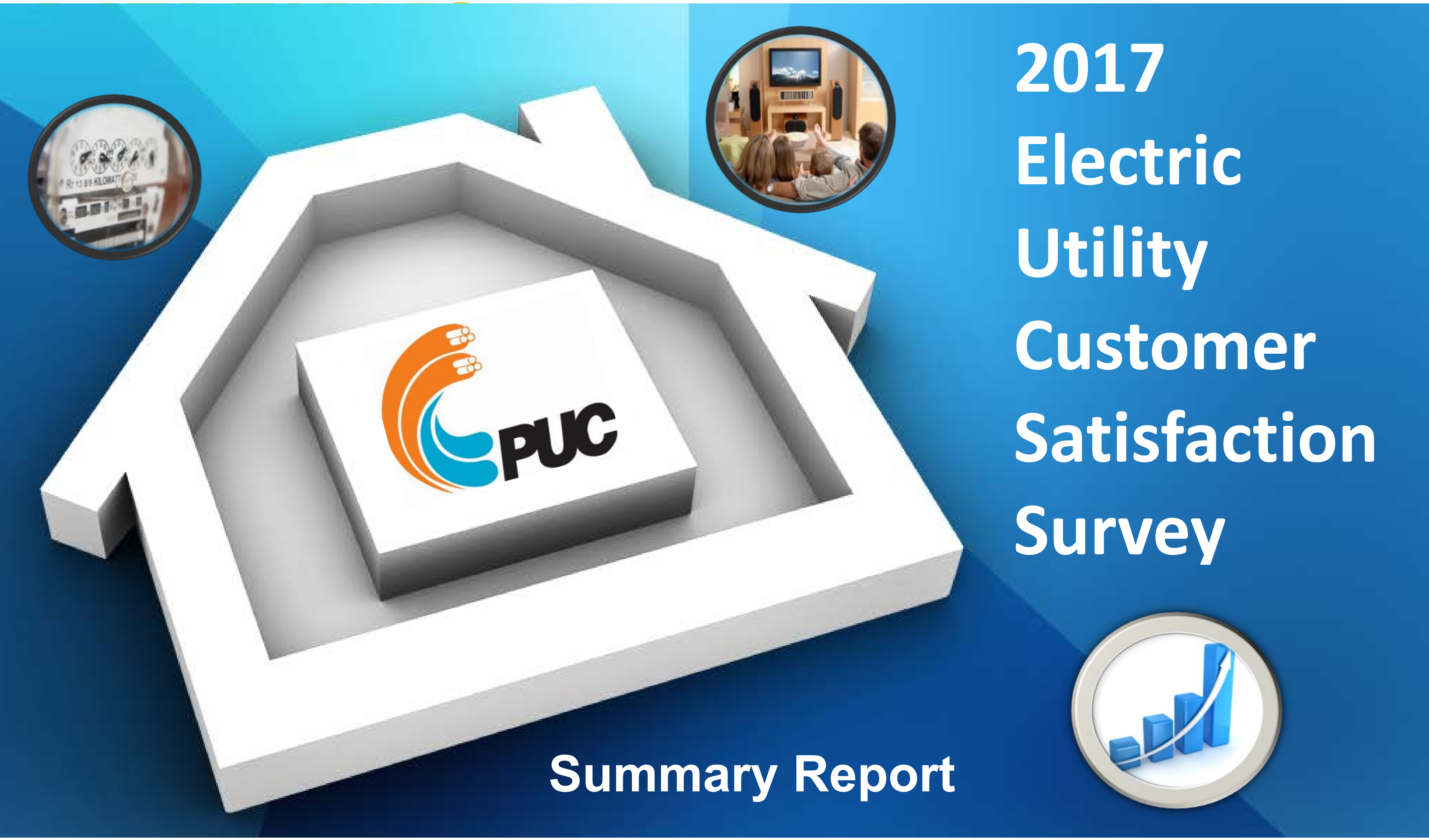
Substation #20

Substation #21

Appendix C

PUC Distribution Customer Satisfaction Survey

PUC Distribution Inc.



2017 Electric Utility Customer Satisfaction Survey

Summary Report

UtilityPULSE

The purpose of this report is to profile the connection between PUC Distribution Inc. (PUC Distribution) and its customers.

The primary objective of the Electric Utility Customer Satisfaction Survey is to provide information to support discussions about improving customer care at every level in your utility.

The UtilityPULSE Report Card® and survey analysis contained in this report do not merely capture state of mind or perceptions about your customers' needs and wants - the information contained in this survey provides actionable and measurable feedback from your customers.

This is privileged and confidential material and no part may be used outside of PUC Distribution Inc. without written permission from UtilityPULSE, the electric utility survey division of Simul Corporation.

All comments and questions should be addressed to:

Sid Ridgley, UtilityPULSE division, Simul Corporation

Toll free: 1-888-291-7892 or Local: 905-895-7900

Email: sidridgley@utilitypulse.com or sridgley@simulcorp.com

Survey Observations & Insights

In the 19 years UtilityPULSE has been conducting research in Ontario's LDC market, we have not seen the residential/small commercial customer base as negative – and some would say angry – as it is right now. Over the past 10 weeks UtilityPULSE has completed 6,000+ Residential and Small Commercial customer surveys – satisfaction results are ugly. Though not news to your call-centre professionals, more customers are worried about the cost of electricity and more customers are finding it difficult to pay their bill. This survey does ask respondents to pick from 3 statements the one which best describes their ability to pay. In 2015, 59% [Ontario Benchmark] and 55% [PUC Distribution] selected *"Paying for electricity is not really a worry"*, in 2017 the numbers are 53% [Ontario Benchmark] and 51% for PUC Distribution. Survey respondents are looking through the lens of costs, more specifically affordability, therefore ratings for 2017 have been impacted.

Ability to pay is a highly correlated factor to overall satisfaction, and given the steep rise in electricity costs (those costs beyond the control of your LDC), satisfaction is dropping. It is clear industry events are affecting how customers see your LDC. Customers have told us, despite spending money to assist in reducing consumption, their bill continues to go up. This double whammy is increasing the "worry" factor. We recommend everyone at PUC Distribution remain professional and demonstrate empathy and as we know about human nature, worry can easily turn into a severe erosion of trust which then leads to anger.

Though your survey is about gathering the opinions of your customers, the reality is, erosion of trust in institutions in other sectors is also contributing to the worry and angst factor your customers are experiencing – the good news is 78% of PUC Distribution's customers agree your LDC is trusted and trustworthy. Today’s heroes, when customers have problems or issues, are “everyday people” whose actions show they understand and are doing everything in their power to solve the problem. We’ve said this to our clients many times: “where understanding stops, stress, irritation, anger and conflict begin.”

Your survey was conducted from January 26 - February 24, 2017 and is based on one-on-one telephone interviews with individuals who pay or look after the electricity bill. Data for this report came from conducting a telephone interview with 401 of your residential and small commercial customers. In addition, survey findings for PUC Distribution have been enhanced with the inclusion of data from our UtilityPULSE database and the independently produced Ontario and National benchmarks.

Base: total respondents:
Top 2 Boxes: ”Strongly agree + agree”

Despite an angry environment towards the electricity industry as a whole, i.e., satisfaction levels and concern over costs; survey respondents gave PUC Distribution excellent operational scores.

Operational Attributes			
	PUC Distribution	**National**	**Ontario**
Provides consistent, reliable energy	91%	89%	89%
Quickly handles outages and restores power	90%	87%	85%
Accurate billing	81%	83%	80%

Base: total respondents with an opinion

However, PUC Distribution representatives also did their part:

Representative Attributes			
	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

Attributes strongly linked to Credibility & Trust			
	PUC Distribution	**National**	**Ontario**
Keeps its promises to customers and the community	76%	77%	73%
Pro-active in communicating changes and issues affecting Customers	77%	76%	73%
Is a trusted and trustworthy company	78%	81%	74%

Base: total respondents with an opinion

We have seen a social shift in the customer base, wherein there is a high expectation they will be involved in the decisions affecting them. The higher the intensity of worry that people have about their future, the higher the likelihood they will want a say in the things which could affect them.

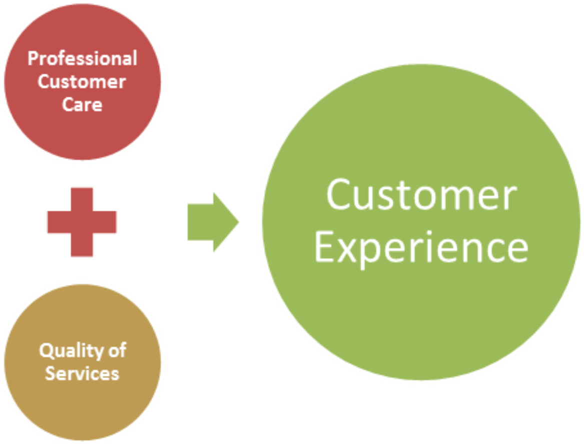
As such human beings will primarily act out of self-protection and self-interest which, in-turn, causes polarization of views. For LDCs it becomes much more difficult to generate a consensus view for items that are clearly in the best interest of the majority. Asking people who are very worried about paying their bill to support items which promote the “greater good” is a daunting task.

Customer engagement is not about getting agreement (though it would be nice to do so), customer engagement is about ensuring there is an understanding of customer wants and needs; particularly when the possibility of an increase in cost is involved.

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

Base: total respondents

Engagement is how customers think, feel and act towards the organization. Ensuring customers respond in a positive way requires they be rationally satisfied with the services provided AND emotionally connected to the LDC and its brand.



The Customer Experience Performance rating (CEPr) score is an effectiveness rating and is affected by many dimensions of service. Every touch point with customers on the phone, website or in-person influences what customers think and feel about the organization. While an excellent transaction today creates a positive experience today, the perception created is, future transactions will be excellent too.

Of course a negative transaction creates the perception, future transactions will be negative.

Customer Experience Performance rating (CEPr)

	PUC Distribution	National	Ontario
CEPr: all respondents	83%	82%	80%

Base: total respondents

Customer satisfaction is one dimension for measuring the effectiveness of an enterprise. But focusing on customer satisfaction as a sole measure is not enough to gain a picture about how well an operating unit/enterprise might be doing. Customer satisfaction as a measure is an effectiveness measure (not an efficiency measure) on the historical relationship or delivery of services to customers.

“Satisfaction happens when an enterprise’s core services meet or exceed customer’s needs, wants, or expectations.”

Customer Satisfaction

SATISFACTION SCORES – Electricity customers’ satisfaction

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

Customer Commitment

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’ would continue**	72%	78%	69%

Base: total respondents

Customer Advocacy

Electricity customers’ loyalty – … is a company that you would recommend to a friend or colleague

	PUC Distribution	**National**	**Ontario**
Top 2 boxes: **‘Definitely + Probably’ would recommend**	67%	71%	59%

Base: total respondents

It could be said, some problems can actually anger customers. As a mnimum, a problem is an inconvenience to the customers – and they want it solved/resolved. When the problem is solved with the first interaction (often called first call resolution) overall customer satisfaction can improve.

Problems: Power Outages

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

Problems: Billing issues

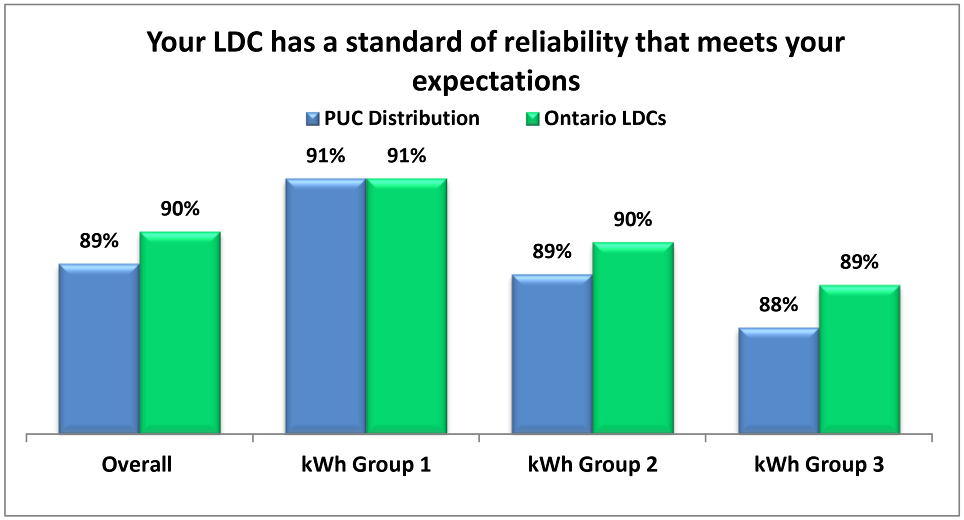
Percentage of Respondents indicating that they had a Billing problem in the last 12 months			
	PUC Distribution	**National**	**Ontario**
2017	25%	15%	25%
2016	-	9%	15%
2015	13%	16%	25%
2014	-	8%	10%
2013	-	12%	13%

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

Outage Management

The perception of competency and value of the LDC are certainly linked to the frequency and duration of power outages. Recognizing the importance of this topic to customers, a question about LDC reliability standards was asked in the survey.

Scores for PUC Distribution indicate the vast majority of customers feel the utility is consistent in meeting their expectations.


Your LDC has a standard of reliability that meets your expectations

Base UtilityPulse Database / total respondents

If the utility were to improve reliability should they put more emphasis on reducing the number of unplanned outages or reducing the duration of the unplanned outage? Or both which requires an increase in costs and potentially rates. Dealing with the pain of high bills is far and away more important to customers than the pain of outages which explains the high percentage (55%) of not willing to pay more.

However, this survey was completed prior to the Ontario Government's March 2, 2017 announcement about reducing electricity bills by 25%.

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

PUC Customer respondents give PUC Distribution excellent ratings as it relates to the job/task of dealing with outages.

LDC effectiveness responding to outages: Top 2 Boxes: "Very + Somewhat effective"		
	PUC Distribution	**Ontario LDCs**
Responding to the power outage	92%	85%
Restoring power quickly	94%	86%
Using media channels for updates	69%	54%
Providing information about the outage	72%	61%

Base: total respondents/ 2017 UtilityPULSE Database

Customer Service

Satisfaction with Customer Service			
Top 2 Boxes: ‘very + fairly satisfied’	**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 who contacted the utility

Everyone in the LDC affects a customer’s perception, not just call-centre employees. Employees in other departments interact with customers and so do outside-workers. Employees, at all levels and departments of the LDC are not immune to the frustration and anger customers feel about their bills and the industry as a whole. Therefore, it is imperative everyone remain professional and focused on doing everything very well – including the little things.

Upset or angry people are critical people and they will look for behaviours which reinforce or validate their negative view. It is more important than ever to ensure every interaction with a customer is an excellent one. Demonstrating understanding through active listening is a good start.

UtilityPULSE Report Card®

PUC Distribution's UtilityPULSE Report Card®

Performance

	CATEGORY	PUC Distribution	National	Ontario
1	**Customer Care**	**B**	**B**	**C+**
	Price and Value	C+	B	C
	Customer Service	B+	B+	B
2	**Company Image**	**B+**	**B+**	**B**
	Company Leadership	B	B+	B
	Corporate Stewardship	B+	B+	B
3	**Management Operations**	**A**	**A**	**A**
	Operational Effectiveness	A	A	B+
	Power Quality and Reliability	A+	A	A
	OVERALL	**B+**	**B+**	**B**

Base: total respondents

Lowest scoring attributes

Low scoring attributes			
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

Highest scoring attributes

High scoring attributes			
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

Use of Technology

Where will technology take us in the future? What effect will technology have on people's lives?

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

	PUC Distribution
Mostly better	39%
Mostly worse	9%
Neither	46%
Don't know	5%

Base: total respondents

As customers increasingly demand greater empowerment, utilities seek to improve interactions and relationships in their entire operation by enhancing software capabilities for collaboration, gaining deeper customer and market insight and improving process management. Respondents were asked how important having online access to the following features was to them:

Importance of online access for the following features:

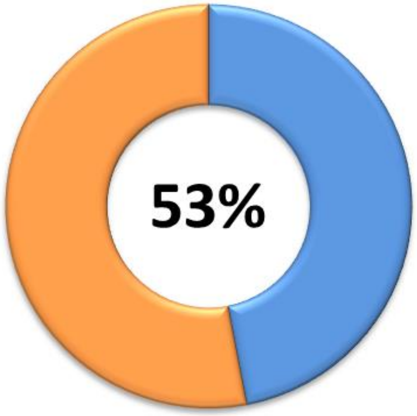
Top 2 Boxes: 'very + somewhat important'	PUC Distribution	UtilityPULSE Database
Reporting or inquiring about an issue	53%	71%
Researching information about energy conservation	58%	79%
Having a web chat feature on the website	32%	50%
Automated alerts when electricity usage exceeds a prearranged threshold	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

Confidence in the Industry

Respondents have a perception about the electricity industry as a whole. That image influences how people (customers) think and feel about various industry participants. Confidence represents a filter affecting customers' perception about their LDC. For example on the subject of customer satisfaction, the UtilityPULSE database shows those survey respondents who had high confidence levels scored 14% higher than those who had low confidence. This variance has little to do with the actual numbers or facts about the LDCs performance.

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



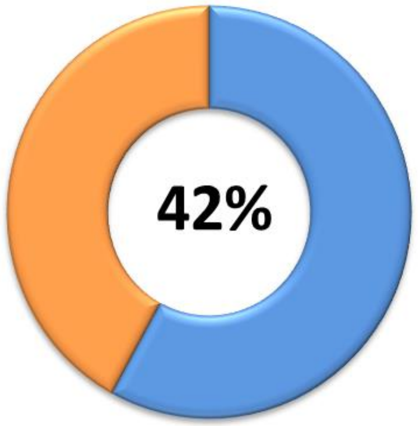
53% Agree ('strongly + somewhat') customers are well served by the electricity system in Ontario

5% neither agree nor disagree

39% Disagree ('strongly + somewhat') they are well served

1% did not render an opinion or did not know

‘Customers are confident in the electricity industry’s ability to meet their future expectations regarding quality, reliability and price’ – do you agree? Base: total respondents



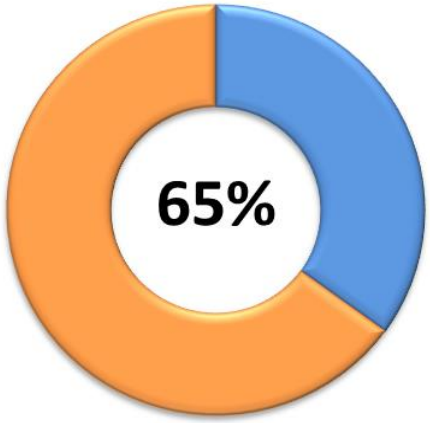
42% Agree (‘strongly + somewhat’) customers are confident the electricity industry has the ability to meet future expectations regarding quality, reliability and price

6% neither agree nor disagree

48% Disagree (‘strongly + somewhat’) the industry can deliver on future expectations

2% did not render an opinion or did not know

‘Customers are confident in the electricity industry’s ability to keep up with technological changes’ – do you agree? Base: total respondents



65% Agree (‘strongly + somewhat’) customers are confident the electricity industry is able to keep up with technological changes

7% neither agree nor disagree

23% Disagree (‘strongly + somewhat’) the industry will keep up with changing technology

4% did not render an opinion or did not know

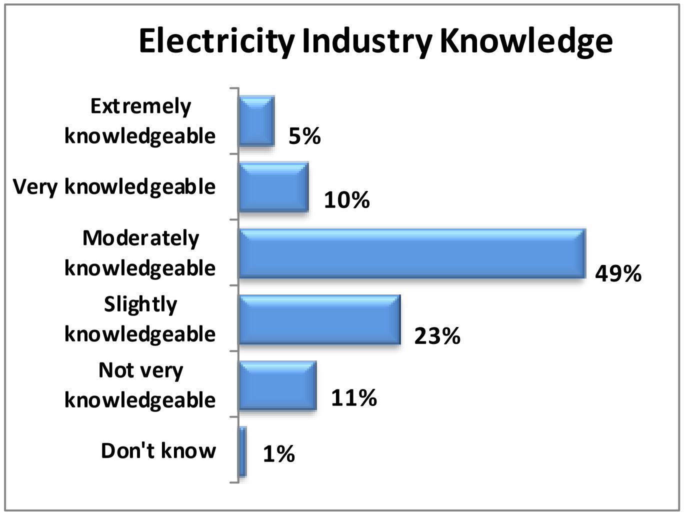
Electricity Industry Knowledge

16% of respondents for PUC Distribution described themselves as Extremely or Very knowledgeable about the electric utility industry. 49% claim they are moderately knowledgeable.

Approximately 1 in 5 (17%) survey participants in the UtilityPULSE database describe themselves as Extremely knowledgeable or Very knowledgeable. Only 50% of this knowledgeable group said they agree ‘strongly + somewhat’ customers were well served by the electricity system.

Approximately 1 in 3 survey respondents describe themselves in the bottom 2 categories of knowledge, and 58% of this group said they agree ‘strongly + somewhat’ customers are well served.

The data is clear; those who considered themselves more knowledgeable are also much less likely to say they have confidence in the industry to meet their needs and in the industry’s ability to keep up with technology. Being knowledgeable is not necessarily a path to better appreciation of the electricity industry. However it does seem to be a path which creates more polarization of viewpoints thereby making it more difficult to generate support for various items/activities.



Base: total respondents

Some customers will want to understand what is going on in the industry; just like there are some customers who want to know the inner workings of an automobile. However, the vast majority of people do not want to know how their automobile or the electricity industry works. What they want to know is, when there is a problem where they can access professionals who can fix them.

Loyalty Groups

Customer Loyalty Groups				
PUC Distribution	**Secure**	**Favorable**	**Indifferent**	**At Risk**
2017	19%	18%	44%	19%
2016	-	-	-	-

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

Paying for electricity

For 19 years, the highest factor correlated to satisfaction is ability to pay.

Is paying for electricity a worry or a major problem?				
	Not a worry	**Sometimes**	**Often**	**Depends**
PUC Distribution	51%	30%	17%	1%
National	65%	20%	12%	1%
Ontario	53%	25%	18%	1%

Base: total respondents

Confidence Prioritizing Investments

Survey respondents are looking through the lens of costs & affordability when providing answers to questions about investing in their LDC to ensure the reliable and safe delivery of electricity and the efficient running of operations. Understanding customer expectations, concerns, and desires does help an LDC to build their plans to ensure they remain relevant, viable, and valuable to customers, employees and other stakeholders.

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

Gathering support for making capital and operational investments is going to be a challenge for items other than those linked to replacing aging equipment to improve safety and reliability. This is where customer affinity plays an important role.

Loyal customers are more likely to see the world the way management sees it. Committed customers feel their interests and those of their utility are often in common. When customers are committed, they voluntarily tell others how they feel; they are more tolerant and more supportive. Relative to ‘good judgment to prioritize investments’, 85% of Secure and Favourable respondents are confident (‘very + somewhat’) that PUC Distribution is using good judgment to prioritize investments.

Capital Expenses

It is true, customers (but not all) can tell you what they want, but they have a very difficult time telling you what they need. On the one hand many customers **“want”** lower prices, but they **“need”** reliability and responsiveness.

Hence, it is up to the professionals in the LDC to use their experience and judgment to determine what needs to be done and when it should be done. No easy task – especially with a customer base that is focused on costs. Yet, about 2 out of 3 survey respondents opted for “pro-active replacement” which is consistent with the UtilityPULSE database average of 65%.

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

Which of the following CAPITAL items would you be willing to pay more for?

Preventive maintenance has been more popular in principle than in practice. It gets hard to argue with the idea of keeping equipment well maintained to extend its expected life and avoid future repair costs. Less clear is an understanding of the actual relationship between the cost of preventive maintenance and the returns such activities can be expected to deliver.

The following summarizes those respondents answering **‘yes’** they were willing to pay more for the listed capital expenditures:

- 69% - Replacing aging equipment to improve safety and reliability
- 50% - Upgrading equipment to accommodate future growth in the community
- 45% - Adding automation and technology to reduce outage time
- 37% - Investing in technology to deal with cyber security issues

Quantifiable data from the telephone survey about paying more for capital items indicates:

- 14% respondents were willing to pay more for 1 item
- 20% willing to pay more for 2 items
- 41% willing to pay more for 3 or 4 items
- 25% were not willing to pay more for any items.

Operating Expenses

PUC Distribution has to focus on day-to-day operations while it builds, re-builds, re-furbishes and prepares the organization for a changed future. In addition, LDCs need to think in terms of decades, not just today, this week, this month, or this quarter. They need to do so in a regulated environment that is a 5 year planning environment. Respondents were asked to identify the items they were willing to pay more for and, they were asked "how much" they would be willing to pay.

Which of the following items are you willing to pay more for per month …

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

Quantifiable data from the telephone survey about paying more for operational items indicates:

- 18% respondents were willing to pay more for 1 item
- 12% willing to pay more for 2 items
- 6% willing to pay more for 3 items
- 64% were not willing to pay more for any items.

Elasticity in willingness to pay more per month

It is true; self-interest will drive the choices people make. If an operational or capital item directly affects the respondent, then there is a willingness to support paying more per month. This indicates there is a need to be clear about what customers get from any additional cost – especially for the 3 operational items surveyed.

PUC Distribution customers, given the responses are through the lens of costs, are worried about the impact of additional costs will have on them. It is not the amount of the investment i.e., millions of dollars that the LDC may invest, but rather the impact of that investment on the customer i.e., dollars per month. .

About 1 in 4 customer respondents indicated they do not support any increase for any capital expense which is in line with the UtilityPULSE database, however 2 out of 3 customers are not willing to support any of the 3 operational items is significantly higher than the UtilityPULSE database average of 24%.

Numbers at a Glance

	PUC Distribution	National	Ontario
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

While electricity industry insiders could agree there has been a tremendous amount of change in the past 10-15 years the reality is, there is no let-up in sight. Shifts in demographics and customer expectations coupled with dramatic changes in how & where electricity is generated, stored and distributed will add to the to the level of challenge everyone in the LDC face.

Marketing communications need to be comprised of simple language elements which demonstrate the LDC understands the concerns and worries of customers, and shows the LDC is doing meaningful work to address those concerns and worries. In times of disruption or uncertainty, higher levels of customer affinity are the result of a corporate culture where PUC Distribution people feel empowered to act and are focused on the results which matter to all stakeholders.

In a polarized world, LDCs must consistently communicate their values to customers. Customer affinity grows when LDCs show they understand the worries, concerns and issues customers face because of the current state of the electricity market. A communication strategy demonstrating congruency with customer values will help build the brand and reputation of the LDC.

As we look into the future, and recognizing the high degree of attention the electricity industry is getting, we recommend the LDC review its processes and standards around activities/projects – and the supporting marketing communications - which could have an impact on customer perceptions regarding

the attributes of “easy to do business with”, “keeps its promises”, “pro-active communications”, “provides information to help customers reduce electricity costs”, “adapts well to changes in customer expectations”, “credibility & trust” and, “reliability”.

We recommend having meaningful two-way dialogue with employees (and others) to leverage the results from your 2017 customer satisfaction survey derived from speaking with 401 PUC Distribution customers [January 26 - February 24, 2017]. Thoughtful discussion turns data into information and insights which lead to benefits for all parties.

UtilityPULSE
Sid Ridgley
Simul/UtilityPULSE
Email: sidridgley@utilitypulse.com or sridgley@simulcorp.com
March 2017

Good things happen when work places work. You'll receive both strategic and pragmatic guidance about how to improve Customer satisfaction & Employee engagement with leaders who lead and a front-line which is inspired. We provide: training, consulting, surveys, diagnostic tools and keynotes. The electric utility industry is a market segment we specialize in. Both large and small utilities have received actionable insights. For 19 years we have been talking to 1000's of utility customers in Ontario and across Canada and we have expertise which is beneficial to every utility.

Culture, Leadership & Performance – Organizational Development	**Focus Groups, Surveys, Polls, Diagnostics**	**Customer Service Excellence**
Leadership development	Diagnostics ie. Change Readiness, Leadership Effectiveness, Managerial Competencies	Service Excellence Leadership
Strategic Planning	Surveys & Polls	Telephone Skills
Teambuilding	Customer Satisfaction and Loyalty Benchmarking Surveys	Customer Care
Organizational Culture Transformation	Organization Culture Surveys	Dealing with Difficult Customers

Benefit from our expertise in Customer Satisfaction, Leadership development, Strategy development or review, and Front-line & Top-line driven-change. We're experts in helping you assess and then transform your organization's culture to one where achieving goals while creating higher levels of customer satisfaction is important. Anyone can present data, or design programs – we believe having an understanding of the industry before doing so is crucial. Call us when creating an organization where more employees satisfy more customers more often, is important.

Your personal contact is:

Sid Ridgley, CSP

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

Appendix D

OPA/IESO Comment Letter on DSP

IESO Letter of Comment

PUC Distribution Inc.

Renewable Energy Generation Plan

December 21, 2017

Independent Electricity System Operator

Introduction

On March 28, 2013, the Ontario Energy Board (“the OEB” or “Board”) issued its Filing Requirements for Electricity Transmission and Distribution Applications; Chapter 5 – Consolidated Distribution System Plan Filing Requirements (EB-2010-0377). Chapter 5 implements the Board’s policy direction on ‘an integrated approach to distribution network planning’, outlined in the Board’s October 18, 2012 Report of the Board - A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach.

As outlined in the Chapter 5 filing requirements, the Board expects that the Ontario Power Authority[1] (“OPA”) comment letter will include:

- the applications it has received from renewable generators through the FIT program for connection in the distributor’s service area;
- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the Renewable Energy Generation (“REG”) investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

PUC Distribution Inc. – Renewable Energy Generation Plan

On November 30, 2017, the IESO received the REG Plan (“Plan”) of PUC Distribution Inc. (“PUC”) as part of its 5-year (2018-2022) Distribution System Plan. The IESO has reviewed the Plan and provides the following comments.

OPA FIT/microFIT Applications Received

The Plan indicates that PUC currently has approximately 63 MW of REG connected to its distribution system, and that over the Plan period it is capable of connecting all of its anticipated REG projects forecast to be a total of 1.25 MW of additional capacity.

According to the IESO’s information, as of November 30, 2017, the IESO has offered contracts to 107 microFIT projects, 9 FIT projects and 6 RESOP projects totalling approximately 62 MW of capacity, all of which have reached commercial operation. The difference in renewable energy generation connections information in PUC’s Plan, compared to the IESO’s information, is that PUC has an additional four Net Metering/Load Displacement projects that do not have contracts with the IESO.

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[1] On January 1, 2015, the Ontario Power Authority (“OPA”) merged with the Independent Electricity System Operator (“IESO”) to create a new organization that will combine the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator.

Consultation / Participation in Planning Meetings; Coordination with Distributors / Transmitters / Others; Consistency with Regional Plans

For regional planning purposes, the IESO notes that PUC is part of the East Lake Superior Region (Group 2).

Status of Regional Planning

As part of the OEB's Regional Planning Process the transmitter Great Lakes Power Transmission LP (now Hydro One Sault Ste. Marie) led the Needs Assessment Report for the region which was completed in 2014. The final report recommended that the issues identified in the area did not require further regional coordination. As a result of this recommendation, the IESO was not required to pursue the development of an Integrated Regional Resource Plan ("IRRP").

The IESO notes that PUC participated as part of the Needs Assessment study team along with Hydro One Networks Inc. (Transmission), the former Ontario Power Authority, the former IESO, Algoma Power Inc., and Chapleau Public Utilities Corporation.

With respect to REG investments, Section 4 of the Plan outlined the analysis done to conclude that over the Plan period, PUC's system shows no concerns caused by local or regional issues that should constrain additional growth of REG as projected. As a result, PUC has not included any associated infrastructure investment for the 2018-2022 period.

While the regional planning process for this area is now complete, it is expected to commence again in 2019 based on the OEB's 5-year cycle, unless there is an event that triggers the need for the process to begin earlier.

The IESO appreciates the opportunity to comment on the REG information provided by PUC Distribution Inc. as part of its 5-year Distribution System Plan.

Appendix E

Regional Infrastructure Planning Report

NEEDS ASSESSMENT REPORT

East Lake Superior Region

Revision: FINAL R0
Date: December 12, 2014

Prepared by: East Lake Superior Region Study Team

Great Lakes Power Transmission

ONTARIO POWER AUTHORITY

hydro one

ieso
Power to Ontario.
On Demand.

PUC DISTRIBUTION

Algoma Power Inc.
A FORTIS ONTARIO Company

CHAPLEAU PUBLIC UTILITIES CORPORATION

DISCLAIMER

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the East Lake Superior Region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Assessment Report may be studied further through subsequent regional planning processes and may be re-evaluated based on the findings of further analysis. The load forecast and results reported in this Needs Assessment Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Great Lakes Power Transmission LP (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Needs Assessment Report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the Needs Assessment Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the Needs Assessment Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

NEEDS ASSESSMENT SUMMARY REPORT

NEEDS ASSESSMENT SUMMARY REPORT

NAME	East Lake Superior Region Study		
LEAD	Great Lakes Transmission LP (GLPT)		
REGION	East Lake Superior		
START DATE	October 12, 2014	**END DATE**	December 12, 2014

1. INTRODUCTION

The purpose of this Needs Assessment report is to undertake an assessment of the East Lake Superior Region (ELS-Region), determine if there are regional needs that would lead to coordinated regional planning. Where regional coordination is not required and a “wires” only solution is necessary such needs will be addressed among the relevant Local Distribution Companies (LDCs), GLPT and other parties as required.

For needs that require further regional planning and coordination, the Ontario Power Authority (OPA) will initiate the Scoping process to determine whether an OPA-led Integrated Regional Resource Planning (IRRP) process or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution) is required, or whether both are required.

2. REGIONAL ISSUES/TRIGGER

The Needs Assessment for the East Lake Superior Region was triggered in response to the Ontario Energy Board’s (OEB) new Regional Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario’s 21 regions were assigned to one of three groups, where Group 2 Regions are to be reviewed in 2014. East Lake Superior Region belongs to Group 2 and the Needs Assessment for this Region was triggered on October 12, 2014 and was completed on December 12, 2014.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this Needs Assessment was limited to the next 10 years because relevant data and information was collected up to the year 2023. Needs emerging over the near-term (0-5 years) and mid-term (6-10 years) should be further assessed as part of the OPA-led Scoping Assessment and/or IRRP, or in the next planning cycle to develop a 20-year plan and strategic direction for the Region.

The assessment included a review of transmission system connection facilities capacity which covers station loading, thermal and voltage analysis, system reliability, operational issues such as load restoration and asset sustainment plans.

4. INPUTS/DATA (INFORMATION REQUIRED TO COMPLETE ASSESSMENT)

Study team participants, including representatives from Local Distribution Companies (LDC), the Ontario Power Authority (OPA), the Independent Electricity System Operator (IESO) and Hydro One Networks Inc. (Hydro One) provided information and input to GLPT for the East Lake Superior Region. The information provided includes the following:

- Actual 2013 regional coincident peak load, station non-coincident peak load and historical load provided by IESO;
- Historical net load and gross load forecast (which is the forecasted load from the historical net load) provided by LDCs and other Transmission connected customers;
- Conservation and Demand Management (CDM) and Distributed Generation (DG) data provided by OPA;
- Any known reliability and/or operating issues conditions identified by LDCs or the IESO;
- Planned transmission and distribution investments provided by the transmitter and LDCs, etc.

5. ASSESSMENT

The assessment’s primary objective over the study period (2014 to 2023) is to identify the electrical infrastructure needs in the region. The study reviewed available information, load forecast and conducted single contingency analysis to confirm need, if and when required. See Section 5 for further details.

6. RESULTS

A. 230kV Connection Facilities

- Based on the demand forecast, there is sufficient capacity at the one 230kV connected load station throughout the study period. No action is required at this time and the capacity needs will be reviewed in the next planning cycle.

- Based on the demand forecast over the study period, no overload or capacity need was identified for the loss of a single 230kV circuit in the region.

- East-West Tie lines are to be upgraded within the time period of this Needs Assessment. Hydro One’s Customer Impact Assessment (CIA) entitled “New East-West Tie Project’ dated October 29, 2014 concludes there are no significant impact to customer in the area.

B. 230/115kV Autotransformers

- No overload or capacity issues were identified for the loss of any single 230kV/115kV autotransformer except the overload of No.3 Sault for loss of MacKay TS T2 which is mitigated by arming the MacKay TS Generation Rejection Scheme.

C. 115kV Connection Facilities

- Based on the demand forecast, there is sufficient capacity at all 115kV load stations throughout the study period except Hollingsworth (T2) /Angijami (T1) TS's. The 44 kV system supplied by Hollingsworth TS T2 and Anjigami TS T1 will become overloaded due to a new large customer connecting to the 44 kV system late 2017.

- Loading on all 115 kV circuits is within assessment criteria limits throughout the study period except for the No.1, No.2 and No.3 Algoma lines that need to be studied further due to the increased demand forecast from one large industrial customer in Sault Ste. Marie projecting an increase in peak. This could be compounded in Sault Ste. Marie with the closure of Lake Superior Power Inc.'s LSP GS in 2014.

D. System Reliability, Operation and Restoration Review

- Generally speaking, there are no significant system reliability and operating issues identified for one element out of service in this region where there are two or more parallel elements.

- There is a concern about transformer failure in the region where there are some load stations with just one transformer supplying customer load. The Ontario Resource and Transmission Assessment Criteria (ORTAC) restoration criteria of 8 hours (plus travel time) cannot always be met for single transformer stations for a transformer failure. This is being studied at this time; however, it needs to be studied further.

E. Sustainment Replacement Plans

Significant sustainment activities are scheduled within the study period at the stations listed. The new equipment ratings at these stations were considered in this need assessment. Plans to replace major equipment do not affect the needs identified based on the demand forecast.

GLPT Stations
- Anjigami TS (equipment & relaying)
- Batchawana TS (equipment)
- Clergue TS (equipment)
- D.A. Watson TS (equipment)
- Goulais Bay TS (equipment)
- Hollingsworth TS (relaying)
- HWY 101 TS (relaying)
- Magpie TS (equipment)
- Steelton TS (equipment)

PUC Stations
- St. Mary's TS (equipment & relaying)

- Tarentorus TS (equipment & relaying)

7. RECOMMENDATION

The Team Recommends:

The potential need identified for the Anjigami TS/ Hollingsworth TS does not require further regional coordination. The study team recommends that "localized" wire only solution continue to be developed in the near-term to adequately and efficiently address the above need through planning between GLPT and the impacted distributor.

The potential needs identified regarding the capacity of the Algoma lines and the Sault Ste. Marie possible issues with the shutdown of LSP GS do not require further regional coordination. The study team recommends that a "localized wire only solution be developed in the near-term to address the above need through planning between GLPT and the impacted customer.

The potential need identified for the restoration of load (ORTAC 8 hours violated) after a single supply transformer failure does not require further regional coordination. The study team recommends that a "localized" wire only solution be developed by GLPT and the impacted distributor.

PREPARED BY: East Lake Superior Region Study Team

PARTICIPANTS: LISTED BELOW

COMPANY	**NAME**
Great Lakes Power Transmission LP (Lead)	**Jim Tait**
Ontario Power Authority	**Bob Chow**
Independent Electricity System Operator	**Phillip Woo**
Hydro One Networks Inc. (Transmitter)	**Ajay Garg**
PUC Distribution Inc.	**Rob Harten**
Algoma Power Inc.	**Greg Beharriell**
Chapleau Public Utility Corporation	**Alan Morin**

TABLE OF CONTENTS

LIST OF FIGURES AND TABLES

1. INTRODUCTION

This Needs Assessment report identifies needs in the East Lake Superior Region ("ELS-Region"). For needs that require coordinated regional planning, the OPA will initiate the Scoping process to determine the appropriate regional planning approach. The approach can either be the OPA-led Integrated Regional Resource Planning (IRRP) process or the transmitter-led Regional Infrastructure Plan (RIP), which focuses on the development of "wires" solutions. It may also be determined that the needs can be addressed more directly through localized planning between the transmitter and the specific distributor(s) or transmission connected customer(s). The development of the Needs Assessment report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements.

This report was prepared by the ELS-Region Needs Assessment study team (Table 1) and led by the transmitter, Great Lakes Power Transmission LP (GLPT). The report captures the results of the assessment based on information provided by the Local Distribution Companies (LDCs), Ontario Power Authority (OPA), Hydro One Network Inc. and the Independent Electricity System Operator (IESO) to determine possible needs in the ELS-Region.

Table 1: Study Team Participants for ELS-Region

Company
Great Lakes Power Transmission LP (GLPT) (Lead Transmitter)
Ontario Power Authority (OPA)
Independent Electricity System Operator (IESO)
Hydro One Networks Inc. (Hydro One) (Transmitter)
PUC Distribution Inc. (PUC)
Algoma Power Inc. (API)
Chapleau Public Utility Corporation (CPUC)

Figure 1: East Lake Superior Region

2. REGIONAL ISSUE / TRIGGER

The Needs Assessment for the ELS-Region was triggered in response to the Ontario Energy Board's (OEB) new Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario’s 21 regions were assigned to one of three groups, where Group 2 Regions are to be reviewed in 2014. The ELS-Region belongs to Group 2. The Needs Assessment for this ELS-Region was triggered on October 12, 2014 and was completed on December 12, 2014.

Additional information about Regional Planning can be found on the GLPT website: http://www.glp.ca/content/regional_planning_new/history-40236.html

3. SCOPE OF NEEDS ASSESSMENT

This Needs Assessment covers the ELS-Region over an assessment period of 2014 to 2023. The scope of the Needs Assessment includes a review of system capability which covers transformer station loading and transmission thermal and voltage analysis based on recent detailed studies. Asset sustainment issues and other considerations were taken into account as deemed necessary.

3.1. EAST LAKE SUPERIOR REGION DESCRIPTION AND CONNECTION CONFIGURATION

Figure 2a – Wawa TS/Anjigami TS Northern Area – Hydro One 230/115 kV autotransformers at Wawa TS, Hydro One 115 kV circuit supplying CPUC load and GLPT 115 kV lines and stations connected via Anjigami TS.

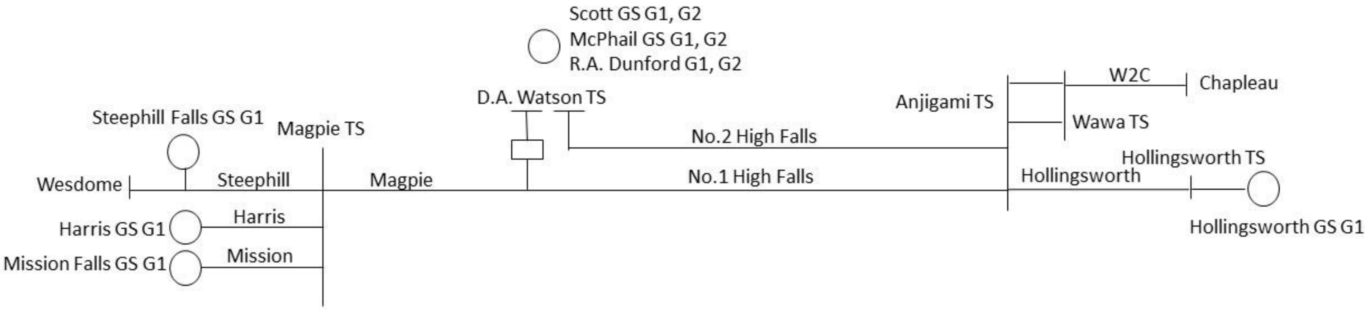


Figure 2b – MacKay TS South Central Area – GLPT 230/115 kV autotransformer at Mackay TS and 115 kV lines/stations connected via Mackay TS and two transformer stations connected to No.3 Sault.

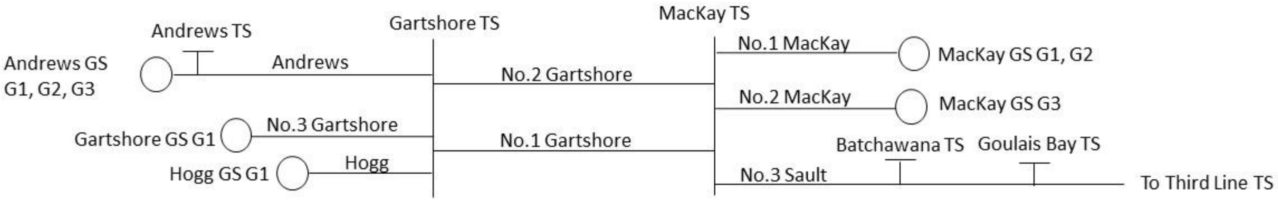


Figure 2c – Sault Ste. Marie Southern Area – GLPT 230/115 kV autotransformers at Third Line TS and 115 kV lines/stations in Sault Ste. Marie.

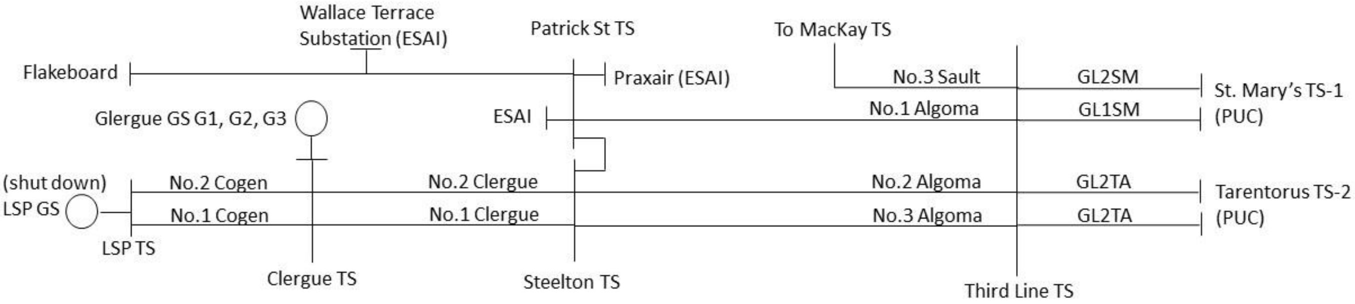
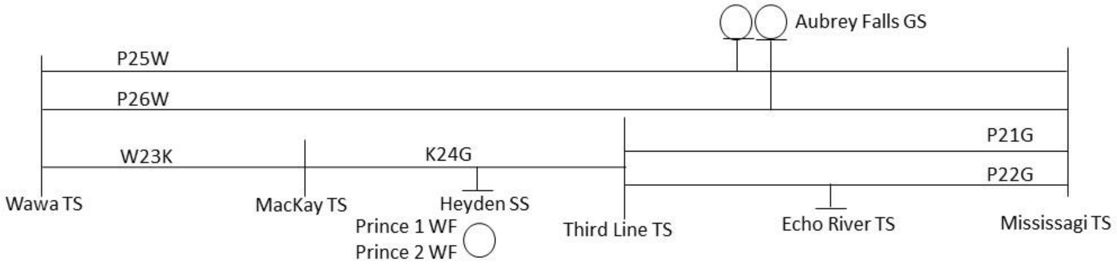


Figure 2d – GLPT and Hydro One 230 kV Eastern Area – Hydro One 230 kV lines P25W and P26W from Wawa TS to Mississagi TS, GLPT 230 kV lines W23K (Wawa TS to MacKay TS), K24G (MacKay TS to Third Line TS), P21G and P22G (Third Line TS to Mississagi TS) and one 230/34.5 kV transformer station connected to P22G.



4. INPUTS AND DATA

In order to conduct this Needs Assessment, study team participants provided the following information and data to GLPT:

- Actual 2013 regional coincident peak load, station non-coincident peak load and historical load provided by IESO;
- Historical net load and gross load forecast (which is the forecasted load from the historical net load) provided by LDCs and other Transmission connected customers;
- Conservation and Demand Management (CDM) and Distributed Generation (DG) data provided by OPA;
- GLPT provided transformer, station and line ratings
- Hydro One provided Wawa TS autotransformer ratings
- Any known reliability and/or operating issues conditions identified by LDCs or the IESO;
- Planned transmission and distribution investments provided by the transmitter and LDCs, etc.

4.1. LOAD FORECAST

As per the data provided by the LDCs, the load in the ELS-Region is expected to grow at a rate varying from -0.1% to 2.5% plus some larger customer load increases.

Table 2: Annual Load Growth for ELS-Region

LDC	**Approximate % Growth Rate 2013 to 2018**	**Approximate % Growth Rate 2019 to 2023**
PUC	Slightly Negative	Slightly Negative
API	0.0 to 2.5%	0.0 to 2.5%
CPUC	0%	0%

Large Industrial Customer Load Increases	**Approximate MW Increase 2013 to 2018**	**Approximate MW Increase 2019 to 2023**
Sault Ste. Marie Southern Area	19.4	3.2
Wawa TS/Anjigami TS Northern Area	20.85	0

The Needs Assessment considered gross loads at individual stations based on the 2013 summer or winter peak non-coincident load and the peak summer or winter load forecast for stations within the Region. The station load forecast was developed by using data provided by the LDC’s load forecasts and other customer load forecasts.

5. ASSESSMENT METHODOLOGY

The following methodology and assumptions were made in this Needs Assessment:

1. The Region is winter peaking, but this assessment includes both summer and winter peak loads where one is more critical than the other due to equipment ratings.

2. Forecast loads are provided by the LDCs and other customers.

3. Stations having negative load growth over the study period are assumed to have steady load.

4. In developing a worst-case scenario, DG and CDM contributions were not considered.

5. Review and assess impact of any on-going or planned development project in the ELS-Region during the study period.

6. Review and assess impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as autotransformers, cables and stations.

7. Station capacity adequacy is assessed assuming a 90% lagging power factor on the HV and non-coincident station loads.

8. Transmission line adequacy to be assessed using non-coincident peak station loads in the region.

9. The needs were first identified by looking at the total normal supply capacity (TNSC) of the elements that supply a specific LDC or other customer compared to the three month average peak over the last 5 years and the peak load over the last five years. This was used to identify any planning issues based on the existing peak loads. The 2023 peak load was then compared to the TNSC and if peak loads were greater than 75% of the TNSC for specific station/line(s), these station/line(s) were identified for further study. The TNSC takes into consideration one element out of service where load is not supplied via a single line/station.

10. Transmission adequacy assessment is primarily based on:

    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their continuous ratings and transformers within their summer 10-Day limited time ratings (LTR) if there are two transformers and 10 day LTR's exist.
    - All voltages and voltage declines must be within pre- and post-contingency ranges as per ORTAC criteria.

11. The ELS-Region has a considerable amount of hydro generation connected to the 115 kV system and wind generation connected to the 230 k system. Two new wind farms are in the process of connecting to the Gartshore 115 kV lines (58.3 MW) and K24G 230 kV lines (25.3 MW). Both have had recent detailed IESO System Impact Assessments (SIA) and GLPT Customer Impact Assessments (CIA) completed which did not identify concern in the area regarding overload of facilities. Generation in the area is generally more critical to line overload than LDC and other customer load. These studies were reviewed as part of this Needs Assessment process.

12. For the Sault Ste. Marie Southern section of the ELS-Region, the 98% dependability of generation from Clergue GS was used in this assessment. Glergue GS dependable generation was assumed to be 10 MW. This is based on an IESO Feasibility Study (Confidential) undertaken to assess the Algoma lines for adequate capacity.

This Needs Assessment was conducted to identify emerging needs and determine whether or not further coordinated regional planning should be undertaken for the Region or electrical areas. It is expected that further studies in the subsequent regional planning process will undertake detailed analysis and also assess ORTAC performance requirements.

6. RESULTS

6.1. Transmission Capacity Needs

6.1.1. 230kV Connection Facilities

Based on the demand forecast, there is sufficient capacity throughout the study period at Echo River TS which is a 230kV connected load station. No action is required at this time and the capacity needs will be reviewed in the next planning cycle.

Based on the demand forecast over the study period, no overload or capacity need was identified for the loss of a single 230kV circuit in the region.

East-West Tie lines are to be upgraded in 2019. Hydro One's CIA entitled "New East-West Tie Project' dated October 29, 2014 concludes there are no significant impact to customers in the area. The Hydro One CIA assessed the Short-Circuit Impact, Voltage Impact and Supply Reliability Impact.

6.1.2. 230/115kV Autotransformers

No overload or capacity issues were identified for the loss of any single 230kV/115kV autotransformer except the overload of No.3 Sault for loss of MacKay TS T2 which is mitigated by arming the MacKay TS Generation Rejection Scheme.

6.1.3. 115kV Connection Facilities

Based on the demand forecast, there is sufficient capacity at all 115kV load stations throughout the study period except Hollingsworth (T2) /Angijami (T1) TS's. The 44 kV system supplied by Hollingsworth TS T2 and Anjigami TS T1 will become overloaded due to a new large customer connecting to the 44 kV system late 2017.

Loading on all 115 kV circuits is within assessment criteria limits throughout the study period except for the No.1, No.2 and No.3 Algoma lines that need to be studied further due to the demand forecast from one of the other customer in Sault Ste. Marie projecting an increase in peak load. This could be compounded in Sault Ste. Marie with the closure of Lake Superior Power Inc.'s LSP GS in 2014.

6.2. System Reliability, Operation and Restoration Review

Generally speaking, there are no significant system reliability and operating issues identified for one element out of service in this region where there are two or more parallel elements.

There is a concern about transformer failure in the region where there are many load stations with just one transformer supplying customer load. The ORTAC restoration criteria of 8 hours (plus travel time) cannot always be met for single transformer stations for a transformer failure. This is being studied at this time; however, it needs to be studied further.

6.3. Sustainment Replacement Plans

Significant sustainment activities are scheduled within the study period at the stations listed. The new equipment ratings at these stations were considered in this need assessment. Plans to replace major equipment do not affect the needs identified based on the demand forecast.

GLPT Stations

- Anjigami TS (equipment & relaying)
- Batchawana TS (equipment)
- Clergue TS (equipment)
- D.A. Watson TS (equipment)
- Goulais Bay TS (equipment)
- Hollingsworth TS (relaying)
- HWY 101 TS (relaying)
- Magpie TS (equipment)
- Steelton TS (equipment)

PUC Stations

- St. Mary's TS (equipment & relaying)
- Tarentorus TS (equipment & relaying)

6.4. Other Considerations

Restoration of most of the GLPT transmission system can be accomplished from a black start procedure which energizes the Sault Ste. Marie Southern Area load/generation and eventually up to MacKay TS South Central Area to load/generation and run as an island. It is expected that for the loss of Wawa TS T1 and T2 transformers and by configuration the Wawa TS/Anjigami TS Northern Area, the delay in restoration of GLPT connected load/generation can be greater than the ORTAC standard of 8 hours. There is a need to study if this area could be operated as an island until the supply from Hydro One Wawa TS can be restored.

7. RECOMMENDATIONS

The study Team Recommends:

7.1. The potential need identified for the Anjigami TS/ Hollingsworth TS does not require further regional coordination. The study team recommends that "localized" wire only solution be developed in the near-term to adequately and efficiently address the above need through planning between GLPT and the impacted distributor.

7.2. The potential needs identified for the Algoma lines and the Sault Ste. Marie possible issues with the shutdown of LSP GS does not require further regional coordination. The study team recommends that a “localized” wire only solution be developed by GLPT and the impacted customer.

7.3. The potential need identified for the restoration of load after a single supply transformer failure which could violate the ORTAC criteria of restoring load within 8 hours does not require further regional coordination. The study team recommends that GLPT and the impacted distributor continue to work on this need.

8. NEXT STEPS

Following the Needs Assessment process, the next regional planning step, based on the results of this report, are:

8.1. GLPT and the relevant LDC’s are to further assess and/or develop local wires solution as identified in the needs outlined in Section 7.1 and 7.3.

8.2. GLPT and the relevant customers will further assess and/or develop local wires solution as identified in the needs outlined in Section 7.2.

9. REFERENCES

Planning Process Working Group (PPWG) Report to the Board

IESO Ontario Resource and Transmission Assessment Criteria (ORTAC)

IESO Feasibility Study (Confidential) for Algoma Lines Redevelopment

IESO System Impact Assessment (SIA) Report and Addendum Report for Bow Lake Wind Farm (CAA ID#: 2010-392)

IESO System Impact Assessment Report and Addendum Report for Goulais Wind Farm (CAA ID#: 2010-397)

GLPT Customer Impact Assessment (CIA) Report for RTK Canada, ULC (Rentech) increased 44 kV load dated April 23, 2014.

Customer Impact Assessment (CIA) Report for Hydro One New East-West Tie Project dated October 29, 2014.

10. KEY TERMS AND DEFINITIONS

Key terms and definitions associated with this Needs Assessment are cited here.

Normal Supply Capacity (NSC): The maximum loading that electrical equipment may be subjected to continuously under nominal ambient conditions such that no accelerated loss of equipment life would be expected.
Coincident Peak Load: The electricity demand at individual facilities at the same specific point in time when the total demand of the region or system is at its maximum.

Contingency: The prevalence of abnormal conditions such that elements of the power system are not available.

Conservation and Demand Management (CDM): Programs aimed at using more of one type of energy efficiently to replace an inefficient use of another to reduce overall energy use, and influencing the amount or timing of customers' use of electricity.

Distributed Generation (DG): Electric power generation equipment that supplies energy to nearby customers with generation capacity typically ranging from a few kW to 25 MW.

Gross Load: Amount of electricity that must be generated to meet all customers' needs as well as delivery losses, not considering any generation initiatives such as CDM and DG. It is usually expressed in MW or MVA.

Limited Time Rating (LTR): A higher than nameplate rating that a transformer can tolerate for a short period of time

Load Forecast: Prediction of the load or demand customers will make on the electricity system

Net Load: Net of generation (e.g. CDM and DG) deducted from the Gross load

Non-Coincident Peak Load: The maximum electricity demand at an individual facility. Unlike the coincident peak, non-coincident peaks may occur at different times for different facilities.

Peak Load: The maximum load consumed or produced by a unit or group of units in a stated period of time. It may be the maximum instantaneous load or the maximum average load over a designated interval of time.

Total Normal Supply Capacity (TNSC): The maximum loading that electrical equipment may be subjected to post contingency (n-1) under nominal ambient conditions such that an acceptable accelerated loss of equipment life would be expected. For a single element supply system the TNSC equals the NSC.

11. ACRONYMS

CDM Conservation and Demand Management

CIA Customer Impact Assessment

DG Distributed Generation

DSC Distribution System Code

IESO Independent Electricity System Operator

IRRP Integrated Regional Resource Planning

kV Kilovolt

LDC Local Distribution Company

LTR Limited Time Rating

LV Low-voltage

MVA Mega Volt-Ampere

MW Megawatt

NA Needs Assessment

NSC Normal Supply Capacity

OEB Ontario Energy Board

OPA Ontario Power Authority

ORTAC Ontario Resource and Transmission Assessment Criteria

PF Power Factor

PPWG Planning Process Working Group

RIP Regional Infrastructure Planning

SIA System Impact Assessment

SS Switching Station

TNSC Total Normal Supply Capacity

TS Transformer Station

TSC Transmission System Code

PUC SERVICES INC.
500 SECOND LINE EAST, P.O. Box 9000
SAULT STE. MARIE, ONTARIO, P6A 6P2

September 29, 2014

Great Lakes Power Transmission LP
Transmission System Planning
Asset Management and Engineering Dept.
2 Sackville Rd., Suite B
Sault Ste. Marie, ON
P6B 6J6

Attn: Jim Tait
Technical Supervisor Engineering

Cc: Claudio Stefano, V.P Operations & Engineering (PUC)

Re: OEB Regional Infrastructure Planning (RIP) Process
Information for Needs Screening Process

Dear Mr Tait,

We are providing the following submission in response to your letter dated 2014/08/12 in which you request information to support the needs screening portion of the Regional Infrastructure Planning process. In that letter you request:

1. Gross and Net Load forecast for the next 10years, provided on the following basis:
    a. In megawatts ("MW") with power factor assumptions provided;
    b. At the supply Transformer station or delivery point
2. Regional system reliability and performance issues.
3. Any additional information considered relevant.

Historical and Forecast loading is summarized in the attached spreadsheet which was completed on the standard Load Forecast Template file provided by GLPT. Supporting information is also included to substantiate our assumptions. This information consists of:

- Conservation demand management information in form of email from CDM Officer dated 2014/09/19, entitled ‘2011-2013 CDM Demand Savings’
- Metering data extracted from wholesale metering points in the form of a spreadsheed, filename ‘0509.6 OEB RIP2014-09-25 load Forecast.xlsx’

In general terms, based on the forecast, we do not see any near term needs for a change in capacity of the 115kV transmission assets connecting our LDC to your transmission system. Loads are generally trending moderately in the negative direction in winter and moderately in the positive direction in the summer. Since the winter load is significantly larger than the summer load, the overall trend for the period of the forecast is in the negative direction.

We wish to point out that our demand forecast excludes the contribution of any distribution system connected distributed generation. As you are aware, we presently have a significant solar contribution of approximately 62MW to our distribution system. This generation results in near zero or net export conditions during their peak producing summer months when our system is near its minimum load. The generation was connected as part of the OPA RESOP and FIT programs. Because of its significant degree of penetration, distributed generation may be material to the RIP process.

Furthermore, with respect to distributed generation, there continues to be a strong interest in developing green energy in our community and this is being pursued on a number of municipal and private interests. We expect this will continue and may lead to requests to connect additional significant projects in the near to long term future (3 to 10 years).

One final topic we wish to draw your attention to is the age of our four 115kV lines and the two 115kV/34.5kV stations that connect us with GLPT. This infrastructure was installed about 40 years ago in the 1970s. Although we believe the transmission lines have several decades of serviceable life left, it is our belief that the two stations will require a major upgrade within 5 to 15 years. Although we currently do not have a specific asset management plan in place for these assets, we do intend to develop one in 2014.

We trust this submission meets all of the current requirements of the RIP process and look forward to working with you on this matter. Should you require anything further please direct your inquiries to my attention.

Best Regards,

Rob Harten, P. Eng.
Manager of Engineering

File: 0509.6 OEB RIP_letter_to_GLPTD_2014-09-23.doc

Load Forecast Template

Customer Name: Sault Ste Marie PUC
Region Name: East Lake Superior

Notes:

1	Enter data for the transformer stations supplying your LDC and if there is a missing transformer station please add it to the current list
2	For LDCs directly connected to the transmission facilities, load forecasts should factor in the load forecasts of any embedded distributor. Include a list of all embedded distributors
3	For LDCs that are embedded in another distributor's system, DO NOT include your embedded load in forecasts submitted to the transmitter; instead, submit the embedded load forecasts to the host distributor for inclusion in their submission to the transmitter.
4	Provide coincident load forecast aggregated for all your feeders at the Station Level.
5	For Historical Data, LDCs are to provide the Net Load, i.e. Gross Peak Load minus any EXISTING Conservation & Demand Management (CDM) and Distributed Generation (DG), available during the time of peak demand.
6	For Forecasted Data, LDCs are to only provide the Gross Peak Load (which is the Forecasted Load from their Historical Net Load). OPA will provide Forecasted DG and CDM.
7	Provide load forecast in MWs and include power factor assumptions, if any.
8	List all assumptions made in preparing this load forecast.

		Peak Load (Net = Gross - DG - CDM)													
TS Name or DP	**Customer Data (MW)**	**Historical Data (MW)**			**Near Term Forecast (MW)**					**Medium Term Forecast (MW)**					**Power Factor**
		2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	
Tarentorus T.S. (TS2)	Gross Peak Load				37.1	37.1	37.1	37.0	37.0	37.0	37.0	37.0	36.9	36.9	0.967
GL1TA(non-coincident)	Net Load	21.1	37.1	0.1											
Tarentorus T.S. (TS2)	Gross Peak Load				51.7	51.6	51.6	51.6	51.5	51.5	51.5	51.5	52.1	51.4	0.967
GL2TA(non-coincident)	Net Load	48.1	24.0	51.7											
St. Mary's T.S. (TS1)	Gross Peak Load				52.4	52.3	52.3	52.3	52.2	52.2	52.2	52.2	52.1	52.1	0.967
GL1SM(non-coincident)	Net Load	41.3	34.9	52.4											
St. Mary's T.S. (TS1)	Gross Peak Load				60.5	60.5	60.5	60.4	60.4	60.4	60.3	60.3	60.3	60.2	0.967
GL2SM(non-coincident)	Net Load	39.3	36.2	35.1											
Total PUC	Gross Peak Load				139.3	139.2	139.2	139.1	139.1	139.0	139.0	138.9	138.8	138.8	0.967
(coincident peak)	Net Load	149.9	132.2	139.2											0.967

LDC Assumptions:

1) Assumed that Generation and CDM are accounted for in Net Load Forecast of the Historical Data.
2) Assumed that the full benefit of Generation and CDM are active during peak loads.
3) Peeks for individual circuits are NOT coincident peaks with system peak; they are case by case worst case peaks for the individual feeders in a given year based on the maximum feeder load for the period 2011-2013
4) As it is unknown to PUC as to how power factor relates to load, a power factor based on the average historical value has been assumed for the forecast

From: Brooke Suurna
To: Rob Harten; Claudio Stefano
Subject: 2011-2013 CDM Demand Savings
Date: Friday, September 19, 2014 10:50:42 AM
Attachments: image003.jpg

I was originally going to provide quarterly data for 2011-2013 however upon review of the data I don't believe the quarterly numbers from the OPA are accurate because they were changed as subsequent quarterly reports were released. The only numbers I am 100% confident in are the final annual results released by the OPA.

Year	Demand Savings (MW)
2011	0.7
2012	0.8
2013	1.1

Please let me know if you require anything further

Brooke Suurna, P.Eng
Conservation & Demand Management Officer
PUC Services Inc.
500 Second Line E., P.O. Box 9000
Sault Ste Marie, ON P6A 6P2
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Email: brooke.suurna@ssmpuc.com

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Forecast Calculations

System Total Peak Load

	Year	Net Peak Load	Gross Peak Load
Actual	2007 Actual	139,708	139,708
	2008 Actual	139,124	139,124
	2009 Actual	147,108	147,108
	2010 Actual	141,244	141,244
	2011 Actual	149,857	149,952
	2012 Actual	132,164	132,154
	2013 Actual	139,248	139,361
Projected	2014	139,171	139,303
	2015	139,095	139,245
	2016	139,018	139,187
	2017	138,942	139,129
	2018	138,865	139,072
	2019	138,789	139,014
	2020	138,713	138,956
	2021	138,637	138,899
	2022	138,560	138,841
	2023	138,484	138,784

Feeder Peak Loads (Non-Coincident Net)

	Year	Net Peak Load (MW) GL1TA	Net Peak Load (MW) GL2TA	Net Peak Load (MW) GL1SM	Net Peak Load (MW) GL2SM
Actual	Maximum of Calendar Years 2011 - 2013	37.12	51.68	52.39	60.57
Projected	2014	37.10	51.65	52.36	60.54
	2015	37.08	51.62	52.34	60.50
	2016	37.06	51.60	52.31	60.47
	2017	37.04	51.57	52.28	60.44
	2018	37.02	51.54	52.25	60.40
	2019	37.00	51.51	52.22	60.37
	2020	36.98	51.48	52.19	60.34
	2021	36.96	51.45	52.16	60.31
	2022	36.94	51.43	52.13	60.27
	2023	36.92	51.40	52.11	60.24

Growth Rate

Year	Rate (Net)	Rate (Gross)
2007 - 2008	0.9958	0.9958
2008 - 2009	1.0574	1.0574
2009 - 2010	0.9601	0.9601
2010 - 2011	1.0610	1.0617
2011 - 2012	0.8819	0.8813
2012 - 2013	1.0536	1.0545
Geomean	0.9995	0.9996

Notes: growth rate was used to calculate project growth

Total System Electric Loading History

	Energy 2001 kWh	Energy 2002 kWh	Energy 2003 kWh	Energy 2004 kWh	Energy 2005 kWh	Energy 2006 kWh	Energy 2007 kWh	Energy 2008 kWh	Energy 2009 kWh
YTD Totals	718,680,760	744,156,060	755,126,020	757,685,852	749,219,032	728,093,333	738,093,576	740,966,488	732,869,986
January	78,253,278	75,783,700	85,049,952	89,226,840	88,287,600	76,234,176	78,292,016	79,006,867	85,774,977
February	71,056,718	69,010,564	76,788,076	73,066,340	71,065,788	71,202,696	75,583,244	75,126,906	71,566,146
March	70,086,644	73,544,560	75,545,096	71,196,888	73,186,104	70,367,240	71,668,468	74,573,962	72,767,317
April	58,715,640	61,508,916	63,274,204	61,357,220	56,446,820	56,652,640	60,506,916	58,751,936	59,966,274
May	50,799,464	56,801,704	52,784,032	55,571,152	53,664,344	52,446,572	51,273,936	53,931,566	52,676,063
June	49,362,308	50,055,824	49,325,848	49,366,380	51,111,168	49,917,449	50,644,216	48,466,639	49,196,439
July	49,714,844	53,526,780	51,148,508	51,210,208	53,387,012	53,606,640	51,622,068	50,725,083	48,238,905
August	51,535,500	51,335,848	50,113,412	50,192,756	52,102,684	51,038,392	51,764,316	50,225,177	49,652,791
September	48,974,448	50,111,652	49,728,476	50,272,804	49,504,120	49,455,772	48,836,864	48,690,797	48,812,970
October	56,653,116	57,639,776	58,883,124	57,641,764	55,381,484	58,920,568	54,192,940	56,073,866	57,724,020
November	61,414,444	67,404,840	66,040,876	64,887,008	65,851,664	63,979,576	65,729,492	63,785,625	59,532,749
December	72,114,356	77,431,896	76,444,416	83,696,492	79,230,244	74,271,612	77,979,100	81,608,064	76,961,335
3-month total	150,612,652	154,918,452	150,587,768	150,769,344	156,600,864	154,562,481	154,030,600	149,416,898	147,088,135
Summer Average	50,204,217	51,639,484	50,195,923	50,256,448	52,200,288	51,520,827	51,343,533	49,805,633	49,029,378

	2010			2011			2012			2013			2014		
	Wholesale Meter Energy 2010 kWh	**Distributed Gen Energy 2010 kWh**	**Total System Energy 2010 kWh**	**Wholesale Meter Energy 2011 kWh**	**Distributed Gen Energy 2011 kWh**	**Total System Energy 2011 kWh**	**Wholesale Meter Energy 2012 kWh**	**Distributed Gen Energy 2012 kWh**	**Total System Energy 2012 kWh**	**Wholesale Meter Energy 2013 kWh**	**Distributed Gen Energy 2013 kWh**	**Total System Energy 2013 kWh**	**Wholesale Meter Energy 2014 kWh**	**Distributed Gen Energy 2014 kWh**	**Total System Energy 2014 kWh**
YTD Totals	710,857,306	2,305,988	713,163,294	693,045,100	36,883,588	729,928,688	635,223,994	78,072,955	713,296,949	659,215,628	70,879,868	730,095,496	359,501,319	35,392,364	394,893,683
January	79,854,697	0	79,854,697	82,648,728	685,685	83,334,413	75,554,837	830,876	76,385,713	76,231,996	1,215,534	77,447,531	83,292,308	784,023	84,076,331
February	68,437,902	0	68,437,902	70,439,804	1,633,071	72,072,875	64,040,984	3,779,719	67,820,704	68,219,789	1,575,061	69,794,850	70,305,579	2,977,471	73,283,050
March	63,113,132	0	63,113,132	68,440,898	3,244,798	71,685,695	58,334,633	5,542,828	63,877,461	62,222,455	7,041,704	69,264,159	69,150,658	6,785,778	75,936,435
April	53,088,771	0	53,088,771	57,001,677	3,031,773	60,033,450	47,033,398	9,901,424	56,934,822	56,115,257	6,375,267	62,490,524	54,009,639	6,936,289	60,945,928
May	51,130,272	0	51,130,272	48,309,149	3,345,715	51,654,863	41,538,463	10,563,057	52,101,520	42,336,726	8,924,016	51,260,742	45,055,529	8,072,055	53,127,584
June	47,896,130	0	47,896,130	44,474,216	3,325,220	47,799,435	40,321,370	10,262,554	50,583,924	38,741,499	9,504,552	48,246,051	37,687,605	9,836,750	47,524,355
July	53,062,397	0	53,062,397	49,476,613	4,002,802	53,479,415	44,339,537	11,305,974	55,645,511	42,744,917	9,501,815	52,246,732			0
August	53,165,646	0	53,165,646	48,089,241	4,651,619	52,740,860	41,430,538	9,785,385	51,215,923	40,863,333	10,239,998	51,103,331			0
September	48,475,869	0	48,475,869	44,365,173	6,150,436	50,515,609	40,740,588	7,746,529	48,487,116	39,805,113	8,252,743	48,057,856			0
October	53,271,933	806,084	54,078,017	50,577,506	2,624,178	53,201,684	50,702,525	4,734,240	55,436,765	49,039,469	5,154,603	54,194,072			0
November	61,524,030	1,105,052	62,629,082	58,264,120	2,342,368	60,606,488	59,933,496	2,488,914	62,422,410	62,214,471	2,461,092	64,675,563			0
December	77,836,527	394,852	78,231,379	70,957,977	1,845,923	72,803,900	71,253,625	1,131,456	72,385,081	80,680,603	633,483	81,314,086			0
3-month total	154,124,173	0	154,124,173	142,040,069	11,979,641	154,019,710	126,091,445	31,353,913	157,445,358	122,349,749	29,246,365	151,596,114	37,687,605	9,836,750	47,524,355
Summer Average	51,374,724	0	51,374,724	47,346,690	3,993,214	51,339,903	42,030,482	10,451,304	52,481,786	40,783,250	9,748,788	50,532,038	12,562,535	3,278,917	15,841,452

	Demand 2001 kW	Demand 2002 kW	Demand 2003 kW	Demand 2004 kW	Demand 2005 kW	Demand 2006 kW	Demand 2007 kW	Demand 2008 kW	Demand 2009 kW
January	136,152	133,624	147,064	150,828	156,336	137,316	137,364	139,124	147,108
February	128,524	132,204	142,840	133,168	132,028	131,504	139,708	137,099	140,994
March	122,084	129,004	143,188	121,748	132,728	121,328	138,956	126,361	134,710
April	104,040	110,624	118,652	108,156	99,876	110,744	120,464	113,370	109,073
May	88,452	102,020	89,152	103,988	98,032	95,184	90,156	93,108	91,475
June	91,560	91,424	97,240	90,496	96,532	88,948	100,876	86,634	97,507
July	95,032	98,244	91,376	90,784	100,440	99,704	100,184	91,419	82,098
August	96,272	91,912	89,224	89,708	98,928	94,792	101,464	92,154	92,161
September	94,488	97,104	91,968	92,732	96,484	87,132	94,760	95,412	90,184
October	101,716	106,588	107,616	100,520	95,520	104,856	93,000	101,744	102,250
November	125,460	126,200	120,924	120,900	136,364	119,060	133,912	119,819	111,244
December	130,692	137,444	134,140	159,136	141,964	134,212	135,708	144,796	134,470
System Winter Peak	147,690	133,624	147,064	150,828	159,136	141,964	139,708	139,124	147,108
Peak Month	December' 2000	January' 2002	January' 2003	January' 2004	December' 2004	December' 2005	February' 2007	January'2008	January'2009

	Wholesale Meter Demand 2010 kW	Adjusted for DG Demand 2010 kW		Wholesale Meter Demand 2011 kW	Adjusted for DG Demand 2011 kW		Wholesale Meter Demand 2012 kW	Adjusted for DG Demand 2012 kW		Wholesale Meter Demand 2013 kW	Adjusted for DG Demand 2013 kW		Wholesale Meter Demand 2014 kW	Adjusted for DG Demand 2014 kW	
January	141,244			149,857	149,857		132,090	132,154		138,936	138,936		143,061	143,172	
February	129,450			136,294	136,294		115,178	126,117		129,404	129,440		139,986	140,075	
March	109,694			124,344	124,344		117,881	118,115		115,636	115,710		135,918	135,983	
April	97,996			104,965	107,493		49,908	98,975	49.6%	111,773	111,959	0.2%	106,629	106,738	0.1%
May	97,193			90,361	92,646		36,736	94,353	61.1%	90,856	93,804		88,990	89,101	
June	87,013			94,306	94,306		52,482	104,308	49.7%	59,677	95,568	38%	59,003	87,494	33%
July	96,868			95,135	100,702		50,311	104,552		78,335	104,736				
August	101,492			88,991	97,338		69,686	92,694		64,298	99,844				
September	93,047			89,277	97,824		66,742	92,013		89,768	90,949				
October	96,934	96,934		94,283	94,370		102,667	102,702		98,465	98,465				
November	123,865	123,865		112,491	112,491		118,381	118,527		124,726	124,838				
December	141,147	141,147		128,372	128,372		122,761	122,935		139,248	139,361				
System Winter Peak	141,244				149,857			132,154							
Peak Month	January'2010				January'2011			January'2012							

Note: Winter is defined as December of the previous year to February of the current year

	LF 2001	LF 2002	LF 2003	LF 2004	LF 2005	LF 2006	LF 2007	LF 2008	LF 2009	LF 2010	LF 2011
January	77.3%	76.2%	77.7%	79.5%	75.9%	74.6%	76.6%	76.3%	78.4%	76.0%	74.1%
February	82.3%	77.7%	80.0%	78.8%	80.1%	80.6%	80.5%	78.7%	72.9%	76.0%	74.3%
March	77.2%	76.6%	70.9%	78.6%	74.1%	78.0%	69.3%	79.3%	72.6%	77.3%	74.0%
April	78.4%	77.2%	74.1%	78.8%	78.5%	71.1%	69.8%	72.0%	76.4%	75.2%	75.4%
May	77.2%	74.8%	79.6%	71.8%	73.6%	74.1%	76.4%	77.9%	77.4%	70.7%	71.9%
June	74.9%	76.0%	70.5%	75.8%	73.5%	77.9%	69.7%	77.7%	70.1%	76.5%	65.5%
July	70.3%	73.2%	75.2%	75.8%	71.4%	72.3%	69.3%	74.6%	79.0%	73.6%	69.9%
August	72.0%	75.1%	75.5%	75.2%	70.8%	72.4%	68.6%	73.3%	72.4%	70.4%	72.6%
September	72.0%	71.7%	75.1%	75.3%	71.3%	78.8%	71.6%	70.9%	75.2%	72.4%	69.0%
October	74.9%	72.7%	73.5%	77.1%	77.9%	75.5%	78.3%	74.1%	75.9%	73.9%	72.1%
November	68.0%	74.2%	75.9%	74.5%	67.1%	74.6%	68.2%	73.9%	74.3%	69.0%	71.9%
December	74.2%	75.7%	76.6%	70.7%	75.0%	74.4%	77.2%	75.8%	76.9%	74.1%	74.3%

Total System Electric Loading

	2011			2012			2013		
	Wholesale Meter Energy 2011 kWh	Distributed Gen Energy 2011 kWh	Total System Energy 2011 kWh	Wholesale Meter Energy 2012 kWh	Distributed Gen Energy 2012 kWh	Total System Energy 2012 kWh	Wholesale Meter Energy 2013 kWh	Distributed Gen Energy 2013 kWh	Total System Energy 2013 kWh
YTD Totals	693,045,100	36,883,588	729,928,688	635,223,994	78,072,955	713,296,949	659,215,628	70,879,868	730,095,496
January	82,648,728	685,685	83,334,413	75,554,837	830,876	76,385,713	76,231,996	1,215,534	77,447,531
February	70,439,804	1,633,071	72,072,875	64,040,984	3,779,719	67,820,704	68,219,789	1,575,061	69,794,850
March	68,440,898	3,244,798	71,685,695	58,334,633	5,542,828	63,877,461	62,222,455	7,041,704	69,264,159
April	57,001,677	3,031,773	60,033,450	47,033,398	9,901,424	56,934,822	56,115,257	6,375,267	62,490,524
May	48,309,149	3,345,715	51,654,863	41,538,463	10,563,057	52,101,520	42,336,726	8,924,016	51,260,742
June	44,474,216	3,325,220	47,799,435	40,321,370	10,262,554	50,583,924	38,741,499	9,504,552	48,246,051
July	49,476,613	4,002,802	53,479,415	44,339,537	11,305,974	55,645,511	42,744,917	9,501,815	52,246,732
August	48,089,241	4,651,619	52,740,860	41,430,538	9,785,385	51,215,923	40,863,333	10,239,998	51,103,331
September	44,365,173	6,150,436	50,515,609	40,740,588	7,746,529	48,487,116	39,805,113	8,252,743	48,057,856
October	50,577,506	2,624,178	53,201,684	50,702,525	4,734,240	55,436,765	49,039,469	5,154,603	54,194,072
November	58,264,120	2,342,368	60,606,488	59,933,496	2,488,914	62,422,410	62,214,471	2,461,092	64,675,563
December	70,957,977	1,845,923	72,803,900	71,253,625	1,131,456	72,385,081	80,680,603	633,483	81,314,086
3-month total	142,040,069	11,979,641	154,019,710	126,091,445	31,353,913	157,445,358	122,349,749	29,246,365	151,596,114
Summer Average	47,346,690	3,993,214	51,339,903	42,030,482	10,451,304	52,481,786	40,783,250	9,748,788	50,532,038

	Wholesale Meter Demand 2011 kW	Adjusted for DG Demand 2011 kW		Wholesale Meter Demand 2012 kW	Adjusted for DG Demand 2012 kW		Wholesale Meter Demand 2013 kW	Adjusted for DG Demand 2013 kW	
January	149,857	149,857		132,090	132,154		138,936	138,936	
February	136,294	136,294		115,178	126,117		129,404	129,440	
March	124,344	124,344		117,881	118,115		115,636	115,710	
April	104,965	107,493		49,908	98,975	49.6%	111,773	111,959	0.2%
May	90,361	92,646		36,736	94,353	61.1%	90,856	93,804	
June	94,306	94,306		52,482	104,308	49.7%	59,677	95,568	38%
July	95,135	100,702		50,311	104,552		78,335	104,736	
August	88,991	97,338		69,686	92,694		64,298	99,844	
September	89,277	97,824		66,742	92,013		89,768	90,949	
October	94,283	94,370		102,667	102,702		98,465	98,465	
November	112,491	112,491		118,381	118,527		124,726	124,838	
December	128,372	128,372		122,761	122,935		139,248	139,361	

System Winter Peak
Peak Month

2011	Date	Interval	Gross Load	Power factor	GL1TA	GL2TA	GL1SM	GL2SM	DG Contribution	GLPT Contribution
January	23-Jan-11	19	149,952	0.966	21079.1	48127.5	41337.4	39313.2	95	149857.2
February	9-Feb-11	19	136,345	0.996	15227.3	43511.1	38978.6	38577.2	51	136294.2
March	2-Mar-11	20	124,406	0.968	15474	39853.4	33384.8	35631.3	63	124343.5
April	17-Apr-11	16	107,694	0.968	13923.5	31958.1	31615.5	27467.5	2,730	104964.6
May	3-May-11	17	92,850	0.966	35558.2	26713.2	0	27540	3,039	89811.4
June	7-Jun-11	21	94,493	0.938	33735.2	0	0	60571.1	187	94306.3
July	18-Jul-11	17	100,702	0.945	23159.7	18832.3	0	47599.5	11,111	89591.5
August	5-Aug-11	16	97,338	0.899	0	15454.6	16255.1	47806.3	17,822	79516
September	12-Sep-11	16	97,824	0.908	0	18184.1	25314.4	26833.1	27,492	70331.6
October	17-Oct-11	19	94,480	0.965	10996.5	32506.1	25727	25053	197	94282.6
November	21-Nov-11	18	112,692	0.973	23848.1	35231.3	19989	33422.9	201	112491.3
December	28-Dec-11	19	128,565	0.973	24425.1	40660.8	23866.2	39420.3	192	128372.4

2012	Date	Interval	Gross Load	Power factor	GL1TA	GL2TA	GL1SM	GL2SM	DG Contribution	GLPT Contribution
January	19-Jan-12	20	132,154	0.968	37119.5	23950.6	34856.7	36237.6	(10)	132164.4
February	11-Feb-12	11	126,117	0.969	9823.6	34053.6	39068.5	32232.5	10,939	115178.2
March	5-Mar-12	9	118,115	0.973	12352	34383.2	40389.2	30756.8	234	117881.2
April	17-Apr-12	12	98,975	0.877	0	7267.6	17853	24787.8	49,066	49908.4
May	10-May-12	14	94,353	0.571	0	0	5547.3	31188.5	57,617	36735.8
June	11-Jun-12	13	104,308	0.76	0	13435.1	11544.8	27501.8	51,826	52481.7
July	4-Jul-12	13	104,552	0.757	0	7427	13106.8	29777.6	54,241	50311.4
August	30-Aug-12	16	92,694	0.899	3566.8	19500.8	6814.5	40207.8	22,604	70089.9
September	4-Sep-12	17	92,013	0.902	3146.9	28714.4	34798.8	81.5	25,271	66741.6
October	30-Oct-12	19	102,702	0.969	10245.5	29446.6	35513.3	27461.1	35	102666.5
November	30-Nov-12	18	118,527	0.969	20618.6	37103.4	31972.7	28686.5	145	118381.2
December	11-Dec-12	18	122,935	0.97	21169.4	38407	33611.1	29573.1	174	122760.6

2013	Date	Interval	Gross Load	Power factor	GL1TA	GL2TA	GL1SM	GL2SM	DG Contribution	GLPT Contribution
January	22-Jan-13	20	138,936	0.971	13846.8	41386.6	48307	35395.9	-	138936.3
February	6-Feb-13	20	129,440	0.972	13212.6	41578.7	36942.7	37669.7	37	129403.7
March	3-Mar-13	20	115,710	0.97	9391.7	39529.5	36944.1	29770.2	75	115635.5
April	2-Apr-13	20	111,959	0.973	11613	29754.6	38519.7	31885.6	186	111772.9
May	12-May-13	11	93,804	0.971	24895	7788.3	30606.5	27566.1	2,948	90855.9
June	26-Jun-13	16	95,568	0.865	43	21043.1	19149.9	20658.4	34,673	60894.4
July	17-Jul-13	16	105,070	0.89	0	23950.5	22783.8	31601	26,735	78335.3
August	29-Aug-13	16	100,086	0.869	1064.9	19540.3	24308.3	19729.4	35,443	64642.9
September	10-Sep-13	17	91,012	0.945	19524.1	18962.7	31934.2	19346.9	1,244	89767.9
October	29-Oct-13	19	98,633	0.998	71.8	35553.7	37925.5	24913.7	168	98464.7
November	24-Nov-13	18	124,838	0.972	13351.1	35814.5	44595.7	30964.4	112	124725.7
December	14-Dec-13	18	139,361	0.967	69.7	51681.6	52393.5	35103	113	139247.8

	GL1TA	GL2TA	GL1SM	GL2SM	DG Contribution	GLPT Contribution
Maximum Value over three year period 2011-2013	37119.5	51681.6	52393.5	60571.1	57616.74	149857.2

Appendix F

OEB Score Card Performance Measures

Scorecard - PUC Distribution Inc.

9/24/2014

									Target	
Performance Outcomes	**Performance Categories**	**Measures**	**2009**	**2010**	**2011**	**2012**	**2013**	**Trend**	**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	98.20%	96.70%	97.80%	95.80%	96.50%	↓	90.00%	
		Scheduled Appointments Met On Time	96.10%	92.40%	97.20%	98.40%	97.10%	↑	90.00%	
		Telephone Calls Answered On Time	65.10%	70.10%	76.70%	74.60%	80.90%	↑	65.00%	
	Customer Satisfaction	First Contact Resolution								
		Billing Accuracy								
		Customer Satisfaction Survey Results								
Operational Effectiveness **Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.**	**Safety**	Public Safety [measure to be determined]								
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted	2.14	2.11	2.92	1.65	2.48	↑		at least within 1.65 - 2.92
		Average Number of Times that Power to a Customer is Interrupted	2.97	2.83	3.61	2.17	2.67	↓		at least within 2.17 - 3.61
	Asset Management	Distribution System Plan Implementation Progress								
	Cost Control	Efficiency Assessment				3	4			
		Total Cost per Customer [1]	$456	$485	$513	$615	$687			
		Total Cost per Km of Line [1]	$20,445	$21,729	$22,981	$27,523	$30,950			
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 Annual Peak Demand Savings (Percent of target achieved) [2]			12.00%	14.00%	19.20%			5.58MW
		Net Cumulative Energy Savings (Percent of target achieved)			35.00%	61.00%	87.20%			30.83GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		100.00%	66.67%					
		New Micro-embedded Generation Facilities Connected On Time					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)	1.38	1.39	1.43	1.19	1.06			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	1.52	1.53	1.44	2.01	1.99			
		Profitability: Regulatory Return on Equity Deemed (included in rates)			8.57%	8.57%	8.98%			
		Achieved			8.16%	4.99%	7.00%			

Legend:

- ↑ up
- ↓ down
- → flat
- 🟢 target met
- 🔴 target not met

Notes:

1. These figures were generated by the Board based on the total cost benchmarking analysis conducted by Pacific Economics Group Research, LLC and based on the distributor's annual reported information.
2. The Conservation & Demand Management net annual peak demand savings do not include any persisting peak demand savings from the previous years.

Scorecard - PUC Distribution Inc.

9/28/2015

Performance Outcomes	Performance Categories	Measures		2010	2011	2012	2013	2014	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		96.70%	97.80%	95.80%	96.50%	93.00%	⬇ 🟢	90.00%	
		Scheduled Appointments Met On Time		92.40%	97.20%	98.40%	97.10%	95.40%	⬆ 🟢	90.00%	
		Telephone Calls Answered On Time		70.10%	76.70%	74.60%	80.90%	81.90%	⬆ 🟢	65.00%	
	Customer Satisfaction	First Contact Resolution						99.89%			
		Billing Accuracy						99.83%	➡ 🟢	98.00%	
		Customer Satisfaction Survey Results						In progess			
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 [measure to be determined]									
		Level of Compliance with Ontario Regulation 22/04		NI	NI	NI	C	C	⬆ 🟢		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	3	1	3	⬆ 🔴		1
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.407	0.135	0.405	⬆ 🔴		0.132
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted		2.11	2.92	1.65	2.48	1.19	⬇ 🟢		at least within 1.65 - 2.92
		Average Number of Times that Power to a Customer is Interrupted		2.83	3.61	2.17	2.67	1.21	⬇ 🟢		at least within 2.17 - 3.61
	Asset Management	Distribution System Plan Implementation Progress						In progress			
	Cost Control	Efficiency Assessment				3	4	4			
		Total Cost per Customer [1]		$485	$513	$615	$687	$664			
		Total Cost per Km of Line [1]		$21,729	$22,981	$27,523	$30,950	$29,886			
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 Annual Peak Demand Savings (Percent of target achieved) [2]			11.19%	24.67%	43.55%	59.52%	🔴		5.58MW
		Net Cumulative Energy Savings (Percent of target achieved)			35.22%	60.88%	87.17%	99.06%	🔴		30.83GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		100.00%	66.67%						
		New Micro-embedded Generation Facilities Connected On Time					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)		1.39	1.43	1.19	1.06	1.68			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.53	1.44	2.01	1.99	2.42			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)		8.57%	8.57%	8.98%	8.98%			
			Achieved		8.16%	4.99%	7.00%	5.47%			

Legend:

⬆ up	⬇ down	➡ flat
🟢 target met	🔴 target not met	

Notes:
1. These figures were generated by the Board based on the total cost benchmarking analysis conducted by Pacific Economics Group Research, LLC and based on the distributor's annual reported information.
2. The Conservation & Demand Management net annual peak demand savings include any persisting peak demand savings from the previous years.

Appendix A – 2014 Scorecard Management Discussion and Analysis ("2014 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 2014 Scorecard MD&A:

http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf

Scorecard MD&A - General Overview

For the year 2014, PUC Distribution exceeded prescribed targets for most scorecard measures. In particular, system reliability performance for the year 2014 was the best achieved since 1999. This notable improvement in reliability is primarily the result of ongoing efforts related to replacing aging or defective infrastructure and improved vegetation management.

For 2014, average interruption duration (SAIDI) decreased 52% compared to 2013, while average interruption frequency (SAIFI) decreased 55%. Moving forward, PUC Distribution plans to continue efforts aimed at improving reliability for its customers thereby delivering greater value for the service provided to them.

Service Quality

- **New Residential/Small Business Services Connected on Time**

  In 2014, PUC Distribution connected 213 eligible low-voltage residential and small business customers (connections under 750 volts) to its system, 93% of which were connected within the five-day timeline prescribed by the Ontario Energy Board (OEB). This is a 3.5% decrease from the previous year but still above the OEB-mandated target of 90%. PUC Distribution is undergoing process reviews for the purpose of identifying any potential areas of improvement and to continue to ensure that the New Service performance measures are exceeded.

- **Scheduled Appointments Met On Time**

  In 2014, PUC Distribution scheduled 1,466 appointments with customers to complete customer requested work (e.g. meter re-reads, reconnections, meter locates, etc.). Although a slight decrease from 2013, PUC Distribution met 95.4% of these appointments on time, which exceeds the OEB-mandated target of 90%.

- **Telephone Calls Answered On Time**

In 2014, PUC Distribution's Customer Care Department received 39,681 calls from its customers – that's over 159 calls per working day. Of those calls, a Customer Care Representative answered the call in 30 seconds or less, 81.90% of the time. This result significantly exceeds the OEB-mandated 65% target for timely call response. The 2014 result amounts to a 1% improvement over 2013, driven primarily by a reduction in the number of calls, due primarily to fewer outages in 2014. Also, the reduction in call volume can, in part, be attributed to the introduction of automated emergency messaging employed during large scale power outages. Additionally, the shift towards email as the communication medium of choice for customers has also contributed to the reduction.

Customer Satisfaction

Specific customer satisfaction measurements have not been previously defined across the industry. The OEB has instructed all electricity distributors to review and develop measurements in these areas and begin tracking by July 1, 2014 so that information can be reported in 2015. The OEB plans to review information provided by electricity distributors over the next few years and implement a commonly defined measure for these areas in the future. As a result, each distributor may have different measurements of performance until such time as the OEB provides specific direction regarding a commonly defined measure.

- **First Contact Resolution**

  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 Distribution's First Contact Resolution was measured by tracking the number of electric related calls which were escalated to a Supervisor/Manager and a Senior Customer Care Representative. This was done by creating two specific call types in our Customer Information System (CIS) which could 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 CIS was queried based on the associated call types to arrive at the number of customer calls handled by the Customer Care Team.

  To determine the number of repeat calls for the same issue, a review of the escalated calls was conducted on the premise that if the call reached the Senior Customer Care level the concern would not have been satisfactorily resolved at the time of first contact.

- **Billing Accuracy**

  Until July 2014 a specific measurement of billing accuracy had not been previously defined across the industry. After consultation with some electricity distributors, the OEB has prescribed a measurement of billing accuracy which must be used by all distributors effective October 1, 2014. For the period from October 1, 2014 – December 31, 2014 PUC Distribution issued more than 100,000 bills and achieved a billing accuracy of 99.83%. This compares favorably to the prescribed OEB target of 98%.

PUC Distribution continues to monitor its billing accuracy results and processes to identify opportunities for improvement.

- **Customer Satisfaction Survey Results**

  The OEB introduced the Customer Satisfaction Survey Results measure beginning in 2013. At a minimum, electricity distributors are required to measure and report a customer satisfaction result at least every other year. At this time the OEB is allowing distributors discretion as to how they implement this measure.

  PUC engaged a third party to conduct the customer satisfaction survey. The survey was conducted in April 2015 and completed in June 2015, therefore, survey results along with the mangement discussion will published on the 2015 Scorecard.

Safety

- **Public Safety**

  The OEB introduced the Safety Measure in 2015. This measure looks at safety from a customer's point of view as safety of the distribution system is a high priority. The Safety measure is generated by the Electrical Safety Authority (ESA) and includes three components: Public Awareness of Electrical Safety, Compliance with Ontario Regulation 22/04 and the Serious Electrical Incident Index.

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

    This Component of the public safety measure does not have performance data for the 2014 scorecard as the public awareness of electrical safety survey was not required to be conducted in the subject year. 2016 will be the first year that data for this measure will be reported on the scorecard for the 2015 results.

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

  Component B is comprised of: the External Audit, the Declaration of Compliance, Due Diligence Inspections, Public Safety Concerns and Compliance Investigations. All these elements are evaluated as a whole and determine the status of compliance. Over the past two years, PUC Distribution was found to be compliant with Ontario Regulation 22/04 (Electrical Distribution Safety). This was achieved by our strong commitment to safety and adherence to company policies and procedures. 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 C – Serious Electrical Incident Index**

  PUC Distribution reported three (3) serious electrical incidents involving members of the public in 2014. There were no injuries associated with these incidents. A detailed analysis of the data and root cause evidence has helped steer PUC Distribution's efforts to increase public awareness in an effort to eliminate future incidents. PUC Distribution offers electrical safety awareness outreach via newspaper and radio ads, presentations to elementary school students, and detailed hazard awareness presentations to contractors.

System Reliability

- **Average Number of Hours that Power to a Customer is Interrupted**

  Average duration of outages for the year 2014 demonstrated a marked improvement compared to 2013. In fact, 2014 system reliability was the best achieved since 1999. The notable improvement in reliability is due primarily to ongoing efforts related to replacing aging or defective infrastructure and improved vegetation management. Continued improvement is anticipated moving forward.

  Average interruption duration for 2014 decreased 52% compared to 2013.

- **Average Number of Times that Power to a Customer is Interrupted**

  Average frequency of outages for the year 2014 also demonstrated a marked improvement compared to 2013. Average interruption frequency for 2014 decreased 55% compared to 2013.

Asset Management

- **Distribution System Plan Implementation Progress**

  All distributors are required to file a Distribution System Plan (DSP) when filing a cost of service application for the rebasing of their rates. Accordingly, PUC Distribution plans to file an application with the OEB for a full review of its rates effective May 1, 2017, which will include a complete DSP.

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.

Group	Demarcation Points for Relative Cost Performance	% of Ontario LDCs in Group
1	Actual costs are 25% or more below predicted costs	8
2	Actual costs are 10% to 25% below predicted costs	20
3	Actual costs are within +/-10% of predicted costs	47
4	Actual costs are 10% to 25% above predicted costs	18
5	Actual costs are 25% or more above predicted costs	7

In 2014, as in 2013, PUC Distribution was placed in Group 4, where a Group 4 distributor is defined as having actual costs between 10% and 25% of predicted costs under the PEG model. Group 3 is considered "average efficiency".

PUC Distribution's efficiency performance improved from 22.7% in 2013 to 14.6% in 2014.

- **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 2014 is $664/customer which is a 3.4 % decrease over 2013.

  Overall, the company’s Total Cost per Customer has increased on average by 7.3% per annum over the period 2010 through 2014. Similar to most distributors in the province, PUC Distribution has experienced increases in its total costs required to deliver quality and reliable services to customers. Province-wide programs such as Time of Use pricing, growth in wage and benefits costs for employees, as well as investments in new information systems technology and the renewal of the distribution system, have all contributed to increased operating and capital costs.

  PUC Distribution will continue to replace 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 2017 rate application to be filed in 2016. 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 2015 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 2014 rate is $29,886 per Km of line, a 3.4% decrease over 2013.

  PUC Distribution has experienced 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 since 2010 with the increase in capital and operating costs.

Conservation & Demand Management

- **Net Annual Peak Demand Savings (Percent of target achieved)**

  PUC Distribution achieved 59.52% of its 2011-2014 Peak Demand target of 5.58 MW. It was a challenge to meet the peak demand target due to the fact PUC Distribution is a winter peaking utility. PUC Distribution was pleased with its efforts as peak demand savings results aligned fairly well with the provincial average.

- **Net Cumulative Energy Savings (Percent of target achieved)**

  PUC Distribution achieved 99.06% of its 2011-2014 net cumulative energy savings target of 30.83 GWh. Much of this success can be attributed to the successful promotion of energy efficiency programs and strong participation by commercial customers in the Retrofit and Small Business Lighting Programs. PUC Distribution looks forward to promoting energy efficiency programs and assisting its customers in saving money and conserving energy throughout the new 2015-2020 Conservation First Framework.

Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**

  Electricity distributors are required to conduct Connection Impact Assessments (CIAs) within 60 days of receiving authorization for their project from the Electrical Safety Authority. For the year 2010 one CIA request was received and processed within the prescribed timelines.

  In 2011 three requests were received. Two were processed within the prescribed timelines and the progress of the third was not adequately documented so it could not be determined whether it was or was not completed on time. To minimize the likelihood of similar future reporting anomalies, refinements have been made to our CIA application processes and process documents.

  No requests for CIAs were received for the years 2012 through 2014.

- **New Micro-embedded Generation Facilities Connected On Time**

  In 2014, PUC Distribution connected seven new micro-embedded generation facilities (microFIT projects of less than 10 kW) 100% of time within the prescribed time frame of five business days. The minimum acceptable performance level for this measure is 90% of the time.

  Our process to connect these projects is very streamlined and transparent for our customers. PUC Distribution works closely with its customers and their 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 increased from 1.06 in 2013 to 1.68 in 2014 as a result of long term borrowing that was completed late in 2014. PUC Distribution’s current ratio in subsequent years is expected to be in line with 2014 results.

- **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 71% to 29% that approximates the deemed 60% to 40% capital mix as set out by the OEB – this translates to a 2014 debt to equity ratio of 2.42. PUC Distribution’s long range plan is to push the debt to equity towards the deemed 60% to 40%.

- **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% of the expected return on equity. When a distributor performs outside of this range, the actual performance may trigger a regulatory review by the OEB of the distributor’s revenues and costs structure.

- **Profitability: Regulatory Return on Equity – Achieved**

  PUC Distribution’s return on equity in 2014 at 5.47% was more than 3% lower than the expected return of 8.98%. The variance in return on equity is the result of the company’s OM&A expenses in 2014 being approximately $1.1 million higher than included in the approved 2013 cost of service rate application.

Note to Readers of 2014 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management's best judgement on the reporting date of the performance scorecard, and could be markedly different in the future.

Scorecard - PUC Distribution Inc.

9/29/2016

Performance Outcomes	Performance Categories	Measures		2011	2012	2013	2014	2015	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		97.80%	95.80%	96.50%	93.00%	97.20%	🟢↓	90.00%	
		Scheduled Appointments Met On Time		97.20%	98.40%	97.10%	95.40%	97.40%	🟢↓	90.00%	
		Telephone Calls Answered On Time		76.70%	74.60%	80.90%	81.90%	82.30%	🟢↑	65.00%	
	Customer Satisfaction	First Contact Resolution					99.89%	99.92%			
		Billing Accuracy					99.83%	99.36%	🟢↓	98.00%	
		Customer Satisfaction Survey Results					In progess	79%			
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%			
		Level of Compliance with Ontario Regulation 22/04 [1]		NI	NI	C	C	C	🟢↑		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	3	1	3	1	🟢→		1
			Rate per 10, 100, 1000 km of line	0.000	0.407	0.135	0.405	0.134	🟢→		0.151
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		2.92	1.65	2.48	1.19	3.35	🔴↑		2.07
		Average Number of Times that Power to a Customer is Interrupted [2]		3.61	2.17	2.67	1.21	1.84	🟢↓		2.50
	Asset Management	Distribution System Plan Implementation Progress					In progress	In Progress			
	Cost Control	Efficiency Assessment			3	4	4	4			
		Total Cost per Customer [3]		$513	$615	$687	$664	$699			
		Total Cost per Km of Line [3]		$22,981	$27,523	$30,950	$29,886	$31,377			
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%			26.41 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		66.67%				0.00%			
		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)		1.43	1.19	1.06	1.68	0.90			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.44	2.01	1.99	2.42	2.31			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	8.57%	8.57%	8.98%	8.98%	8.98%			
			Achieved	8.16%	4.99%	7.00%	5.47%	4.46%			

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. This measure is under review and subject to change in the future.

Legend:

5-year trend
↑ up ↓ down → flat

Current year
🟢 target met 🔴 target not met

Appendix A – 2015 Scorecard Management Discussion and Analysis (“2015 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 2015 Scorecard MD&A:

http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf

Scorecard MD&A - General Overview

For the year 2015, PUC Distribution met or exceeded all prescribed targets for scorecard measures except one, the outage duration index, SAIDI. This metric was significantly impacted by a late-year winter storm that hit Sault Ste. Marie and surrounding area in the early morning hours of December 24th. With wind gusts up to 90 kph, many trees came down onto PUC distribution lines interrupting power to approximately 10,000 customers for varying time durations. PUC Distribution crews worked extensive hours late into the day on Christmas Eve to restore all affected customers in time for their Christmas Eve dinners. We are very grateful to our staff for their extensive efforts in responding to this demanding weather event and we extend our praise for the excellent work they did in restoring service to all our customers as quickly as possible.

One particular area of performance where PUC Distribution is especially proud of is in the area of safety, both in regards to the general public and in the area of our workers. Of the 36 LDC’s that participated in the 2015 electrical safety awareness survey, PUC Distribution scored the highest with an awareness score of 86%. Our efforts in awareness education for elementary school students and the use of general safety promotions through the various media venues play an important part in this achievement.

Service Quality

- **New Residential/Small Business Services Connected on Time**

  In 2015, PUC Distribution connected 144 eligible low-voltage residential and small business customers (connections under 750 volts) to its distribution system, 97.20% of which were connected within the five-day timeline prescribed by the Ontario Energy Board (OEB). This is an improvement of 4.2 percentage points over 2014 and exceeds the OEB mandated target of 90%. PUC Distribution remains committed to a process of continuous improvement to ensure performance targets are not only met, but exceeded.

- **Scheduled Appointments Met On Time**

  In 2015, PUC Distribution scheduled 1,240 appointments with customers to complete customer requested work (e.g. meter installs or removals, service disconnects or reconnects, and meter locates). As a result of our continuous improvement efforts, PUC Distribution met 97.40% of scheduled appointments, an improvement over 2014 by 2 percentage points, and exceeded the OEB target of 90%.

- **Telephone Calls Answered On Time**

  In 2015, PUC Distribution's Customer Care Department received 38,874 calls from customers. Our Customer Care Representatives answered those calls in 30 seconds or less, 82.30% of the time. This result significantly exceeds the OEB mandated target of 65%. The five year trend has shown continuous improvement for this performance measure in part due to a concerted effort to proactively communicate with our customers. Additionally, the PUC Distribution website is being used more effectively.

Customer Satisfaction

- **First Contact Resolution**

  For 2015, PUC Distribution handled 99.92% of calls without escalating the calls to a; Senior Customer Care Representative, Supervisor, or Manager. However, it's important to note that First Contact Resolution can be measured in a variety of ways, and further regulatory guidance is necessary in order to achieve a meaningful statistic that is comparable across electricity distributors.

  First Contact Resolution was determined by creating two specific call types in our Customer Information System (CIS) which could 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 CIS was queried based on the associated call types to arrive at the total number of customer calls handled by the Customer Care Team.

  To determine the number of repeat calls for the same issue, a review of the escalated calls was conducted on the premise that if the call reached the Senior Customer Care level the concern would not have been satisfactorily resolved at the time of first contact.

- **Billing Accuracy**

  PUC Distribution issued approximately 400,000 bills for the period from January 1, 2015 – December 31, 2015 and achieved an accuracy of 99.36%. This exceeds the prescribed OEB target of 98%. PUC Distribution 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 2015 customer satisfaction survey. The UtilityPulse Electric Utility Survey is in its 17th 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 June and PUC Distribution received a customer satisfaction score of

79% (post survey result). The survey asked customers questions on a wide range of topics, including: overall satisfaction with reliability, customer service, outages, billing and corporate image. These customer satisfaction surveys provide information that supports discussions surrounding improving customer service at all levels and departments within PUC Distribution.

Safety

- **Public Safety**

  The OEB introduced the Safety Measure in 2015. This measure looks at safety from a customer's point of view as safety of the distribution system is a high priority. The Safety Measure is generated by the Electrical Safety Authority (ESA) and includes three components: Public Awareness of Electrical Safety, Compliance with Ontario Regulation 22/04 and the Serious Electrical Incident Index.

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

    In 2015, PUC Distribution participated in a public electrical safety awareness survey. 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). Of the 36 LDC's that participated in the electrical safety awareness survey, PUC Distribution scored the highest with an awareness score of 86%. 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.

    With several major public safety awareness events held in 2015, PUC Distribution's commitment to education and public safety was highlighted once again. Below are the electrical safety initiatives PUC Distribution participated in over the last year:

    - Elementary School Electrical Safety Program for Grade 3 – 5 within our geographic service territory (24 schools involving 1,863 students and their teachers participated)
    - Advanced Research & Technology Innovation Expo (ARTIE) (approx. 360 students and their teachers participated)
    - Sault Ste. Marie Science Festival (approx. 500 adults and children participated)
    - Sault Ste. Marie PUC website – Safety tab
    - Advertisements in the geographic service territory consists of: newspaper and radio ads

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

    Component B is comprised of; an External Audit, a Declaration of Compliance, Due Diligence Inspections, Public Safety Concerns, and

Compliance Investigations. All these elements are evaluated as a whole to determine the status of compliance. Over the past three years, PUC Distribution was found to be compliant with Ontario Regulation 22/04 (Electrical Distribution Safety). This was achieved by our strong commitment to safety and continued adherence to company policies and procedures.

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 installations are put in service.

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

  For 2015, PUC Distribution was below the serious electrical incident target rate of 0.151 incidents per kilometer. PUC Distribution reported one (1) serious electrical incident involving members of the public last year, which is a decrease in the quantity (3) of incidents reported during the previous year. Fortunately, there were no injuries associated with this incident. In following up on this incident, PUC Distribution reached out to the ESA to offer assistance in educating first responders with respect to electrical safety. Additionally, PUC Distribution continues to increase public awareness in an effort to eliminate future incidents. PUC Distribution offers electrical safety awareness outreach via; newspaper and radio, presentations to elementary school students, and detailed hazard awareness presentations to contractors.

System Reliability

- **Average Number of Hours that Power to a Customer is Interrupted**

  The System Average Interruption Duration Index (SAIDI) of 3.35 in 2015 was higher than the target of 2.07. Outage performance for 2015 was significantly impacted by a severe windstorm that hit the Sault Ste. Marie area early on December 24, 2015. The events of that one day accounted for 42% of the outage duration performance for the entire year.

  Excluding the windstorm, SAIDI would have been 1.94. 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 1.84 in 2015 was lower than the target of 2.50. Consistent with SAIDI, outage performance for the year was significantly impacted by a severe windstorm that hit the Sault Ste. Marie area on December 24, 2015. The events of that one day accounted for 31% of the outage frequency performance for the entire year. Excluding the windstorm, SAIFI would have been 1.27.

Asset Management

- **Distribution System Plan Implementation Progress**

  All Distributors are required to file a Distribution System Plan (DSP) when filing a cost of service application for the rebasing of their rates. We expect that implementation of this standardized approach will re-inforce our existing commitment to long term planning and sustainable asset management. PUC Distribution is presently engaged in reviewing, updating, and migrating its Asset Management Plan into the creation of an integrated DSP which will meet all OEB requirements. Accordingly, PUC Distribution plans to file an application with the OEB in 2017 which will include a complete DSP.

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 2015.

Group	Demarcation Points for Relative Cost Performance	% of Ontario LDCs in Group
1	Actual costs are 25% or more below predicted costs	8
2	Actual costs are 10% to 25% below predicted costs	20
3	Actual costs are within +/-10% of predicted costs	51
4	Actual costs are 10% to 25% above predicted costs	15
5	Actual costs are 25% or more above predicted costs	6

In 2015, for the third year in a row, PUC Distribution was placed in Group 4. Group 3 is considered "average efficiency".

PUC Distribution's efficiency performance based on the PEG model was over the predicted costs by 16.2% in 2015 compared to 14.6% in 2014.

- **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 2015 is $699 per customer which is a 5.3 % increase over 2014.

  Overall, the company's Total Cost per Customer has increased on average by 7.3% per annum over the period 2011 through 2015. Similar to most distributors in the province, PUC Distribution has experienced increases in its total costs required to deliver quality and reliable services to customers. Province-wide programs such as Time of Use pricing, growth in wage and benefits costs for employees, as well as investments in new information systems technology and the renewal of the distribution system, have all contributed to increased operating and capital costs.

  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 2015 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 2015 rate is $31,377 per Km of line, a 5.0% increase over 2014.

  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 since 2011 with the increase in capital and operating costs.

Conservation & Demand Management

- **Net Cumulative Energy Savings**

  2015 was a transition year from the previous framework to the new Conservation First Framework. This framework will continue until 2020 with a new MWh target. This transition year allowed LDC's to close out projects from the previous framework and submit new projects under the new framework.

PUC Distribution worked diligently with businesses and channel partners to complete all outstanding projects in addition to updating the changes in rules and submission process for the new framework. As a result of this work, the final net savings for 2015 was 4,538 MWh, slightly better than double our target for the year, and giving us a head start going forward to 2020.

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 the project from the Electrical Safety Authority. For the year 2015, one CIA request was received and processed, however, not within the prescribed timelines. PUC Distribution has adjusted its established process for Generator CIAs to address this issue going forward. .

- **New Micro-embedded Generation Facilities Connected On Time**

  In 2015, PUC Distribution connected six new micro-embedded generation facilities (microFIT projects of less than 10 kW). For those projects, 100% were connected within the prescribed timeframe of five business days. The minimum acceptable performance level for this measure is 90%. PUC Distribution achieved this metric by working closely with our customers and their contractors to ensure the connection process for these types of projects are as streamlined and transparent as possible.

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 decreased from 1.68 in 2014 to 0.90 in 2015. A construction loan of $15M which was in current liabilities was converted to a long term loan in 2016 as planned. The result of this is a reduction of current liabilities of $15M which would increase the current ratio to 2.19.

- **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 2015 debt to equity ratio of 2.31. 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 2015 at 4.46% 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 2015 being approximately $1.3 million higher than included in the approved 2013 cost of service rate application.

Note to Readers of 2015 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management’s best judgement on the reporting date of the performance scorecard, and could be markedly different in the future.

Scorecard - PUC Distribution Inc.

9/11/2017

										Target	
Performance Outcomes	**Performance Categories**	**Measures**		**2012**	**2013**	**2014**	**2015**	**2016**	**Trend**	**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%	↑	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 G

Project Descriptions for Specific Projects Exceeding Materiality Threshold

A. General Information

Project/Activity	#1 - Customer Demand - Services
Project Number	1C100-1
Investment Category	System Access

	2018	2019	2020	2021	2022
Capital Cost (5.4.5.2 A.1)	$ 1,165,797				
Capital Contribution	$ 253,750				
Net Cost	$ 912,047				
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**
	NA	NA	NA	NA	NA

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments and load vary year to year dependent upon quantity and location of customer requests.

Start Date (5.4.5.2 A.3)	Dependent on request	**In Service Date (5.4.5.2 A.3)**	Dependent on request

Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**
	$ 174,870	$ 408,029	$ 408,029	$ 174,870

Project Summary

In an effort to comply with Distribution System Code (DSC) requirements and to support ongoing customer demand, the above values have been budgeted for using historical expenditures and predictions from the City of Sault Ste. Marie regarding projected development. Budgeted expenditures include installations of new/upgraded residential services, commercial services, new transformers to support services, replacement/relocation of infrastructure due to customer requests and other miscellaneous requests from customers. All requests are reviewed against the DSC and reasonableness to determine PUC's contribution level.

Risk Identification & Mitigation (5.4.5.2 A.4)

Tasks occur throughout the year as requested by customers. Risks include internal and contractor resource constraints due to fluctuation of customer requests. PUC is regulated to connect customers who lie along the line within a specified timeframe. In an effort to mitigate the risk of not complying with timelines, PUC reallocates resources from planned capital projects to customer demand as required.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Compared to the previous 5 years, PUC's investment to customer demand, specific to services and accommodating relocation requests is estimated to be low for the next five years. The city has been impacted by uncertainty of local steel industry which, in turn, has impacted the economy. Due to the impact, the housing industry, commercial development and overall spending in the economy has been impacted, reducing the anticipated expenditures in the immediate future to support customer demand. Due to the nature of the economy, this is a prediction and is subject to change.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no REG investments associated with this project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific requests whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

Services will be constructed using USF standards, PUC standards and/or specifics approved by a Professional Engineer.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

PUC is regulated by the OEB Distribution System Code (DSC). The DSC states that all customer that lie along the line of the existing electrical distribution line shall be provided the ability to connect. PUC considers and complies with this requirement to connect new customers as required. PUC provides new connections with the basic connection allowance as specified in the DSC.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

New customer connections, increased revenue and customer relations are the secondary driver for the project. This project will increase quantity of customers supplied by PUC and revise service sizes affecting revenue stream. Replacing/relocating assets to accommodate customers provides PUC with an opportunity to increase customer relations and replace assets at a reduced cost through customer contributions.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

Investment objectives are to comply with all regulations, secure more customers and improve customer relations.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

The City of Sault Ste. Marie is currently preparing a revised population projection for their Official Plan. A preliminary review of the population projection predicts that the population of Sault Ste. Marie will plateau at approximately 75,000 causing a negligible change from today's population. PUC has also referenced the Regional Infrastructure Plan. These documents were referenced when estimating expenditures for the period identified within this cost of service.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project receives a very high priority, immediately behind emergency replacements. This is due to regulatory compliance and customer satisfaction.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

PUC reviews options for new/revised services on a case by case basis to ensure the solution is implemented is safe, low maintenance and economical for all parties.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Net benefits accruing to customers have been qualitatively identified but are unable to quantitatively calculate at this stage.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

There will be no negligible impact to reliability performance resulting from this project. Very minor upgrades to individual services should result in less long term outages for the individual customer.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Alternatives are considered on a case by case basis. The most practical solution is installed considering safety, regulatory, system reliability, economics and customer relations.

Safety (5.4.5.2 B2)

New/upgraded services are installed to the most current safety standards available ensuring safety for all.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

This project has no adverse impact on cyber security or privacy issues.

Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers

Services will be constructed to USF and/or PUC specific standards which are in line with industry standards allowing third parties reasonable access.

Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements

Services and supporting infrastructure are designed to be constructed to USF and/or PUC standards, which are based on meeting the current and future customer needs and distributing electricity reliably, safely and cost effectively.

Economic Development (5.4.5.2 B.5)

By assuring sustainable, reliable, cost effective electrical services to customers in PUC's service territory, this project contributes towards economic development in the region.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

PUC considers different technologies when installing services and supporting infrastructure inclusive of vacuum trucks and directional drilling. These technologies cause less disturbance to the area and in turn less environmental impacts. Additionally, PUC considers environmental impacts when specifying material to be installed.

C. Category-Specific Requirements - System Access

Factors Affecting Timing/Priority (5.4.5.2 SA-C1)

This project receives a very high priority in order for PUC to comply with regulations. Scheduling tasks is dependent on complying with regulations and accommodating customers.

Factors Related to Customer/ Third Party Preferences (5.4.5.2 SA-C2)

PUC informs customers that it is their responsibility to coordinate third party services to be installed. PUC provides contractor information to customer for the customer to obtain benefits of installing multiple utilities in the same excavation. PUC installs services as per USF and/or PUC standards which are in line with industry standards allowing third parties reasonable access.

Factors Affecting the Final Cost (5.4.5.2 SA-C3)

There are many factors that affect the final cost of the project. Costs are affected by how the economy responds, customer requests, regulatory compliance, existing asset life and customer contributions. These costs are vairable and fluctuate annually.

Methods Utilized to Minimize Controllable Costs (5.4.5.2 SA-C4)

PUC considers all options when services are installed/revised in an effort to provide the most practical solution for all parties. PUC has recently began purchasing large, pad mount transformers with integral group operated switches to minimize costs of pole mounted group operated switches and pole changes to obtain the increased space required on the pole. This is one example considered when new/revised services are installed.

Other Planning Objectives (5.4.5.2 SA-C5) (where applicable)

PUC considers other projects when installing new services. If the service is within the area of an upcoming project, it is considered to revise timing of projects to gain overall economic efficiencies. Additionally, adjacent services are grouped together in an attempt to improve efficiency.

Technically feasible project design and/or implementation options exist (5.4.5.2 SA-C6)

Technical options are considered during development of standards and specific designs. Specific products are reviewed in an attempt to improve system safety, reliability and redundancy while managing costs.

Summary of Results Analysis - "Least Cost", "Cost Efficient" options (5.4.5.2 SA-C7)

Options are considered on a case by case basis.

Results of a final Economic Evaluation (5.4.5.2 SA-C8) (where applicable)

If an expansion is identified, PUC will perform an economic evaluation as per section 3.2 of the Distribution System Code. Results of economic evaluation are made available to the customer requesting the expansion.

System impacts costs & cost recovery method (5.4.5.2 SA-C9) (where applicable)

Impacts to the system when connecting a new/revised customer are considered on a case by case basis ensuring the capacity of the system is adequate and impacts to adjacent customers is minimal or positive. Costs and cost recovery is considered on a case by case basis, affected by regulations and corporate practices.

A. General Information

Project/Activity	#2 - Customer Demand - Subdivisions				
Project Number	1C100-2				
Investment Category	System Access				
	2018	**2019**	**2020**	**2021**	**2022**
Capital Cost (5.4.5.2 A.1)	$ 137,153				
Capital Contribution	$ 30,000				
Net Cost	$ 107,153				
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**
	NA	NA	NA	NA	NA

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments and load vary year to year dependent on quantity and location of customer requests.

Start Date (5.4.5.2 A.3)	Dependent on request	**In Service Date (5.4.5.2 A.3)**	Dependent on request

Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**
	$ 20,573	$ 48,004	$ 48,004	$ 20,573

Project Summary

In an effort to comply with Distribution System Code (DSC) requirements and support ongoing customer demand, the above values have been budgeted for using historical expenditures and predictions from the City of Sault Ste. Marie on development. Budgeted values include installations of new subdivisions inclusive of the expansion of our distribution system and transformation up to property lines for projected residential customers. All requests are reviewed against the DSC and reasonableness to determine PUC's contribution level.

Risk Identification & Mitigation (5.4.5.2 A.4)

Tasks occur throughout the year as requested by customers. Risks include internal and contractor resource constraints due to fluctuation of customer requests. PUC provides commitments to subdivision developer's in ways of formal agreements. In an effort to mitigate the risk of not complying with timelines, PUC reallocates resources from planned capital projects to customer demand as required.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Compared to the previous 5 years, PUC's investment to customer demand, specific to subdivisions is estimated to be low/moderate for the next five years. The city has been impacted by uncertainty of local steel industry which, in turn, has impacted the economy. Due to the impact, the housing industry, commercial development and overall spending in the economy has been impacted, reducing the anticipated expenditures in the immediate future to support customer demand. Due to the nature of the economy, this is a prediction and is subject to change.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no REG investments associated with this project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific requests whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

Services will be constructed using USF standards, PUC standards, in coordination with municipal road allowance standards and/or specifics approved by a Professional Engineer.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

PUC is regulated by the OEB DSC. The DSC regulates PUC to provide offers for expansions inclusive of contestable work offered to the developer. PUC considers and complies with all requirements while ensuring all installations add to a safe, efficient, reliable system.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

New customer connections, increased revenue and customer relations are the secondary driver for the project. This project will increase quantity of customers supplied by PUC affecting revenue stream. Expanding the distribution system to connect new subdivisions and in turn, individual customers, provide PUC with an opportunity to improve customer relations.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

Investment objectives are to comply with all regulations, secure more customers and improve customer relations.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

The City of Sault Ste. Marie is currently preparing a revised population projection for their Official Plan. A preliminary review of the population projection predicts that the population of Sault Ste. Marie will plateau at approximately 75,000 causing a negligible change from today's population. PUC has also referenced the Regional Infrastructure Plan. These documents were referenced when estimating expenditures for the period identified within this cost of service. Additionally, PUC communicates frequently with primary subdivision developers inquiring about upcoming plans to ensure PUC is prepared.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project receives a very high priority, immediately behind emergency replacements. This is due to regulatory compliance and customer satisfaction.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

PUC reviews options for system expansions on a case by case basis to ensure the solution is designed and constructed in a safe, low maintenance and economical manner for all parties.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Net benefits accruing to customers have been qualitatively identified but are unable to quantitatively calculate at this stage.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

There will be no negligible impact to reliability performance resulting from typical subdivision developments. Some expansions caused by subdivision developments provide PUC with an opportunity to further loop our system providing additional system redundancy allowing PUC to more effectively reduce outage areas as they occur. Expansions also allow PUC to review circuit and system imbalances and further balance the electrical system through connection of additional demand.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Alternatives are considered on a case by case basis. The most practical solution is installed considering safety, regulatory, system reliability, economics and customer relations.

Safety (5.4.5.2 B2)

System expansions consider safety as paramount by designing and installing to USF standards, PUC standards, in coordination with municipal road allowance standards and/or specifics approved by a Professional Engineer.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

This project has no adverse impact on cyber security or privacy issues.

Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers

System expansions will be designed and constructed to USF and/or PUC specific standards which are in line with industry standards allowing third parties reasonable access.

Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements

System expansions are designed and constructed using USF standards and/or PUC specific standards, which are based on meeting the current and future customer needs and distributing electricity safely, reliably and cost effectively.

Economic Development (5.4.5.2 B.5)

By assuring sustainable, reliable, cost effective electrical services to customers in PUC's service territory, this project contributes towards economic development in the region.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

PUC considers different technologies when installing services and supporting infrastructure inclusive of vacuum trucks and directional drilling. These technologies cause less disturbance to the area and in turn less environmental impacts. Additionally, PUC considers environmental impacts when specifying material to be installed.

C. Category-Specific Requirements - System Access

Factors Affecting Timing/Priority (5.4.5.2 SA-C1)

This project receives a very high priority in order for PUC to comply with regulations. Scheduling tasks is dependent on complying with regulations and accommodating customers.

Factors Related to Customer/ Third Party Preferences (5.4.5.2 SA-C2)

PUC informs developers that it is their responsibility to coordinate third party services to be installed. PUC provides contractor information to developer for the developer to obtain benefits of installing multiple utilities in the same excavation. PUC designs and installs as per USF and/or PUC standards which are in line with industry standards allowing third parties reasonable access.

Factors Affecting the Final Cost (5.4.5.2 SA-C3)

There are uncontrollable factors that affect the final cost of the project. Costs are affected by how the economy responds, customer requests for new developments, regulatory compliance and increased costs in material.

Methods Utilized to Minimize Controllable Costs (5.4.5.2 SA-C4)

PUC strives to manage controllable costs such as labour, equipment and optimizing designs. PUC has started eliminating underground hand boxes from our designs by identifying increased long term O&M costs.

Other Planning Objectives (5.4.5.2 SA-C5) (where applicable)

When designing new system expansions to accommodate subdivisions, PUC considers our system as a whole identifying opportunities to improve safety, reliability and system redundancy.

Technically feasible project design and/or implementation options exist (5.4.5.2 SA-C6)

Technical options are considered during development of standards and specific designs. Specific products are reviewed in an attempt to improve system safety, reliability and redundancy while managing costs.

Summary of Results Analysis - "Least Cost", "Cost Efficient" options (5.4.5.2 SA-C7)

Options are considered on a case by case basis.

Results of a final Economic Evaluation (5.4.5.2 SA-C8) (where applicable)

Values for the OEB regulated Economical Evaluation are completed on a project by project basis. The final values are made available and reviewed with the developer. The costs for the majority of most new expansions to accommodate subdivisions are primarily absorbed by PUC due to quantity of projected future consumption and revenue.

System impacts costs & cost recovery method (5.4.5.2 SA-C9) (where applicable)

Impacts to the system when expanding to accommodate new subdivision developments are considered on a case by case basis ensuring the capacity of the system is adequate and impacts to adjacent neighborhoods are minimal or positive. Cost and cost recovery is considered on a case by case basis, affected by regulations and corporate practices.

A. General Information

Project/Activity	#3 - Customer Demand - Joint Use				
Project Number	1C100-3				
Investment Category	System Access				
	2018	**2019**	**2020**	**2021**	**2022**
Capital Cost (5.4.5.2 A.1)	$ 137,153				
Capital Contribution	$ 40,000				
Net Cost	$ 97,153				
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**
	NA	NA	NA	NA	NA

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments and load vary year to year dependent on quantity and location of customer requests.

Start Date (5.4.5.2 A.3)	Dependent on request	**In Service Date (5.4.5.2 A.3)**	Dependent on request

Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**
	$ 34,288	$ 34,288	$ 34,288	$ 34,288

Project Summary

PUC is a partner with multiple third party communication companies in Sault Ste. Marie. Third party communication companies request to attach to PUC poles in an effort to minimize infrastructure. In doing so, PUC charges a monthly rental fee established in agreements between each company. On a regular basis third party companies will apply for revisions to their existing attachments or for new attachments to be added to coordinate with their business's objectives and customer demand. When applications are received, it is identified whether or not the existing PUC infrastructure is adequate to support the new/revised infrastructure in a safe manner. If PUC's infrastructure requires revisions (make ready work), the work is performed by PUC on a time and material basis.

Risk Identification & Mitigation (5.4.5.2 A.4)

Tasks occur throughout the year as requested by third party companies. Risks include internal and contractor resource constraints due to quantity of requests and other projects occurring. PUC discusses preferred completion dates with the third party companies in an effort to more effectively schedule work. In an effort to mitigate the risk of not achieving discussed timelines, PUC reallocates resources from planned capital projects to customer demand as required.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Historical values for this project vary substantially over the past five years. In 2013 and 2014, Bell Aliant had a business plan to attach fibre optic cable throughout the city to attach to all residential and most commercial customers offering a more advanced service. This project was terminated at approximately 50% completion due to cost. This affected PUC immensely and cause a significant fluctuation in our costs. As these special projects are typically unknown to PUC until last minute, it is near impossible to adjust long term budgets, but react when it occurs. Slight fluctuation is projected from high level discussions with one company.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no REG investments associated with this project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific requests whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

New/Revised attachments will be reviewed against CSA, USF and PUC specific standards. Infrastructure revisions to accommodate third party requests will be completed using USF standards, PUC standards and/or specifics approved by a Professional Engineer.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

PUC is a partner with multiple third party communication companies in Sault Ste. Marie. All attachment points from third party companies result in revenue for PUC. It is important to work collectively to find the optimal solution for all parties. PUC does increase revenue with new third party attachments.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

In being partners with third party communication companies, it is important to minimize infrastructure required to support our systems. This may require shared conduit structures and shared poles in lieu of standalone systems. This provide less conflict in the field and improved customer relations.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

Investment objectives are to comply with contractual requirements and obtain additional revenue through increased quantity of third party attachments.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

Historical averages on expenditures are referenced while eliminating the unique large projects (i.e. Bell Aliant Fibre to the Home) in addition to ongoing conversations with third party communications companies. As majority of their business plans are confidential, PUC is primarily unaware of large projects prior to projects commencing.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project receives a relatively high priority, behind emergency replacements and balanced with general customer demand. This priority is based on continuing good working relationships with third party partners.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

PUC reviews each application for new/revised attachments on a case by case basis to maximize system operation efficiency and cost effectiveness. Make ready work is reviewed and analyzed to maximize benefit for both parties while ensuring cost effectiveness.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

While ensuring safety and reliability of the system are not negatively affected, PUC is able to offset costs with revenue received from third party companies, reducing the impact to customer rates.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

There will be no negligible impact to reliability performance resulting from third party attachment requests. On a case by case review, if PUC observes an opportunity to improve the system for minimal cost in conjunction with the make ready work ready to support the request, the improvement will generally be completed improving system performance.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Alternatives are considered on a case by case basis. The most practical solution is installed considering safety, regulatory, system reliability, economics and customer relations.

Safety (5.4.5.2 B2)

Make ready work to allow new/revised third party attachments on PUC's infrastructure consider safety as paramount by designing and installing to USF standards, PUC standards and/or specifics approved by a Professional Engineer.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

This project has no adverse impact on cyber security or privacy issues.

Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers

Infrastructure revisions will be designed and constructed to USF and/or PUC specific standards which are in line with industry standards allowing third parties reasonable access.

Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements

All make ready work to support new/revised third party attachments is designed and constructed using USF standards and/or PUC specific standards, which are based on meeting the current and future customer needs and distributing electricity safely, reliably and cost effectively.

Economic Development (5.4.5.2 B.5)

By permitting third party companies to attach to PUC's infrastructure in a safe, economical manner this project allows third party communication companies to supply communications throughout PUC's area and beyond, contributing towards economic development in the region.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

PUC considers environmental benefits with each design and installation to minimize environmental impacts.

C. Category-Specific Requirements - System Access

Factors Affecting Timing/Priority (5.4.5.2 SA-C1)

This project receives a relatively high priority, behind emergency replacements and balanced with general customer demand. Scheduling tasks is dependent on complying with contractual requirements, while balancing other projects.

Factors Related to Customer/ Third Party Preferences (5.4.5.2 SA-C2)

PUC currently limits quantity of attachments on a PUC pole to three. Ensuring a single attachment company resides on a maximum of one attachment position allows other third party companies the same potential benefit.

Factors Affecting the Final Cost (5.4.5.2 SA-C3)

There are uncontrollable factors that affect the final cost of the project. Costs are affected by partnering companies and their confidential business plans. Additionally, current state and orientation of PUC's infrastructure in the area of the attachments contributes to the fluctuation of costs.

Methods Utilized to Minimize Controllable Costs (5.4.5.2 SA-C4)

PUC strives to manage controllable costs such as labour, equipment and optimizing designs. PUC continues to review techniques for design (ex. in house vs. external), excavation (ex. vacuum truck), installation (ex. crane use in rear lot) to minimize controllable costs.

Other Planning Objectives (5.4.5.2 SA-C5) (where applicable)

When receiving make ready suggestions during the permit application process, PUC reviews and considers other programs, age of existing infrastructure and customer impacts. PUC ensures that the solution provides benefit to the system to all parties.

Technically feasible project design and/or implementation options exist (5.4.5.2 SA-C6)

Technical options are considered during development of standards and specific designs. Specific products are reviewed in an attempt to improve system safety, reliability and redundancy while managing costs.

Summary of Results Analysis - "Least Cost", "Cost Efficient" options (5.4.5.2 SA-C7)

Options are considered on a case by case basis. Least cost option is not always selected as it is not the most practical.

Results of a final Economic Evaluation (5.4.5.2 SA-C8) (where applicable)

Not applicable

System impacts costs & cost recovery method (5.4.5.2 SA-C9) (where applicable)

Impacts to the system when make ready work is completed for a new/revised third party attachment are considered on a case by case basis ensuring the safety and reliability of the system are not negatively impacted. Costs and cost recovery is as per existing agreements between PUC and third party company.

A. General Information

Project/Activity	#4 - Customer Demand - City Projects				
Project Number	1C100-4				
Investment Category	System Access				
	2018	**2019**	**2020**	**2021**	**2022**
Capital Cost (5.4.5.2 A.1)	$ 274,305				
Capital Contribution	$ 50,000				
Net Cost	$ 224,305				
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**
	NA	NA	NA	NA	NA

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments and load vary year to year dependent on specific projects.

Start Date (5.4.5.2 A.3)	April 1, 2018 (typical)		**In Service Date (5.4.5.2 A.3)**	October 31, 2018 (typical)
Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**
	$ 27,431	$ 137,153	$ 82,292	$ 27,431

Project Summary

Much of PUC's infrastructure is located within the municipal right of way in Sault Ste. Marie and some on right of way owned by the Ministry of Transportation. The City of Sault Ste. Marie conducts complete road reconstructions, storm sewer replacement, curb and asphalt work annually. During these projects, PUC's infrastructure may require relocation/replacement to support the excavation. Due to the "Municipal Act" and specifically the "Public Service Works on Highways Act", PUC is required to relocate/replace infrastructure to support these projects upon request. A cost apportionment is identified in the "Public Service Works on Highways Act" as 100% material and 50% labour to be absorbed by the utility. Extent of the project areas vary from year to year depending on the City's overall plan and dependent on the nature of PUC's infrastructure in the area being addressed.

Risk Identification & Mitigation (5.4.5.2 A.4)

Tasks typically occur between Spring and Fall with majority of the work occurring in early summer in preparation for the road excavations. PUC is regulated to complete the work stated and not completing the work in a reasonable time places PUC at risk of delay charges from the City's contractor. In order to mitigate risks, PUC discusses scope and schedule early in the process to anticipate when work will be required. Placing the project in priority and schedule as well as reallocating resources as required mitigates risk of not completing the work within required timelines.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Historical values are used in conjunction with the City's five year plan. Within the five year plan, specific jobs are identified as large impacts to PUC. Expenditures can significantly vary annually dependent on the areas being addressed, whether PUC's infrastructure will be affected, if PUC's infrastructure is underground or overhead, etc.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no REG investments associated with this project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific requests whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

PUC coordinates and references the City of Sault Ste. Marie's five year capital works program to identify approximate scope of work and requirements for upcoming years. As this plan is subject to change without PUC's approval, PUC's projected expenditures are variable. When revisions occur to PUC's infrastructure to accommodate the above project, all areas revised are reviewed and constructed in compliance with CSA, USF and/or PUC specific standards.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

PUC is required to relocate infrastructure to support highway improvements as defined by the Public Service Works on Highways Act. Scope of work is dependent on the City of Sault Ste. Marie's long term plan.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

During the relocation, it is a possibility for PUC to update infrastructure and gain increased life and increased asset value at a reduced cost due to cost apportionment.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

Investment objectives are to relocate/revise PUC's infrastructure to support City/MTO projects. This allows the projects to progress smoothly while minimizing or eliminating potential safety hazards relating to PUC's infrastructure.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

PUC is required to relocate infrastructure to support highway improvements as defined by the Public Service Works on Highways Act. Scope of work is dependent on the City of Sault Ste. Marie's long term plan. Cost apportionment is generally as per Public Service Works on Highways Act. Historical expenditures have been reviewed in conjunction with the City's five year plan to estimate the required investment.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project receives a relatively high priority, behind emergency replacements and balanced with general customer demand. This priority is based on continuing good working relationships with the City and mitigating risks of delay costs.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

Project has negligible effects on system operation efficiency as the infrastructure is typically replaced in kind after the contractor work has been completed. PUC attempts to coordinate projects to optimize cost effectiveness is feasible.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers continue to benefit from PUC infrastructure located on municipal road allowances, minimizing cost for PUC to install electrical services.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

Frequency of outages once the project has been completed may reduce due to new assets installed.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Alternatives are considered on a case by case basis. The most practical solution is installed considering safety, regulatory, system reliability, economics and customer relations.

Safety (5.4.5.2 B2)

All relocation/replacement work to accommodate City projects consider safety as paramount by designing and installing to USF standards, PUC standards and/or specifics approved by a Professional Engineer.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

This project has no adverse impact on cyber security or privacy issues.

Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers

The project is specific to coordination with the municipality and other utilities to relocate PUC infrastructure to accommodate conflicts. The relocation(s) is designed and constructed to USF standards and/or PUC specific standards, which are in line with industry standards allowing other utilities and third parties reasonable separation and access.

Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements

All relocations to support City projects are designed and constructed using USF standards and/or PUC specific standards, which are based on meeting the current and future customer needs and distributing electricity safely, reliably and cost effectively.

Economic Development (5.4.5.2 B.5)

In coordination with the City, relocating PUC's infrastructure to accommodate road work assist the City to construct municipal infrastructure that will support economic development.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

PUC considers environmental benefits with each design and installation to minimize environmental impacts.

C. Category-Specific Requirements - System Access

Factors Affecting Timing/Priority (5.4.5.2 SA-C1)

This project receives a high priority, behind emergency replacement and balanced within general customer demand and subdivisions. As PUC is not regulated to have this work completed in a defined time, scheduling and coordination is essential to mitigate financial risks to PUC and potential safety risks to contractors.

Factors Related to Customer/ Third Party Preferences (5.4.5.2 SA-C2)

Third party companies are invited to planning, design and construction meetings to ensure they are aware of the relocations. Third party companies are able to discuss specifics with PUC at all stages in an effort to minimize costs for all parties.

Factors Affecting the Final Cost (5.4.5.2 SA-C3)

Final cost of this project are extremely variable. The costs depend on the impacts each project area has on PUC infrastructure, whether it is approved by City Council to proceed and/or the Contractor's requirements during the project.

Methods Utilized to Minimize Controllable Costs (5.4.5.2 SA-C4)

PUC reminds the City of the importance to have PUC in the planning and design meetings to ensure everyone is aware of the impacts and potential costs to relocate the infrastructure. This allows the design team to revise the design to minimize impacts to PUC's infrastructure if feasible. If relocation requirements remain, coordination and scheduling are essential to minimize delays, and in turn, costs.

Other Planning Objectives (5.4.5.2 SA-C5) (where applicable)

PUC always considers adjacent projects and programs when relocating infrastructure to maximize benefits. Adjusting priority of projects may be a possibility to maximize benefits for all parties.

Technically feasible project design and/or implementation options exist (5.4.5.2 SA-C6)

Technical options are considered during development of standards and specific designs. Specific products are reviewed in an attempt to improve system safety, reliability and redundancy while managing costs.

Summary of Results Analysis - "Least Cost", "Cost Efficient" options (5.4.5.2 SA-C7)

Options are considered on an area by area basis to ensure the most practical option is chosen.

Results of a final Economic Evaluation (5.4.5.2 SA-C8) (where applicable)

Not applicable

System impacts costs & cost recovery method (5.4.5.2 SA-C9) (where applicable)

Impacts to the system when relocating PUC infrastructure to accommodate City projects is minimal. Cost recovery is typically based upon the cost apportionment set out in the Public Service Works on Highways Act.

A. General Information

Project/Activity	#5 - Forced Overhead Renewal				
Project Number	1C200-1-1				
Investment Category	System Renewal				
	2018	**2019**	**2020**	**2021**	**2022**
Capital Cost (5.4.5.2 A.1)	$ 308,593				
Capital Contribution	$ 56,250				
Net Cost	$ 252,343				
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**
	NA	NA	NA	NA	NA

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments and load vary year to year dependent on outage areas.

Start Date (5.4.5.2 A.3)	1-Jan-18	**In Service Date (5.4.5.2 A.3)**	31-Dec-18

Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**
	$ 77,148	$ 77,148	$ 77,148	$ 77,148

Project Summary

Overhead forced renewal project is intended to cover costs associated with capital asset renewal from unplanned occurrences, typically resulting from weather related occurrences and/or vehicle accidents. When an occurrence occurs, PUC reviews the situation and determines whether a repair (maintenance budget) is adequate or if a complete replacement of the asset is warranted. When a complete replacement is warranted, PUC will replace the asset to today's standards, where feasible.

Risk Identification & Mitigation (5.4.5.2 A.4)

PUC identifies and mitigates risk of outages whenever possible. Through system inspection and asset testing, PUC understands where the majority of our concerning assets are located and place the replacement of those assets in priority. As it is not practical to have a system so robust that no outages occur, complete elimination of outages is not feasible.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

PUC compares historical values for each category to budget for a recent average. As this budget is dependent on externally driven aspects such as weather and traffic accidents, the expenditures are considered on an annual basis and become difficult to predict.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no REG investments associated with this project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific locations whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

Replacements will be constructed using USF standards, PUC standards and/or specifics approved by a Professional Engineer.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

Safety to the public and workers when a fault occurs in the system is the investment main driver. Although the system is protected via fusing, reclosers, relays and breakers, it is imperative that PUC attend site to ensure the site is safe.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

System reliability is a secondary driver. When a fault occurs, it typically causes an outage for a number of customers. PUC strives to provide a reliable system for all of our customers. Minimizing the outage duration contributes to a reliable system improving our CAIDI and SAIDI statistics.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

The investment objectives are to continue a safe electrical system and mitigate the risk of PUC's reliability statistics from decreasing by limiting the duration of outages, providing a safe and reliable electrical system to consumers.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

Historical expenditures have been analyzed in conjunction with age and condition of existing infrastructure. As the infrastructure ages increased forced renewal expenditures should be expected to increase.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project receives the highest priority as it is primarily caused by system outages and safety concerns. Tasks are typically considered emergency in nature.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

Investment to replace assets in an emergency nature will provide increased system reliability as the asset has now been replaced. The investment is not typically performed in a cost effective manner as it is due to emergency. PUC does attempt to make it as cost effective as possible by performing minimal repairs during after hours in an effort to complete full replacement during regular hours at regular rates. Additionally, transformers are set at a run to failure scheme, which is predicted to be the most cost effective method for transformer failure.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers benefit from this project in having outage times reduced and safety concerns managed in a timely fashion. Benefits have not been quantitatively calculated.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

This project has a significant impact on reliability performance. Although this project does not impact the frequency of outages (SAIFI) it does limit the size of the extended outage and reduce the duration of outages (SAIDI, CAIDI).

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

There are no other practical and cost effective alternatives to this project. This project is a reactive based project that receives a very high priority when tasks arise.

Safety (5.4.5.2 B2)

Public and worker safety is a primary driver in this project. By attending the site, making it safe and replacing the failed infrastructure, reduces hazards for both the public and workers. Final installation will be completed as per CSA, USF and/or PUC specific standards which adhere to a high level of safety standards.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

This project has no adverse impact on cyber security or privacy issues.

Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers (where applicable)

Emergency replacement of assets will be constructed to USF and/or PUC specific standards which are in line with industry standards allowing third parties reasonable access.

Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements (where applicable)

Emergency replacements are typically constructed like-for-like, but when practical, they are constructed to USF and/or PUC standards, which are based on meeting the current and future customer needs and distributing electricity reliably, safely and cost effectively.

Economic Development (5.4.5.2 B.5) (where applicable)

By minimizing system outage durations to customers in PUC's service territory, this project contributes towards economic development in the region.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

PUC considers environmental impacts when performing emergency repairs/replacements. These benefits/impacts are balanced with safety and reliability to come to the most practical solution.

C. Category-Specific Requirements - System Renewal

Asset Performance-related operational targets & asset lifecycle optimization policies and practices (refer to 5.2.3 & 5.3.3) (5.4.5.2 SR-C1.1)

This project is non-discretionary and has been allocated a very high priority due to safety and system reliability concerns once a failure has arisen.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR-C1.2)

Information is not proactively available regarding assets that will be replaced due to the nature of the project. Typically, assets that fail on their own are older in nature, with some exceptions. Assets that fail due to external impacts may be any age.

The number of customers in each class potential affected by failure of the assets (5.4.5.2 SR-C1.3)

The number of customers affected by each failure is dependent on the location of the failure and the assets affected. If a single distribution transformer fails, the customers affected should be limited to approximately 15. If the asset failed is a distribution pole supporting the sub transmission line (34.5kV), the customers affected could be up to 50% of the City. Number of customers immediately affected is not within PUC's control. PUC attempts to limit the quantity of customers that experience extended outages by switching, repairing and/or replacing assets.

Quantitative customer impacts (5.4.5.2 SR-C1.4)

It is not feasible to determine quantitative customer impacts for this project ahead of time.

Qualitative customer impacts (5.4.5.2 SR-C1.5)

Customers located in the area of the failure up to the complete distribution and/or sub transmission circuit will be affected by potential power outages caused by failed assets. PUC will strive to minimize duration of all outages by responding and repairing safe and effectively.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have bearing on the criticality and/or cost of failure (5.4.5.2 SR-C1.6)

Impacts to customers vary on a case to case basis. Some examples are extended outages on residential homes heated using electrical heat, commercial properties with extended outages during regular business hours and critical customers who rely on electricity for emergency services. Due to the unknowns and the possibility for loss of electricity being detrimental, PUC responds to each case effectively with the goal to minimize the duration of outages for all customers.

Timing and Priority of Project (5.4.5.2 SR-C2)

This project has been given the highest priority as the failure may cause a safety concern or a system outage.

Consequences for system O&M costs (5.4.5.2 SR-C3)

This project has minimal long term effects on O&M costs. Asset replacements due to failure should not require significant O&M attention in the future. In retrospect, when a rebuild is required, the pole replaced may require additional work which would not be required if the pole was replaced at the same time.

Impact on reliability performance and/or safety (5.4.5.2 SR-C4)

Reliability performance statistics are immediately impacted by this project as it is a project initiated by failures. Safety is also impacted by this project as failures usually may create safety concerns until our staff arrive to fix the problem.

Analysis of Project Benefits and Timing (5.4.5.2 SR-C5)

Project timing is generally considered emergency as the majority of the tasks are based upon system outages or safety concerns. This ranks highest on all of PUC's projects. This project does have a benefit of reacting to outages versus planned replacement for some assets. Transformers are an asset where PUC has chosen to apply a "run to failure" approach. This maximizes the life of the transformer, obtains additional value from the transformer while paying only a slight premium for reactive replacement.

Like for Like Renewal Analysis, Alternatives Comparison (like for like vs. not like for like, timing, rate of replacements, etc.) (5.4.5.2 SR-C6)

Like for like replacements are typical for majority of tasks that arise from outages or safety concerns due to typical timing of tasks. To have the asset designed on the spot after the failure has occurred is not a practical alternative. Proactively designing all potential failure assets is another alternative that is not practical.

A. General Information

Project/Activity	#6 - Forced Underground Renewal				
Project Number	1C200-1-2				
Investment Category	System Renewal				
	2018	**2019**	**2020**	**2021**	**2022**
Capital Cost (5.4.5.2 A.1)	$ 308,593				
Capital Contribution	$ -				
Net Cost	$ 308,593				
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**
	NA	NA	NA	NA	NA

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments and load vary year to year dependent on outage areas.

Start Date (5.4.5.2 A.3)	1-Jan-18		**In Service Date (5.4.5.2 A.3)**	31-Dec-18
Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**
	$ 77,148	$ 77,148	$ 77,148	$ 77,148

Project Summary

Underground forced renewal project is intended to cover costs associated with capital asset renewal from unplanned occurrences, typically resulting from failed underground and/or pad mounted assets and/or vehicle accidents. When an occurrence occurs, PUC reviews the situation and determines whether a repair (maintenance budget) is adequate or if a complete replacement of the asset is warranted. When a complete replacement is warranted, PUC will replace the asset to today's standards, where feasible.

Risk Identification & Mitigation (5.4.5.2 A.4)

PUC identifies and mitigates risk of outages whenever possible. Through system inspection and asset testing, PUC understands where the majority of our concerning assets are located and place the replacement of those assets in priority. As it is not practical to have a system so robust that no outages occur, complete elimination of outages is not feasible.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

PUC compares historical values for each category to budget for a recent average. As this budget is dependent on externally driven aspects such as traffic accidents, the expenditures are considered on an annual basis and become difficult to predict. Limited investment into aging underground infrastructure should result in increased forced replacement and maintenance costs.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no REG investments associated with this project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific locations whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

Replacements will be constructed using USF standards, PUC standards and/or specifics approved by a Professional Engineer.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

Safety to the public and workers when an asset failure occurs in the system is the investment main driver. Although the system is protected via fusing, reclosers, relays and breakers, it is imperative that PUC attend site to ensure the site is safe.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

System reliability is a secondary driver. When an asset failure occurs, it typically causes an outage for a number of customers. PUC strives to provide a reliable system for all of our customers. Minimizing the outage duration contributes to a reliable system improving our CAIDI and SAIDI statistics.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

The investment objectives are to continue a safe electrical system and mitigate the risk of PUC's reliability statistics from decreasing by limiting the duration of outages, providing a safe and reliable electrical system to consumers.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

Historical expenditures have been analyzed in conjunction with age and condition of existing infrastructure. As the infrastructure ages increased forced renewal expenditures should be expected.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project receives the highest priority as it is primarily caused by system outages and safety concerns. Tasks are typically considered emergency in nature.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

Investment to replace assets in an emergency nature will provide increased system reliability as the asset has now been replaced. The investment is not typically performed in a cost effective manner as it is due to emergency. PUC does attempt to make it as cost effective as possible by performing minimal repairs during after hours in an effort to complete full replacement during regular hours at regular rates. Additionally, transformers are set at a run to failure scheme, which is predicted to be the most cost effective method for transformer failure.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers benefit from this project in having outage times reduced and safety concerns managed in a timely fashion. Benefits have not been quantitatively calculated.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

This project has a significant impact on reliability performance. Although this project does not impact the frequency of outages (SAIFI) it does limit the size of the extended outage and reduce the duration of outages (SAIDI, CAIDI).

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

There are no other practical and cost effective alternatives to this project. This project is a reactive based project that receives a very high priority when tasks arise.

Safety (5.4.5.2 B2)

Public and worker safety is a primary driver in this project. By attending the site, making it safe and replacing the failed infrastructure, reduces hazards for both the public and workers. Final installation will be completed as per CSA, USF and/or PUC specific standards which adhere to a high level of safety standards.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

This project has no adverse impact on cyber security or privacy issues.

Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers (where applicable)

Emergency replacement of assets will be constructed to USF and/or PUC specific standards which are in line with industry standards allowing third parties reasonable access.

Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements (where applicable)

Emergency replacements are typically constructed like-for-like, but when practical, they are constructed to USF and/or PUC standards, which are based on meeting the current and future customer needs and distributing electricity reliably, safely and cost effectively.

Economic Development (5.4.5.2 B.5) (where applicable)

By minimizing system outage durations to customers in PUC's service territory, this project contributes towards economic development in the region.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

PUC considers environmental impacts when performing emergency repairs/replacements. These benefits/impacts are balanced with safety and reliability to come to the most practical solution.

C. Category-Specific Requirements - System Renewal

Asset Performance-related operational targets & asset lifecycle optimization policies and practices (refer to 5.2.3 & 5.3.3) (5.4.5.2 SR-C1.1)

This project is non-discretionary and has been allocated a very high priority due to safety and system reliability concerns once a failure has arisen.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR-C1.2)

Information is not proactively available regarding assets that will be replaced due to the nature of the project. Typically, assets that fail on their own are older in nature, with some exceptions. Assets that fail due to external impacts may be any age.

The number of customers in each class potential affected by failure of the assets (5.4.5.2 SR-C1.3)

The number of customers affected by each failure is dependent on the location of the failure and the assets affected. If a single distribution transformer fails, the customers affected should be limited to approximately 15. If the asset failed is a pad mounted sub transmission switch, the customers affected could be up to 50% of the City. Number of customers immediately affected is not within PUC's control. PUC attempts to limit the quantity of customers that experience extended outages by switching, repairing and/or replacing assets.

Quantitative customer impacts (5.4.5.2 SR-C1.4)

It is not feasible to determine quantitative customer impacts for this project ahead of time.

Qualitative customer impacts (5.4.5.2 SR-C1.5)

Customers located in the area of the failure up to the complete distribution and/or sub transmission circuit will be affected by potential power outages caused by failed assets. PUC will strive to minimize duration of all outages by responding and repairing safe and effectively.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have bearing on the criticality and/or cost of failure (5.4.5.2 SR-C1.6)

Impacts to customer vary on a case to case basis. Some examples are extended outages on residential homes heated using electrical heat, commercial properties with extended outages during regular business hours and critical customers who rely on electricity for emergency services. Due to the unknowns and the possibility for loss of electricity being detrimental, PUC responds to each case effectively with the goal to minimize the duration of outages for all customers.

Timing and Priority of Project (5.4.5.2 SR-C2)

This project has been given the highest priority as the failure may cause a safety concern or a system outage.

Consequences for system O&M costs (5.4.5.2 SR-C3)

This project has minimal long term effects on O&M costs. Asset replacements due to failure should not require significant O&M attention in the future. In retrospect, when a rebuild is required, the underground asset replaced may require additional work which would not be required if the entire area was rejuvenated at the same time.

Impact on reliability performance and/or safety (5.4.5.2 SR-C4)

Reliability performance statistics are immediately impacted by this project as it is a project initiated by failures. Safety is also impacted by this project as failures usually may create safety concerns until our staff arrive to fix the problem.

Analysis of Project Benefits and Timing (5.4.5.2 SR-C5)

Project timing is generally considered emergency as the majority of the tasks are based upon system outages or safety concerns. This ranks highest on all of PUC's projects. This project does have a benefit of reacting to outages versus planned replacement for some assets. Transformers are an asset where PUC has chosen to apply a "run to failure" approach. This maximizes the life of the transformer, obtains additional value from the transformer while paying only a slight premium for reactive replacement.

Like for Like Renewal Analysis, Alternatives Comparison (like for like vs. not like for like, timing, rate of replacements, etc.) (5.4.5.2 SR-C6)

Like for like replacements are typical for majority of tasks that arise from outages or safety concerns due to typical timing of tasks. To have the asset designed on the spot after the failure has occurred is not a practical alternative. Proactively designing all potential failure assets is another alternative that is not practical.

A. General Information

Project/Activity	#7 - Substation 16 Rebuild
Project Number	1C300-3-7 - A
Investment Category	System Renewal

	2018	**2019**	**2020**	**2021**	**2022**
Capital Cost (5.4.5.2 A.1)	$ 419,687				
Capital Contribution	$ -				
Net Cost	$ 419,687				
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**

Customer Attachments and Load (5.4.5.2 A.2)

Number of Customers fed from Sub 16 Feeders: Approximately 2417
Load Impacted: Approximately 10MW annual average

Start Date (5.4.5.2 A.3)	1/7/2016	**In Service Date (5.4.5.2 A.3)**	12/20/2019

Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**
	$ 104,922		$ 209,844	$ 104,922

Project Summary

As detailed in the Asset Management Plan, this substation has been in service for just under 50 years, is in very poor condition and has reached end of life. The planned Sub 16 rebuild is an upgrage from a 34.5k -12.47/7.2kV, 15MVA station to a 34.5kV - 12.47/7.2kV, 26.6MVA substation that will have two incoming 34.5kV supplies, two 10/13.3 MVA power transformers, and four outgoing 12.47kV feeders supplied by arc resistant metalclad switchgear. 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 distribution lines, which significantly reduces reliability and contigency buffers for connected customers.

Risk Identification & Mitigation (5.4.5.2 A.4)

PUC does not have the resource requirements to design and construct substations. The work of the detailed design and construction will be outsourced to an experienced and reputable consultant and contractor to mitigate risks during the project implementation. No risks are anticipated with the proposed outsourcing plan. PUC plans to bypass the Sub 16 34.5kV feeds during the construction phase in order to keep the dual feed supplying affected customers, as referenced above in the Project Summary section.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

PUC's Substation 10 rebuild was completed in 2015 for a total of $4,483,000 and the total estimated cost of the Sub 16 rebuild is $3,910,244.00. Sub 16 is estimated to be less than Sub 10 due to a different switchgear type being used which will allow the building sfootprint to be reduce by about 40%.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

The protection relays are modern micro-processor and IP based relays that are capable of reverse power flow to accommodate REG applications.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

This project does not fall in the category requiring leave to construct.

Attach other project reference material i.e. images, drawings and or reference material

"1C300-3-7 - EST 3707 - DSP Material Capital Asset Justification - Sub 16 Rebuild Attachment 1"

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

Power supply reliability is the key driver for this project. This project will reduce the risk of prolonged power interruptions and reduce the frequency of power interruptions due to equipment failure at Sub 16.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

Operating efficiency is the secondary driver to this project. New switchgear and protection and control equipment will improve operating abilities, and reduce operating costs.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

The investment objectives are to mitigate the risk of power outage duration and frequency falling below PUC's performance targets as outlined on it's OEB annual LDC scorecard.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

The source for information for justification of this project is the Asset Management Plan, which was prepared by taking into account all relevant information pertaining to the condition of station and and lines assets.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project has been determined as a high priority due to the old age and very poor condition of power transformers and switchgear at the existing Sub 16.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

There are no economical alternatives to this project.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Net benefits accruing to customers have been qualitatively described above but have not been quantitatively calculated because accurate information on customer interruption costs is not readily available.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

This project, by reducing the risk of in-service equipment failures, will reduce the risk of prolonged or highly frequent outages. It mitigates the risk of reliability performance falling below PUC's targets as outlined on its OEB annual scorecard.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

There are no other practical and cost effective design or funding alternatives, or co-ownership options available. This project received a high priority based on the criteria presented in the Asset Management Plan.

Safety (5.4.5.2 B2)

Modern protection and controls, capable of automatically responding to mitigate unsafe conditions on the distribution system will be implemented, thus mainting public safety in PUC's service territory.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

The SCADA and protection and control systems will be connected to PUC's fibre network connecting most of PUC owned facilities. This fibre network is protected by PUC's corporate IT managed services which utilizes NIST cybersecurity standards and regulations.

Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers (where applicable)

The protection and controls meeting interoperability standards will be specified and implemented for this project. Power transformers and switchgear conforming to ESA, CSA, and IEEE standards will be utilized.

Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements (where applicable)

The protection relays are modern micro-processor and IP based relays that are capable of reverse power flow to accommodate REG applications. The relays are also capable of being incorporated into PUC's IESO mandated Under-Frequency Load Shedding scheme.

Economic Development (5.4.5.2 B.5) (where applicable)

The substation will be sized with consideration for future load growth within its service territory. By assuring a sustainable reliability of the power system in PUC's service territory, this project contributes towards economic development in the region. Also, the protection and control system will be able to support large REG applications. Lastly, residents or businesses will not have an issue developing near the substation as the layout and design is non obtrusivecally with landscaping and brick type exterior matched to the surrounding land uses. The transformer bays will also have barrier walls to limit transformer hum to below MOE limits.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

Transformer Oil Containment systems will be built into the design to mitigate the environmental risks caused by a transformer failure and oil spill.

C. Category-Specific Requirements - System Renewal

Asset Performance-related operational targets & asset lifecycle optimization policies and practices (refer to 5.2.3 & 5.3.3) (5.4.5.2 SR-C1.1)

This project was prioritized through asset life cycle optimization techniques as detailed in the PUC's Asset Management Plan.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR-C1.2)

As seen in the Asset Management Plan, the condition of the existing assets at Sub 16 has been determined as poor or very poor, presenting a high risk of failure. Sub 16's SCADA RTU has been failed since the winter of 2017 which results in all troubleshooting and operations being performed through site visits and there is a lack of real time knowledge when equipment fails. Also, 24VDC protection relays are no longer available and a workaround power supply conversion was required aroud 2013 to allow newer 125VDC relays to be installed where several 1980s vintage relays were failing timing tests. Lastly, one of the two 7.5MVA transformers failed and wos repaired approximately 7 years ago at considerable expense.

The number of customers in each class potentially affected by failure of the assets (5.4.5.2 SR-C1.3)

Number of Residential Customers: 1975
Number of General Service <50kW: 396
Number of General Service >50kW: 46

Quantitative customer impacts (5.4.5.2 SR-C1.4)

The main impact of this project on customers served from Sub 16 are mitigating the risk of SAIFI and SAIDI worsening due to the anticipated failures of the equipment determined to be in poor or very poor condition.

Qualitative customer impacts (5.4.5.2 SR-C1.5)

Customer satisfaction will improve with the rebuild of Sub 16 as the risk of failure and the potential for reduced outage impacts.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have bearing on the criticality and/or cost of failure (5.4.5.2 SR-C1.6)

The station currently supports one of the fasted growing areas of development in the city along the north Highway 17 corridor and this growth is expected to continue for the foreseeable future. A new hospital was added in the area about 7 years ago and both C&I and subdivision developments continue to spring up. With the poor condition of assets in the existing Sub 16 and the growing customer base, impacts of reliability are affecting more and more customers as time goes on.

Timing and Priority of Project (5.4.5.2 SR-C2)

This project is given a high priority when compared to other projects. Substation 16 is on the edge of town with some long distance feeders and PUC will be pushing other stations, that are picking up the load during the construction, to their limits if the rebuild extends into the winter (high loading) months.

Consequences for system O&M costs (5.4.5.2 SR-C3)

The new Sub 16 will reduce O&M when compared to the existing Sub 16 O&M requirements. The existing station contains open bus and switches on lattice structures with equipment exposed to the harsh northern Ontario environment. The new station will have all equipment except transformers fully enclosed and the type of switchgear to be utilized has monitoring capabilities and minimal maintenance requirements.

Impact on reliability performance and/or safety (5.4.5.2 SR-C4)

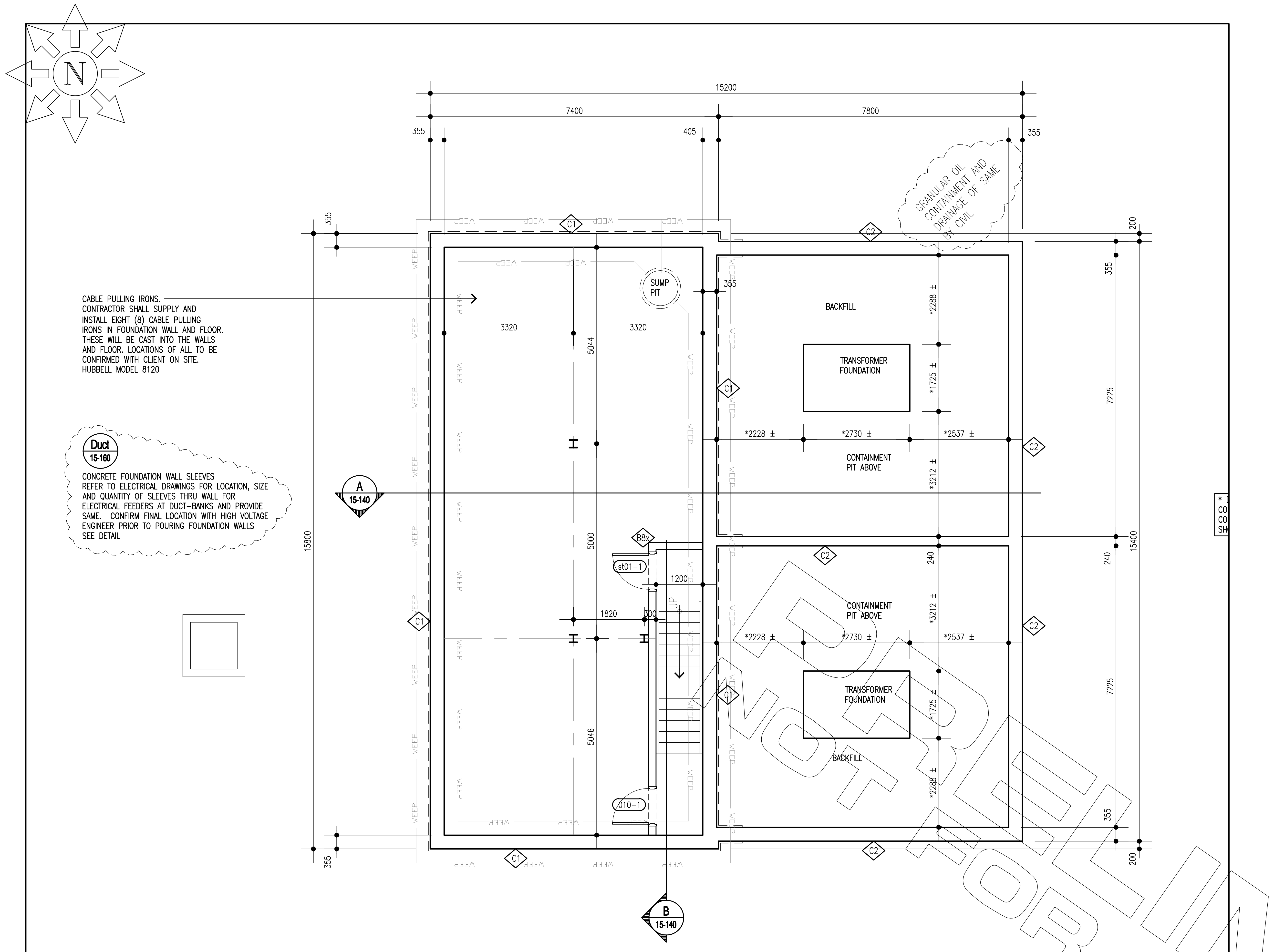
As mentioned above the modern micro-processor based protection relays and new switchgear will offer major benefits for operating safety and public safety by reacting to faults on the system. Also, the transformers will be separated by a firewall, have oil containment, and be surrounded by noise reducing exterior walls. The rebuild of Sub 16 will increase system reliability and safety.

Analysis of Project Benefits and Timing (5.4.5.2 SR-C5)

This project has been given a high priority because it offers a high benefit for risk mitigation and the health its existing equipment was ranked as poor and very poor.

Like for Like Renewal Analysis, Alternatives Comparison (like for like vs. not like for like, timing, rate of replacements, etc.) (5.4.5.2 SR-C6)

The station rebuild will not be like for like as new technology and designs are available to increase operating and maintenance efficiencies. All of the equipment and designs will be specified to meet the current version of applicable standards and to fully meet the current and future needs of customers.

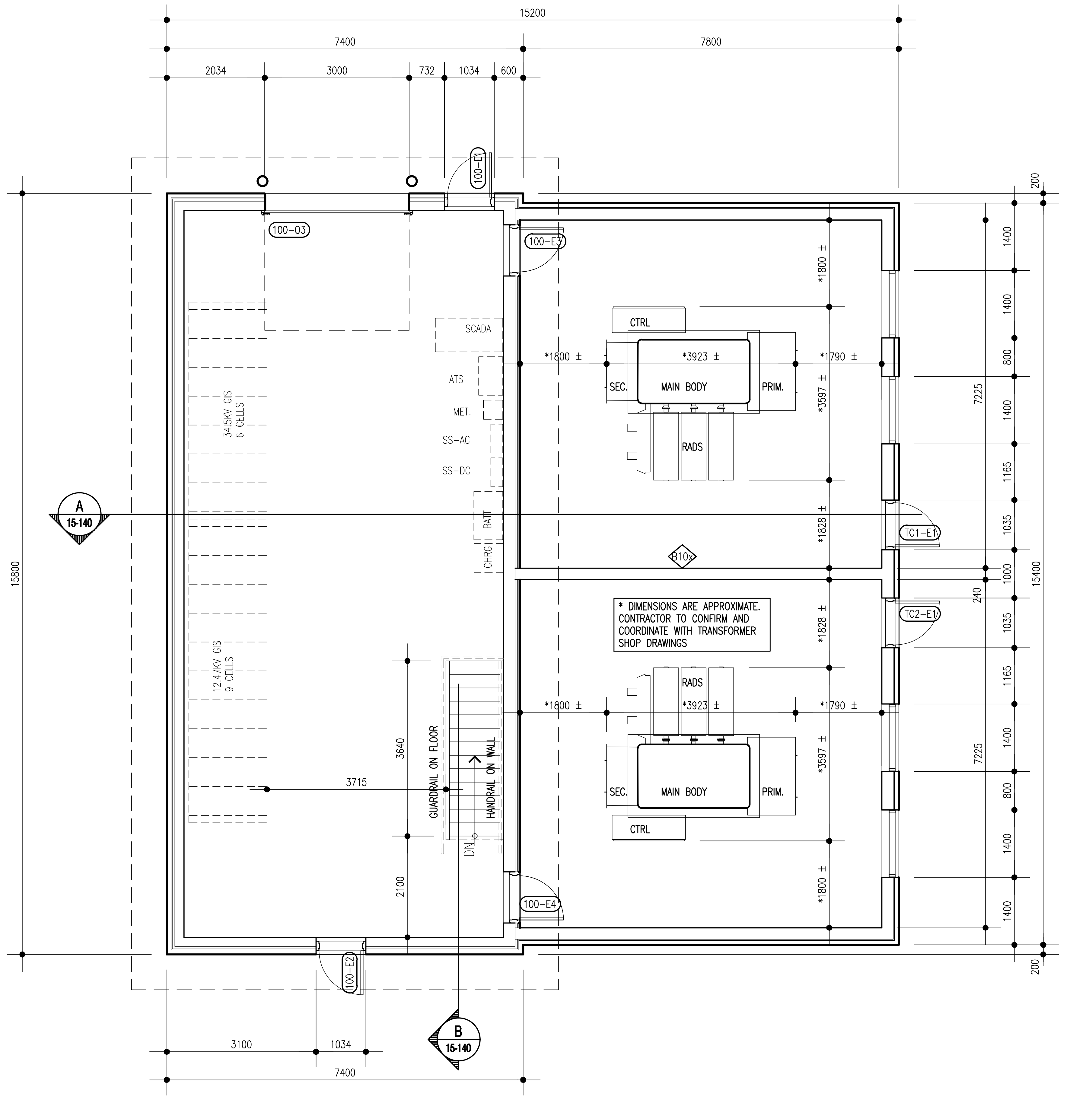


CABLE PULLING IRONS.
CONTRACTOR SHALL SUPPLY AND
INSTALL EIGHT (8) CABLE PULLING
IRONS IN FOUNDATION WALL AND FLOOR.
THESE WILL BE CAST INTO THE WALLS
AND FLOOR. LOCATIONS OF ALL TO BE
CONFIRMED WITH CLIENT ON SITE.
HUBBELL MODEL 8120

Duct
15-160

CONCRETE FOUNDATION WALL SLEEVES
REFER TO ELECTRICAL DRAWINGS FOR LOCATION, SIZE
AND QUANTITY OF SLEEVES THRU WALL FOR
ELECTRICAL FEEDERS AT DUCT–BANKS AND PROVIDE
SAME. CONFIRM FINAL LOCATION WITH HIGH VOLTAGE
ENGINEER PRIOR TO POURING FOUNDATION WALLS
SEE DETAIL

Level 0 Floor Plan
Scale 1:75
Project North



* DIMENSIONS ARE APPROXIMATE.
CONTRACTOR TO CONFIRM AND
COORDINATE WITH TRANSFORMER
SHOP DRAWINGS

Level 1 Floor Plan
Scale 1:75
Project North

NO.	REVISION	DATE	INITIAL

EPOH
architects + engineers + interior design
726 Queen Street East
Sault Ste. Marie ON. CA. P6A 2A9
email: info@epohinc.com
tel: (705) 949-5291 fax: (705) 949-5292

Professional Seal

Check Scale (may be photo-reduced)
0 1 inch 0 10mm

IBI GROUP
IBI Group
30 International Boulevard
Toronto ON M9W 5P3 Canada
tel 416 679 1930
fax 416 675 4620

IBI Project No.: 24RX12.0195

PUC

SCALE: 1:75

SUBSTATION 16

ARCHITECTURAL FLOOR PLANS

DRAWN BY: K.OLIVER
DATE DRAWN:
CHECKED BY: K.OLIVER
DATE CHECKED:
APPROVED BY:
DATE APPROVED:
DWG. NO.: D-ES16-15-120
REV.: A.B.

A. General Information

Project/Activity	#8 - Overhead Renewal - Poles
Project Number	1C300-1-2
Investment Category	System Renewal

	2018	2019	2020	2021	2022
Capital Cost (5.4.5.2 A.1)	$ 314,765				
Capital Contribution	$ -				
Net Cost	$ 314,765				
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**
	NA	NA	NA	NA	NA

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments and load vary year to year dependent on identified deteriorated poles, pole locations and which circuit poles are located on.

Start Date (5.4.5.2 A.3)	1-Jan-18	**In Service Date (5.4.5.2 A.3)**	31-Dec-18

Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**
	$ 125,906	$ 31,477	$ 31,477	$ 125,906

Project Summary

PUC has s significant amount of overhead electrical infrastructure. Within that overhead infrastructure, PUC owns approximately 12,500 poles and are currently joint use on another 3350 Bell Poles. As of 2016 approximately 6% of PUCs poles were either in poor or very poor condition. PUC obtains a third party to perform pole testing on 1/7 of our poles annually that are 10 years or older to determine poles that require immediate attention, short term attention and poles to continue to monitor. Through third party testing and field identification by staff and the public, poles are identified as requiring replacement. This results in the scope of work for the deteriorated pole project for the year. It is estimated that 30 poles will be identified annually for replacement.

Risk Identification & Mitigation (5.4.5.2 A.4)

This project is based on deteriorated pole identification and level of risk identified in the field. Dependent on the level of risk for the poles identified, they may be considered emergency replacements, short term replacements (<1year) or long term replacements (<5years). Dependent on the risk identified, each task will be given a relative priority in an effort to mitigate risks. Resources play a factor in designing and replacing the identified poles. Reallocating resources may be required to mitigate risks.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Historical information is used to average out the cost of a single pole replacement as well as averaging out the quantity of poles that are anticipated to be identified as deteriorated. Estimated expenditure may require revision due to a higher level of identified poles caused by our system aging faster than replacements occurring. Ensuring pole testing is included in O&M budget to effectively retrieve pole strength results should minimize risks of quantity of poles significantly increasing.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no REG investments associated with this project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific locations whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

Replacements will be constructed using USF standards, PUC standards and/or specifics approved by a Professional Engineer.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

Power supply reliability is the primary driver for this project. Proactively identifying poles that are close to failure and proactively replacing them minimizes the risk of a failure occurring. This reduces the risk of prolonged, uncontrolled power outages. Without this project PUC's reliability statistics would be negatively affected.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

Public safety is the secondary driver for this project. Proactively replacing identified poles mitigates the risk of the pole failing in service and controls the hazards to a reasonable level.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

The investment objectives are to continue a safe electrical system and mitigate the risk of PUC's reliability statistics from decreasing by controlling hazards and outages through proactively replacing poles nearing the end of their life.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

Using the age distribution of PUC's poles in conjunction with previous pole testing data and historical quantities of deteriorated poles identified in the field, PUC attempts to accurately predict the quantity of poles that will require replacement. Using historical average costs per pole replacement with the estimated quantity of poles, PUC estimates the expenditures required. Cost vary depending on the quantity of the poles identified and the nature of the poles (ex. 35ft pole vs 65 ft. pole).

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project generally receives the highest priority in relation to PUC's system renewal project, after emergency forced renewal. This prioritization is based upon the risk level of a pole failing in service. The risk level is based upon the nature of the pole and the potential reliability and safety concerns that would arise if the pole fails. PUC reviews identified deteriorated poles and prioritizes each pole within the project.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

The project has minimal effect on system operation efficiency. The project is considered with other projects in an attempt to coordinate projects for cost effectiveness. If this is not practical, the single pole replacements occur. There are no practical alternatives to this project as not replacing the poles will result in asset failures, system reliability concerns and potential public safety concerns.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Proactive pole replacements provide system reliability benefits to customers. Additionally, proactive pole replacements reduce the cost in comparison to reactive replacements upon failure, reducing PUC's overall costs and minimizing impacts to customer's monthly bill.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

Proactive replacement of poles identified as deteriorated reduces the unplanned frequency of outages and significantly reduces the duration of outages. Proactive replacements allow for limited, planned outages to transfer infrastructure in lieu of the unplanned outage. This allows PUC to advise effected customers to allow them to plan for the outage versus react to an outage. Proactive replacements positively impacts reliability statistics.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

Each pole replacement is reviewed on a case by case basis to identify any available alternatives. Some alternatives may include the replacement of two poles with one, additional coordination with adjacent pole owners, etc. Generally, there are no practical alternatives to pole replacements.

Safety (5.4.5.2 B2)

Public safety is a secondary driver for this project. Proactively replacing deteriorated poles reduces the risk of in service failures and the risk of poles and/or live conductors falling to the ground.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

This project has no adverse impact on cyber security or privacy issues.

Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers (where applicable)

Pole replacements will be constructed to USF and/or PUC specific standards which are in line with industry standards allowing third parties reasonable access.

Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements (where applicable)

Pole replacements are typically constructed to USF and/or PUC standards, which are based on meeting the current and future customer needs and distributing electricity reliably, safely and cost effectively.

Economic Development (5.4.5.2 B.5) (where applicable)

By minimizing system outages to customers in PUC's service territory, this project contributes towards economic development in the region.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

PUC considers environmental impacts when replacing poles. This is one of the considerations during the planning stage, selecting installation methods. As much as practical, PUC attempts to minimize environmental impacts.

C. Category-Specific Requirements - System Renewal

Asset Performance-related operational targets & asset lifecycle optimization policies and practices (refer to 5.2.3 & 5.3.3) (5.4.5.2 SR-C1.1)

This project generally receives the highest priority in relation to PUC's system renewal project, after emergency forced renewal. This prioritization is based upon the risk level of a pole failing in service. The risk level is based upon the nature of the pole and the potential reliability and safety concerns that would arise if the pole fails. PUC reviews identified deteriorated poles and prioritizes each pole within the project.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR-C1.2)

Conditions of pole to be replaced are all below acceptable, sustainable condition. The condition is based on visual inspections and third party pole testing. Asset life relative to the typical life cycle is on a case by case basis. Generally, deteriorated poles are beyond the 45 years old, but some poles are identified as deteriorated prior to this due to ground line rot, infestation, woodpecker damage, etc.

The number of customers in each class potential affected by failure of the assets (5.4.5.2 SR-C1.3)

The quantity and class of customers is unknown at this time and is dependent on the poles that are identified as requiring replacement. The quantity and class is variable if the poles are secondary cross over poles versus supporting sub transmission lines (34.5kV)

Quantitative customer impacts (5.4.5.2 SR-C1.4)

It is not feasible to determine quantitative customer impacts for this project ahead of time.

Qualitative customer impacts (5.4.5.2 SR-C1.5)

Customers located in the area of the deteriorated poles identified will benefit from increased system reliability dependent on the nature of the pole.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have bearing on the criticality and/or cost of failure (5.4.5.2 SR-C1.6)

Impacts to customers vary on a case to case basis. Some examples reducing the extended outages on residential homes heated using electrical heat, commercial properties with extended outages during regular business hours and critical customers who rely on electricity for emergency services. Due to the unknowns and the possibility for loss of electricity being detrimental, PUC reviews each identified pole on a case by case basis relating to reliability and safety risks and place poles within replacement schedule.

Timing and Priority of Project (5.4.5.2 SR-C2)

This project generally receives the highest priority in relation to PUC's system renewal project, after emergency forced renewal.

Consequences for system O&M costs (5.4.5.2 SR-C3)

Replacement of deteriorated poles that are beyond 10 years old, reduces O&M costs as PUC tests poles only that are over 10 years old. Treatment of poles has an increased O&M cost which extends the life of certain poles minimizing the required cost within this project.

Impact on reliability performance and/or safety (5.4.5.2 SR-C4)

Reliability performance is directly benefited from replacement of deteriorated poles. This reduces the quantity of unplanned outages which typically result in longer duration outages. This project increases safety by minimizing the risk of pole failures causing potential maintenance and electrical hazards.

Analysis of Project Benefits and Timing (5.4.5.2 SR-C5)

Project timing is generally immediately after emergency replacements and customer demand. System benefits from reducing the quantity of unplanned outages resulting from pole failures.

Like for Like Renewal Analysis, Alternatives Comparison (like for like vs. not like for like, timing, rate of replacements, etc.) (5.4.5.2 SR-C6)

PUC attempts to have all poles replaced within this project designed to USF and/or PUC specific standards. Alternatives are reviewed on a case by case basis to maximize benefits and minimize costs.

A. General Information

Project/Activity	#9 - Overhead Renewal - Restricted Wire (Wallace Terr., 2nd Ave., 5th Ave., 6th Ave., Devon Rd. & Woodcroft Ave.)
Project Number	(2018) 1C300-1-4C
Investment Category	System Renewal

	2018	**2019**	**2020**	**2021**	**2022**
Capital Cost (5.4.5.2 A.1)	$ 433,676				
Capital Contribution	$ -				
Net Cost	$ 433,676				
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**
	NA	NA	NA	NA	NA

Customer Attachments and Load (5.4.5.2 A.2)

Number of Residential Customers: 240
Number of General Service Customers (<50kW): 14
Load Impacted (Tx Ratings): 1007.5kVA

Start Date (5.4.5.2 A.3)	1-Mar-18	**In Service Date (5.4.5.2 A.3)**	31-Dec-18

Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**
	$ 173,470	$ 43,368	$ 43,368	$ 173,470

Project Summary

PUC has identified #6 copper overhead primary conductor as "restricted wire". Due to the nature of the conductor, being small and constructed of copper, it is known to become elongated and brittle over years of use. Due to this, the conductor is prone to failure through breaking. One of the consequences is an increase in the frequency and duration of outages. Additionaly, because conductors present the potential to breaking with minimal disturbances, line workers are 'restricted' to only work on these circuits in a deenrgized state only. This time required to make the worksite safe comes at the cost of more frequent planned outages and higher associated operational costs. When #6 is replaced, it is upgrades to #2ACSR. Usually insulators and any end of live cross arms or poles are addressed at the same time to gain economies of scale. The project is described in more detail within the asset management plan. This area has been identified as a high priority of those remaining in the project.

Risk Identification & Mitigation (5.4.5.2 A.4)

This restricted wire project area is a typical replacement project including replacement of conductor, insulation and other assets such as poles and/or transformers as required. PUC has extensive experience with projects of this nature and through usage of standardized framings, the design and construction should be efficient and straight forward. Project construction may be delayed if unanticipated higher priority unplanned emrgency or customer demand work arises. However, no risks are anticipated which would delay the design or construction of this project significantly.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

PUC has fairly extensive historical information on restricted wire projects and projects of similar nature. Using this information, the length of restricted conductor to be replaced, single phase versus three phase, quantity of poles, quantity of transformers and other unique criteria, PUC is able to reasonably estimate each project without a detailed design being completed beforehand. Variances within project areas may occur that will affect budget, but anticipate that cost variances will even out over the project.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no new REG investments associated with this project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific locations whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

Replacements will be constructed using USF standards, PUC standards and/or specifics approved by a Professional Engineer.

Refer to sketch (2018) 1C300-1-4C for an understanding of the area to be replaced.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

Worker safety is the primary investment driver for this project. As stated in the project summary, the restricted wire can become brittle and break with minimal disturbances. This becomes even more of a concern when PUC and/or third party contractors are working on infrastructure attached to PUC's poles with restricted wire present. Eliminating the restricted wire will eliminate the planned outage times an delay costs associted with making the worksafe safe.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

Economical efficiencies is the secondary driver for this project. PUC's current practice for work on poles containing restricted wire is to take an outage if staff, contractors or joint use telecom parties are working on or below the conductor. By eliminating restricted conductors, PUC reduces the requirements to take outages.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

The investment objectives are to eliminate safety hazards within PUC's electrical distribution system.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

It is common knowledge and well documented across the utility sector that small copper conductors, over time, become brittle and present a safey risk if not adequately manged through costly customer impactive work methods. Most utilities have already eliminated or are in the process of eliminating restricted conductor where it still exists.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project receives a moderate priority, below emergency and system access demands. Due to the nature of the hazard, it is important to continue to remove restricted conductor from service, but working around restricted conductor can be handled through work procedures until all restricted conductor is removed. Not completing this project area in the budget year will cause the project to be extended, resulting in the associated operation and repair costs both stretching out and icreasing over time.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

Completing this project and removing the restricted conductor will have a positive effect on system operation efficiency. Removal of restricted conductor will minimize failures leading to a more efficient, higher reliability system. During the removal of restricted conductors, associated infrastructure (insulators, poles, transformers, etc.) are reviewed and addressed if required.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers benefit from a safer, more reliable system and more cost effective electrical distribution system.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

Through the removal of restricted conductor and replacement associated infrastructure beyond it's useful life will provide a more reliable system, reducing the frequency of outages.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

There are no practical alternatives available for this project area and project as a whole.

Safety (5.4.5.2 B2)

Safety is a primary driver of this project. Removal of restricted conductor eliminates the costs and customer inconveniences associate with routinely isolating circuits to provide adequte worker safety.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

This project has no adverse impact on cyber security or privacy issues.

Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers (where applicable)

Project will be constructed to USF and/or PUC specific standards which are in line with industry standards allowing third parties reasonable access. Where third party providers are currently attached to poles, coordination will occur during design phase.

Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements (where applicable)

Infrastructure replacements are typically constructed to USF and/or PUC standards, which are based on meeting the current and future customer needs and distributing electricity reliably, safely and cost effectively.

Economic Development (5.4.5.2 B.5) (where applicable)

Reducing downtime of PUC's system contributes positively towards economic development in the region.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

PUC considers environmental impacts when replacing infrastructure. Construction techniques are considered to minimize effects on the environment.

C. Category-Specific Requirements - System Renewal

Asset Performance-related operational targets & asset lifecycle optimization policies and practices (refer to 5.2.3 & 5.3.3) (5.4.5.2 SR-C1.1)

This project receives a moderate priority in relation to PUC's system renewal projects, after emergency forced renewal. This prioritization is based upon the safety aspect in conjunction with the reliability concern compared to other projects. Additionally, each project area within the project is reviewed and prioritized compared to one another. Aspects considered are, but not limited to, residential versus rural, vegetation, pedestrian traffic, nearby protective devices. The higher the risk, the higher the priority of the project becomes.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR-C1.2)

The typical age of installation in areas where restricted wire is present is typically mid 1970's or earlier. This results in assets being a minimum 40 years or older. This is generally why restricted wire projects involve more than simply replacing the conductor. Replacing the conductor only, would not be an efficient long term solution and would not bring the value of economies of scale.

The number of customers in each class potential affected by failure of the assets (5.4.5.2 SR-C1.3)

Number of Residential Customers: 240
Number of General Service Customers (<50kW): 14
Load Impacted (Tx Ratings): 1007.5kVA

Quantitative customer impacts (5.4.5.2 SR-C1.4)

It is not feasible to determine quantitative customer impacts for this project ahead of time.

Qualitative customer impacts (5.4.5.2 SR-C1.5)

Customers in the area of this project will benefit from an improved system, higher level of safety and a more reliable electrical distribution system.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have bearing on the criticality and/or cost of failure (5.4.5.2 SR-C1.6)

Impacts to customers can vary on a customer by customer basis. Failure of system to a residential customer will have different impacts depending on the season and if the customer's residence is heated via electric heat or not. If the customer is a commercial customer, outages during regular business hours can impact revenue and therefore an increased cost to the customer. This project will improve system reliability, reduce outage durations and in turn be less impactive to customers.

Timing and Priority of Project (5.4.5.2 SR-C2)

This project generally receives a moderate priority in relation to PUC's system renewal projects. The project is a front lot project fully accessible from the road. Due to the nature of this project in coordination with other projects, this project is scheduled to be constructed early in 2018 and then again late in 2018 with resources shifted to more difficult access projects in the summer.

Consequences for system O&M costs (5.4.5.2 SR-C3)

The project will remove restricted wire and generally replace it with new primary conductor causing a negligible difference in overall system length. Investment in capital through the replacement of aged poles and associated infrastructure is a positive factor with respect to long term operating costs.

Impact on reliability performance and/or safety (5.4.5.2 SR-C4)

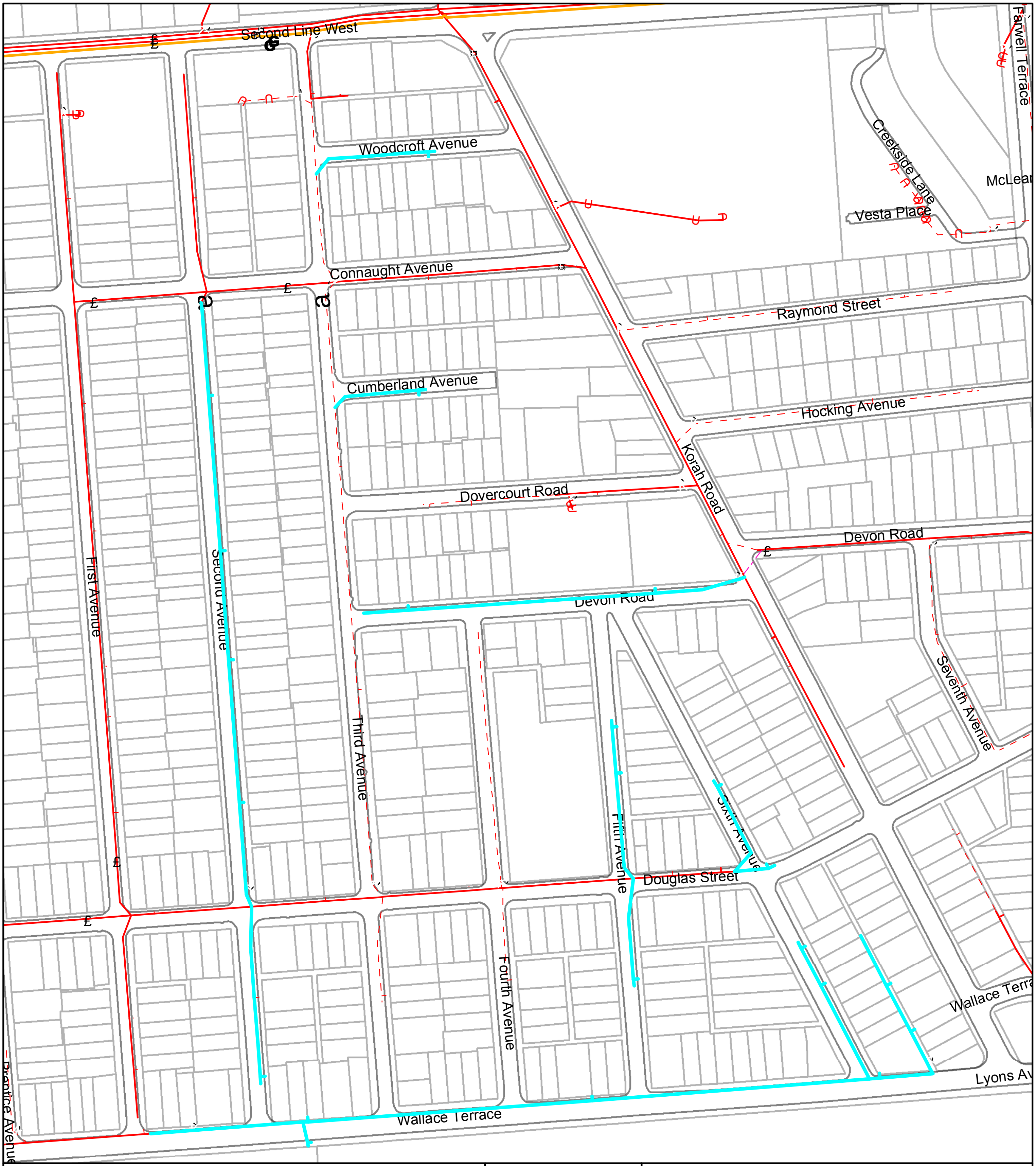
As described above, this project will have a positive impact on worker safety, eliminating the need to put barriers in place and inconvenience customers through outages when working on the distribution system.

Analysis of Project Benefits and Timing (5.4.5.2 SR-C5)

This project generally receives a moderate priority in relation to PUC's system renewal projects. Project timing is considered to optimize all project construction schedules considering access, seasons and customer impacts.

Like for Like Renewal Analysis, Alternatives Comparison (like for like vs. not like for like, timing, rate of replacements, etc.) (5.4.5.2 SR-C6)

While like-for-like replacements may be a possibility, reviewing the distribution system as a whole, replacing and reframing infrastructure will provide the most long term benefit to the system and in turn, the customers. Alternatives to replacing restricted conductor are not available.



Notes:
All locations are approximate as final design has yet to be completed.

N
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SCALE: NTS

SYSTEM PLANNING
2018 - RESTRICTED WIRE
WALLACE TERR, SECOND AVE, FIFTH AVE,
SIXTH AVE, DEVON RD AND WOODCROFT AVE

REV #	REVISION	DATE	INITIAL
A	FOR INFORMATION ONLY	SEP 12/17	JT

PUC

DRAWN BY: J. TEVC	DATE: SEP. 12/17
CHECKED BY:	DATE:
APPROVED BY:	DATE:

DRAWING No.: **(2018)-1C300-1-4C**

REV **A**

A. General Information

Project/Activity	#10 - Underground Renewal - Voltage Conversion (Laronde Ave., Koprash Crt.)
Project Number	(2018) 1C300-2-4
Investment Category	System Renewal

	2018	**2019**	**2020**	**2021**	**2022**
Capital Cost (5.4.5.2 A.1)	$ 531,603				
Capital Contribution	$ -				
Net Cost	$ 531,603				
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**
	NA	NA	NA	NA	NA

Customer Attachments and Load (5.4.5.2 A.2)

Number of Residential Customers: 79
Load Impacted (Tx Ratings): 825kVA

Start Date (5.4.5.2 A.3)	1-Jun-18	**In Service Date (5.4.5.2 A.3)**	31-Aug-18	
Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**
		$ 132,901	$ 398,702	

Project Summary

As shown in PUC's asset management plan, PUC has near 3km of 4.16/2.4kV underground circuits and two 4.16kV distribution stations in service. As the two stations are beyond their anticipated lifespan, replacement will be required. In an effort to bring stations to industry standard, the stations will be replaced with stations producing 12.47/7.2kV distribution voltage. In order to accommodate these station rebuilds all of 4.16/2.4kV underground lines will be required to be converted. Additional to the reliability concerns related to the stations, there are other benefits to convert voltages to a standard 12.47kV including less power losses and standardized equipment allowing for purchasing efficiencies. Coordinating the voltage conversion program with replacing aged, direct buried cables and deteriorated underground vaults provides opportunities through synergies.

Risk Identification & Mitigation (5.4.5.2 A.4)

The underground voltage conversion project inclusive of direct buried cable replacement is fairly new to PUC. PUC has completed two similar projects in the past and have experienced significant variables during the projects. As PUC continues to learn from the variables as they arise and communicate with similar utilities, there are risks of unknowns that may arise. In an effort to mitigate these risks, PUC attempts to include all parties that will be affected early in the planning stage and obtain all information for consideration in designs and planning stages. This project will require construction during the summer months when resources and minimal and resource demands are highest. Reallocating resources to ensure construction is accomplished may be required to mitigate risks of delays.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

PUC has minimal history on similar projects and therefore rely on contractor rates and discussions with other utilities. Customer impacts, restoration, conflicts with adjacent utilities and municipal consent are large factors that can affect expenditures. During design, estimated expenditures are revised to more accurate values. After design, prior to construction, scope of project will be adjusted within or expenditures reassigned as required.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

As customer meters will not be replaced, existing REG customers will not be affected. Transformers will be sized accordingly to accommodate all existing REG customers.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific locations whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

Replacements will be constructed using USF standards, PUC standards and/or specifics approved by a Professional Engineer.

Refer to sketch (2018) 1C300-2-4 for an understanding of the area to be replaced.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

Power supply reliability is the primary investment driver of this project. As stated in the project summary, the supplying stations are beyond their rated life, causing significant reliability concerns. In order to replace the stations to industry standard stations, they will be replaced with a higher distribution voltage. To support these station replacements, the existing 4.16kV lines will require conversion. Additionally, replacement of aged direct buried underground distribution cables, vaults and transformers significantly increase the reliability of the distribution system within the area.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

Cost effectiveness is the secondary investment driver. As the conductors are operating at a lower voltage (4.16kV vs 12.47kV), it is required to feed a larger amount of current through conductors to supply the same amount of power. Voltage conversion will result in a reduction in losses. Additionally, standardizing material allows PUC to store less material, requiring less inventory.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

The investment objectives are to mitigate risk of power supply reliability from degrading below PUC's targets by allowing for end of life distribution stations to be replaced as well as replacing underground cables, vaults and transformers.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

As shown in PUC's asset management plan, distribution stations 4 and 5, currently operating at 4.16kV distribution voltage are nearing end of life. As stated above, this project is to support the replacement of said distribution stations. Additionally, as shown in the asset management plan, PUC has a significant length of underground direct buried cables approaching, if not beyond their rated life. Replacing these cables will mitigate the risk of cable failures occurring.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project receives a moderate priority, below emergency and system access demands. Due to the condition of the distribution systems, it is important to ensure that this project be completed in the budgeted year. Not completing this project in the budgeted year will delay the voltage conversion program, delay the replacement of the 4.16kV distribution stations, continue to operate cables beyond their rated life and, in turn, increase risk of system reliability decreasing.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

Completing this project and in turn the distribution station replacements will have a significant positive effect on system operational efficiency, decreasing power loss costs, improving reliability and decreasing stations maintenance costs. Alternatives are observed on a case by case basis. Installing step down transformers is an alternative reviewed for each area. This is used more for scheduling purpose versus a final solution as it is expenditures that would be lost.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers benefit from a more reliable distribution system with additional supply points and new assets in their immediate subdivision. This should result in less outages, and when an outage occurs, the duration will be limited. Benefits have not been quantitatively calculated for this project.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

This project will positively impact system reliability performance. The project will result in the ability to replace existing, aged distribution stations with new. Additionally, this project will replace all underground cables, vaults and transformers currently installed. Upon completion of the project, the area will be supplied from the 12.47kV system, which has many distribution stations available, resulting in shorter duration outages, if they occur. Additionally, as submersible transformers will be replaced with above ground, minipad transformers, time to complete switching operations and transformer replacements will be reduced.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

There are many project alternatives available for this project, including the installation of step down transformers, cable injection versus replacement, directional drilling verses trenching and replacing submersible transformers in kind verses above ground, minipad transformers. All options are reviewed to ensure the most practical, long term solution is selected.

Safety (5.4.5.2 B2)

In replacement of underground cables, vaults and transformers with new, accommodating a voltage upgrade, the transformers are replaced with above grade, minipad transformers. This provides an increased level of safety around multiple areas. PUC staff are able to operate the minipad transformers in a more ergonomic fashion and less risk to City sidewalk plows from damaging submersible vault lids leaving energized transformers exposed.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

This project has no adverse impact on cyber security or privacy issues.

Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers (where applicable)

Project will be constructed to USF and/or PUC specific standards which are in line with industry standards. PUC coordinates early with third party utilities including communication companies, gas, water and municipality to ensure all parties are both aware of the construction that will be occurring and allow them to coordinate work to provide the maximum benefit to all parties.

Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements (where applicable)

Infrastructure replacements are typically constructed to USF and/or PUC standards, which are based on meeting the current and future customer needs and distributing electricity reliably, safely and cost effectively. Future operational requirements are projected to decrease as maintaining above ground, minipad transformers require significantly less effort than below grade submersible transformers.

Economic Development (5.4.5.2 B.5) (where applicable)

By minimizing system outages to customers in PUC's service territory, this project contributes towards economic development in the region.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

Replacing underground direct buried cables with new, replacing underground submersible transformers in vaults with above ground, minipad transformers has environmental benefits as a potential leaking below grade transformer may go unnoticed for a long time versus an above grade transformer. Additionally, environmental impacts will be considered when installation options are reviewed.

C. Category-Specific Requirements - System Renewal

Asset Performance-related operational targets & asset lifecycle optimization policies and practices (refer to 5.2.3 & 5.3.3) (5.4.5.2 SR-C1.1)

This project receives a moderate priority in relation to PUC's system renewal project, after emergency forced renewal. This prioritization is based upon the risk level of a distribution system infrastructure failure and the immediate reliability impact. Additionally, each area is reviewed in relation to the age of underground infrastructure, history of cable failures, whether cables are direct buried or not and immediate customer impacts. If below grade vaults are causing safety concerns in the area, the project priority is increased within the program.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR-C1.2)

Assets within this area are generally approach or beyond their rated life-cycle. This is based on the age of installation of 4.16kV systems and when cables were direct buried versus installed in conduit. Due to the age of the assets in conjunction with the requirement to increase voltage, most infrastructure is due for replacement.

The number of customers in each class potentially affected by failure of the assets (5.4.5.2 SR-C1.3)

Number of Residential Customers: 79
Load Impacted (Tx Ratings): 825kVA

Quantitative customer impacts (5.4.5.2 SR-C1.4)

It is not feasible to determine quantitative customer impacts for this project ahead of time.

Qualitative customer impacts (5.4.5.2 SR-C1.5)

Customers located in the area of this project will benefit from a more reliable distribution system from new substation builds as well as new cables and transformers in the immediate subdivision.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have bearing on the criticality and/or cost of failure (5.4.5.2 SR-C1.6)

Impacts to customers can vary on a customer by customer basis. Failure of system to a residential customer will have different impacts depending on the season and if the customer's residence is heated via electric heat or not. If the customer is a commercial customer, outages during regular business hours can impact revenue and therefore an increased cost to the customer. This project will improve system reliability, reduce outage durations and in turn be less impactive to customers.

Timing and Priority of Project (5.4.5.2 SR-C2)

This project generally receives a moderate priority in relation to PUC's system renewal projects. The project requires a significant amount of excavation and therefore is most efficient to complete the replacement during summer months.

Consequences for system O&M costs (5.4.5.2 SR-C3)

Replacement of direct buried cables and aged transformers and vaults with new infrastructure including above ground, minipad transformers should reduce system O&M costs. It is expected that anticipated upcoming cable failures will not occur minimize reactive O&M costs.

Impact on reliability performance and/or safety (5.4.5.2 SR-C4)

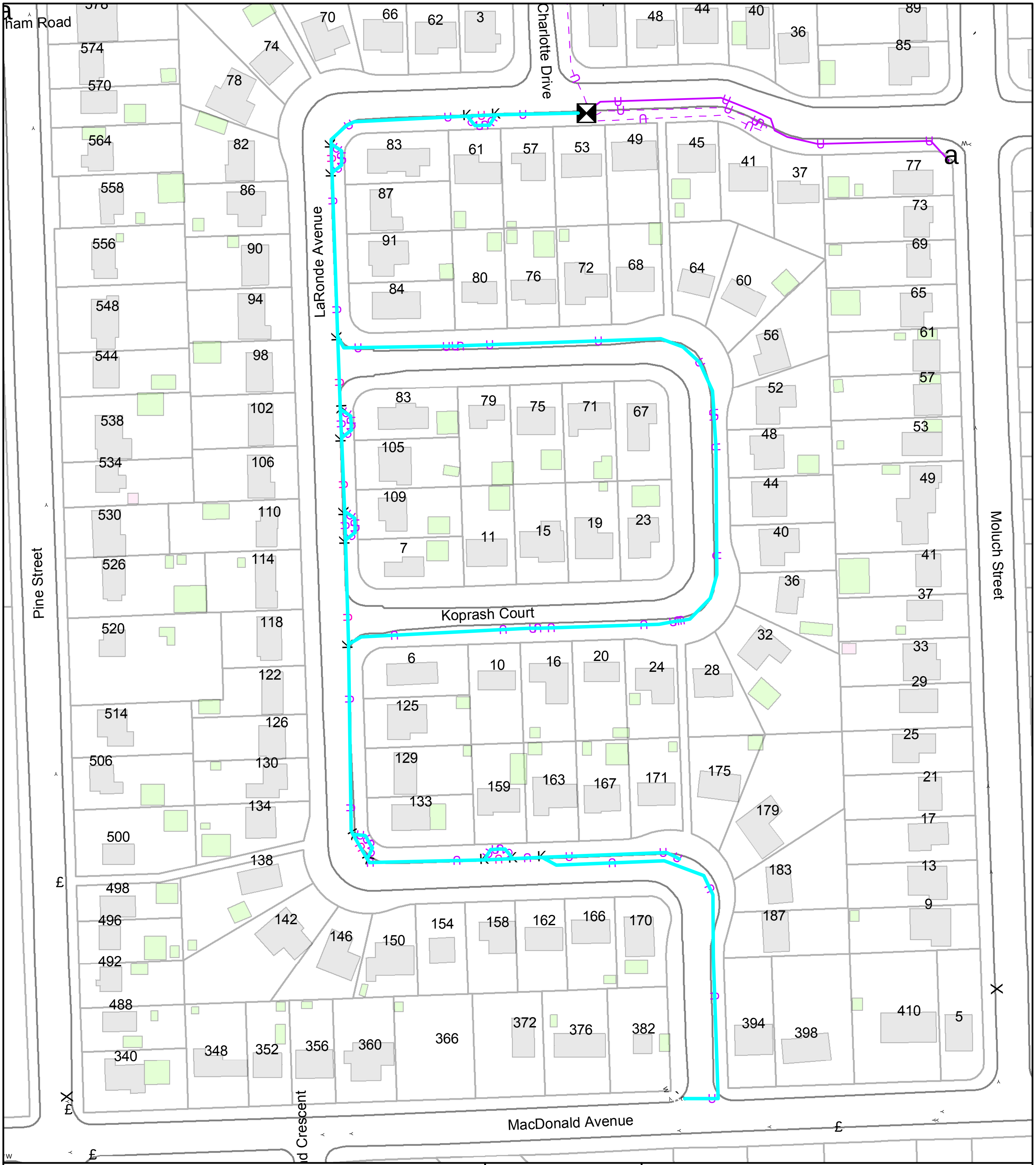
As described above, this project, incoordination with distribution station replacements, should result in improved system reliability and safety.

Analysis of Project Benefits and Timing (5.4.5.2 SR-C5)

This project generally receives a moderate priority in relation to PUC's system renewal projects. Project should be completed in summer months to ensure cost effectiveness. Project will allow aged distribution substations to be replaced and will replace aged distribution cables and transformers resulting in a higher level of reliability.

Like for Like Renewal Analysis, Alternatives Comparison (like for like vs. not like for like, timing, rate of replacements, etc.) (5.4.5.2 SR-C6)

Like-for-like renewal is not an option. Many alternative designs will be considered prior to detailed design including step down transformers, cable injection and directional drilling. After review, PUC will select the most practical solution for the specific project. It is essential to complete this project in the budgeted year as the projects to accommodate the complete voltage conversion have been prioritized and scheduled in conjunction with substation renewals.



Notes:

All locations are approximate as final design has yet to be completed.

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SCALE: NTS

SYSTEM PLANNING
2018 - UG RENEWAL - VOLTAGE CONVERSION
LaRONDE AVE AND KOPRASH CRT

REV #	REVISION	DATE	INITIAL
A	FOR INFORMATION ONLY	SEP 13/17	JT

PUC

DRAWN BY: J. TEVC DATE: SEP. 13/17
CHECKED BY: DATE:
APPROVED BY: DATE:

DRAWING No.:	REV
(2018)-1C300-2-4	A

A. General Information

Project/Activity	#11 - Overhead Renewal - Restricted Wire (Red Pine Drive - North of Pnt. Of Pins)				
Project Number	(2018) 1C300-1-4B				
Investment Category	System Renewal				
	2018	**2019**	**2020**	**2021**	**2022**
Capital Cost (5.4.5.2 A.1)	$ 349,739				
Capital Contribution	$ -				
Net Cost	$ 349,739				
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**
	NA	NA	NA	NA	NA

Customer Attachments and Load (5.4.5.2 A.2)

Number of Residential Customers: 32
Load Impacted (Tx Ratings): 212.5kVA

Start Date (5.4.5.2 A.3)	1-May-18		**In Service Date (5.4.5.2 A.3)**	31-Aug-18
Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**
	$ -	$ 174,870	$ 174,870	$ -

Project Summary

PUC has identified #6 copper overhead primary conductor as "restricted wire". Due to the nature of the conductor, being small and constructed of copper, it is known to become elongated and brittle over years of use. Due to this, the conductor is prone to failure through breaking. One of the consequences is an increase in the frequency and duration of outages. Additionaly, because conductors present the potential to breaking with minimal disturbances, line workers are 'restricted' to only work on these circuits in a deenrgized state only. This time required to make the worksite safe comes at the cost of more frequent planned outages and higher associated operational costs. When #6 is replaced, it is upgrades to #2ACSR. Usually insulators and any end of live cross arms or poles are addressed at the same time to gain economies of scale. The project is described in more detail within the asset management plan. This area has been identified as a high priority of those remaining in the project.

Risk Identification & Mitigation (5.4.5.2 A.4)

This restricted wire project area is a typical replacement project including replacement of conductor, insulation and other assets such as poles and/or transformers as required. PUC has extensive experience with projects of this nature and through usage of standardized framings, the design and construction should be efficient and straight forward. Project construction may be delayed if unanticipated higher priority unplanned emrgency or customer demand work arises. However, no risks are anticipated which would delay the design or construction of this project significantly.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

PUC has fairly extensive historical information on restricted wire projects and projects of similar nature. Using this information, the length of restricted conductor to be replaced, single phase versus three phase, quantity of poles, quantity of transformers and other unique criteria, PUC is able to reasonably estimate each project without a detailed design being completed beforehand. Variances within project areas may occur that will affect budget, but anticipate that cost variances will even out over the project.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no new REG investments associated with this project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific locations whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

Replacements will be constructed using USF standards, PUC standards and/or specifics approved by a Professional Engineer.

Refer to sketch (2018) 1C300-1-4B for an understanding of the area to be replaced.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

Worker safety is the primary investment driver for this project. As stated in the project summary, the restricted wire can become brittle and break with minimal disturbances. This becomes even more of a concern when PUC and/or third party contractors are working on infrastructure attached to PUC's poles with restricted wire present. Eliminating the restricted wire will eliminate the planned outage times an delay costs associted with making the worksafe safe.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

Economical efficiencies is the secondary driver for this project. PUC's current practice for work on poles containing restricted wire is to take an outage if staff, contractors or joint use telecom parties are working on or below the conductor. By eliminating restricted conductors, PUC reduces the requirements to take outages.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

The investment objectives are to eliminate safety hazards within PUC's electrical distribution system.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

It is common knowledge and well documented across the utility sector that small copper conductors, over time, become brittle and present a safey risk if not adequately manged through costly customer impactive work methods. Most utilities have already eliminated or are in the process of eliminating restricted conductor where it still exists.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project receives a moderate priority, below emergency and system access demands. Due to the nature of the hazard, it is important to continue to remove restricted conductor from service, but working around restricted conductor can be handled through work procedures until all restricted conductor is removed. Not completing this project area in the budget year will cause the project to be extended, resulting in the associated operation and repair costs both stretching out and icreasing over time.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

Completing this project and removing the restricted conductor will have a positive effect on system operation efficiency. Removal of restricted conductor will minimize failures leading to a more efficient, higher reliability system. During the removal of restricted conductors, associated infrastructure (insulators, poles, transformers, etc.) are reviewed and addressed if required.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers benefit from a safer, more reliable system and more cost effective electrical distribution system.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

Through the removal of restricted conductor and replacement associated infrastructure beyond it's useful life will provide a more reliable system, reducing the frequency of outages.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

There are no practical alternatives available for this project area and project as a whole.

Safety (5.4.5.2 B2)

Safety is a primary driver of this project. Removal of restricted conductor eliminates the costs and customer inconveniences associate with routinely isolating circuits to provide adequte worker safety.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

This project has no adverse impact on cyber security or privacy issues.

Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers (where applicable)

Project will be constructed to USF and/or PUC specific standards which are in line with industry standards allowing third parties reasonable access. Where third party providers are currently attached to poles, coordination will occur during design phase.

Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements (where applicable)

Infrastructure replacements are typically constructed to USF and/or PUC standards, which are based on meeting the current and future customer needs and distributing electricity reliably, safely and cost effectively.

Economic Development (5.4.5.2 B.5) (where applicable)

Reducing downtime of PUC's system contributes positively towards economic development in the region.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

PUC considers environmental impacts when replacing infrastructure. Construction techniques are considered to minimize effects on the environment.

C. Category-Specific Requirements - System Renewal

Asset Performance-related operational targets & asset lifecycle optimization policies and practices (refer to 5.2.3 & 5.3.3) (5.4.5.2 SR-C1.1)

This project receives a moderate priority in relation to PUC's system renewal projects, after emergency forced renewal. This prioritization is based upon the safety aspect in conjunction with the reliability concern compared to other projects. Additionally, each project area within the project is reviewed and prioritized compared to one another. Aspects considered are, but not limited to, residential versus rural, vegetation, pedestrian traffic, nearby protective devices. The higher the risk, the higher the priority of the project becomes.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR-C1.2)

The typical age of installation in areas where restricted wire is present is typically mid 1970's or earlier. This results in assets being a minimum 40 years or older. This is generally why restricted wire projects involve more than simply replacing the conductor. Replacing the conductor only, would not be an efficient long term solution and would not bring the value of economies of scale.

The number of customers in each class potential affected by failure of the assets (5.4.5.2 SR-C1.3)

Number of Residential Customers: 32
Load Impacted (Tx Ratings): 212.5kVA

Quantitative customer impacts (5.4.5.2 SR-C1.4)

It is not feasible to determine quantitative customer impacts for this project ahead of time.

Qualitative customer impacts (5.4.5.2 SR-C1.5)

Customers in the area of this project will benefit from an improved system, higher level of safety and a more reliable electrical distribution system.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have bearing on the criticality and/or cost of failure (5.4.5.2 SR-C1.6)

Impacts to customers can vary on a customer by customer basis. Failure of system to a residential customer will have different impacts depending on the season and if the customer's residence is heated via electric heat or not. If the customer is a commercial customer, outages during regular business hours can impact revenue and therefore an increased cost to the customer. This project will improve system reliability, reduce outage durations and in turn be less impactive to customers.

Timing and Priority of Project (5.4.5.2 SR-C2)

This project generally receives a moderate priority in relation to PUC's system renewal projects. The project is a complex project due to currently being constructed across private property near the shore of Lake Superior. Due to access constraints, it will be optimal to complete project during summer months.

Consequences for system O&M costs (5.4.5.2 SR-C3)

The project will remove restricted wire and generally replace it with new primary conductor causing a negligible difference in overall system length. Investment in capital through the replacement of aged poles and associated infrastructure is a positive factor with respect to long term operating costs.

Impact on reliability performance and/or safety (5.4.5.2 SR-C4)

As described above, this project will have a positive impact on worker safety, eliminating the need to put barriers in place and inconvenience customers through outages when working on the distribution system.

Analysis of Project Benefits and Timing (5.4.5.2 SR-C5)

This project generally receives a moderate priority in relation to PUC's system renewal projects. Project timing is considered to optimize all project construction schedules considering access, seasons and customer impacts.

Like for Like Renewal Analysis, Alternatives Comparison (like for like vs. not like for like, timing, rate of replacements, etc.) (5.4.5.2 SR-C6)

While like-for-like replacements may be a possibility, reviewing the distribution system as a whole, replacing and reframing infrastructure will provide the most long term benefit to the system and in turn, the customers. Alternatives to replacing restricted conductor are not available.

Notes:
All locations are approximate as final design has yet to be completed.

N
W E
S
SCALE: NTS

SYSTEM PLANNING
2018 - RESTRICTED WIRE
RED PINE DR
NORTH OF POINTE AUX PINS DRIVE

REV #	REVISION	DATE	INITIAL
A	FOR INFORMATION ONLY	SEP 12/17	JT

DRAWN BY: J. TEVC DATE: SEP. 12/17
CHECKED BY: DATE:
APPROVED BY: DATE:

DRAWING No.: (2018)-1C300-1-4B
REV A

PUC

A. General Information

Project/Activity	#12 - Overhead Renewal - Voltage Conversion (MacDonald Ave - Lake St. to Moluch St.)				
Project Number	(2018) 1C300-1-3A				
Investment Category	System Renewal				
	2018	**2019**	**2020**	**2021**	**2022**
Capital Cost (5.4.5.2 A.1)	$ 288,020				
Capital Contribution	$ -				
Net Cost	$ 288,020				
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**
	NA	NA	NA	NA	NA

Customer Attachments and Load (5.4.5.2 A.2)

Number of Residential Customers: 25
Number of MicroFit Customers: 1
Load Impacted (Tx Ratings): 187.5kVA

Start Date (5.4.5.2 A.3)	1-Jan-18		**In Service Date (5.4.5.2 A.3)**	30-Apr-18
Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**
	$ 216,015	$ 72,005	$ -	

Project Summary

As shown in PUC's asset management plan, PUC has over 30km of overhead 4.16/2.4kV circuits and two 4.16kV distribution stations in service. As the two stations are beyond their anticipated lifespan, replacement of the stations will be required. In an effort to bring stations to industry standard, the stations will be replaced with stations producing 12.47/7.2kV distribution voltage. In order to accommodate these station rebuilds, all 30km of line will be required to be converted. Additional to the reliability concerns related to the stations, there are other significant benefits to convert voltages to a standard 12.47kV including less power losses and standardized equipment allowing for purchasing efficiencies.

Risk Identification & Mitigation (5.4.5.2 A.4)

This voltage conversion project should be a typical PUC line rebuild, in which PUC has extensive experience designing and constructing. In using standardized framing standards, the design should be efficient and completed as required. Project implementation may be delayed dependent on unplanned, higher priority work arising. No risks are anticipated which would delay the design or construction of this project significantly.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

PUC has fairly extensive historical information on voltage conversion projects and projects of similar nature. Using this information, the length of conductor to be converted/removed, single phase versus three phase, quantity of poles, quantity of transformers and other unique criteria, PUC is able to reasonably estimate each project without a detailed design being completed beforehand. Variances within projects may occur that will affect budget, but anticipate that program cost variances will even out between projects.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no new REG investments associated with this project. If existing REG customers are attached to the 4.16kV system, they will be transferred over to the 12.47kV system. As they will all be connected on the low voltage side, this will have negligible impacts to the project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific locations whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

Replacements will be constructed using USF standards, PUC standards and/or specifics approved by a Professional Engineer.

Refer to sketch (2018) 1C300-1-3A for an understanding of the area to be converted.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

Power supply reliability is the primary investment driver of this project. As stated in the project summary, the supplying stations are beyond their rated life, causing reliability concerns. In order to replace the stations to industry standard, they will be replaced with a higher distribution voltage. To support these station replacements, the existing 4.16kV lines will require conversion.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

Cost effectiveness is the secondary investment driver. As the conductors are operating at a lower voltage (4.16kV vs 12.47kV), it is required to feed a larger amount of current through conductors to supply the same amount of power. Voltage conversion will result in a reduction in losses. Additionally, standardizing material allows PUC to store less material, requiring less inventory.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

The investment objectives are to mitigate risk of power supply reliability from degrading below PUC's targets by allowing for end of life distribution stations to be replaced.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

As shown in PUC's asset management plan, distribution stations 4 and 5, currently operating at 4.16kV distribution voltage are nearing end of life. As stated above, this project is to support the replacement of said distribution stations.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project receives a moderate priority, below emergency and system access demands. Due to the condition of the distribution systems, it is important to ensure that this project area be completed in the budgeted year. Not completing this project area in the budgeted year will delay the voltage conversion project, delay the replacement of the 4.16kV distribution stations and increase risk of system reliability decreasing.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

Completing this project and in turn the distribution station replacements will have a significant positive effect on system operational efficiency, improving reliability and decreasing stations maintenance costs. Alternatives are observed on a case by case basis. Installing a step down transformer is an alternative reviewed for each area. This is used more for scheduling purpose versus a final solution as expenditures would be lost once final conversion occurs.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers benefit from a more reliable distribution system with additional supply points. This should result in less outages, and when an outage occurs, the duration will be limited. Benefits have not be quantitatively calculated for this project.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

This project will positively impact system reliability performance. The project will result in the ability to replace existing, aged distribution stations with new. Additionally, this project will replace each distribution transformer and insulator used within the 4.16kV system to support the higher voltage resulting in new assets with lower risk of failures. Upon completion of the project area, the area will be supplied from the 12.47kV system, which has many distribution stations available, resulting in shorter duration outages, if they occur.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

There are no practical and cost effective alternative designs for this project that provide the same level of benefits to customers.

Safety (5.4.5.2 B2)

In order to convert voltages within this project, many transformers will require replacement. Framing, inclusive of separations on existing poles may be well below current standards. In order to ensure separations are achieved and working space is considered, many poles beyond their useful life will require replacement. In replacing poles, safety is increased for both the work (working space) and the public (new asset).

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

This project has no adverse impact on cyber security or privacy issues.

Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers (where applicable)

Project will be constructed to USF and/or PUC specific standards which are in line with industry standards allowing third parties reasonable access. Where third party providers are currently attached to poles, coordination will occur during design phase.

Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements (where applicable)

Infrastructure replacements are typically constructed to USF and/or PUC standards, which are based on meeting the current and future customer needs and distributing electricity reliably, safely and cost effectively.

Economic Development (5.4.5.2 B.5) (where applicable)

By minimizing system outages to customers in PUC's service territory, this project contributes towards economic development in the region.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

PUC considers environmental impacts when replacing infrastructure. Many existing 4.16/2.4kV, pole mounted transformers are well aged transformers, typically manufactured prior to the 1980's, resulting in a posibility of containing PCB levels exceeding the acceptable 50ppm. During this project, all 4.16kV transformers will be removed, mitigating environmental risks in an occurance of transformer oil leaking.

C. Category-Specific Requirements - System Renewal

Asset Performance-related operational targets & asset lifecycle optimization policies and practices (refer to 5.2.3 & 5.3.3) (5.4.5.2 SR-C1.1)

This project receives a moderate priority in relation to PUC's system renewal project, after emergency forced renewal. This prioritization is based upon the risk level of a distribution system infrastructure failure and the immediate reliability impact. Additionally, each area is reviewed in relation to the age of infrastructure, deteriorated poles, restricted wire, etc. to ensure all aspects are considered during prioritization. Increased safety concern would increase project prioritization.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR-C1.2)

Assets within this projects are generally beyond their typical life-cycle. This is based on the age of installation of 4.16kV systems, specific to these areas. Due to this, in conjunction with pole testing records, most of the infrastructure is due for replacement. This is considered during conversion for efficiencies.

The number of customers in each class potential affected by failure of the assets (5.4.5.2 SR-C1.3)

Number of Residential Customers: 25
Number of MicroFit Customers: 1
Load Impacted (Tx Ratings): 187.5kVA

Quantitative customer impacts (5.4.5.2 SR-C1.4)

It is not feasible to determine quantitative customer impacts for this project ahead of time.

Qualitative customer impacts (5.4.5.2 SR-C1.5)

Customers located in the area of this project will benefit from a more reliable distribution system as well as new infrastructure providing for a higher level of safety.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have bearing on the criticality and/or cost of failure (5.4.5.2 SR-C1.6)

Impacts to customers can vary on a customer by customer basis. Failure of system to a residential customer will have different impacts depending on the season and if the customer's residence is heated via electric heat or not. If the customer is a commercial customer, outages during regular business hours can impact revenue and therefore an increased cost to the customer. This project will improve system reliability, reduce outage durations and in turn be less impactive to customers.

Timing and Priority of Project (5.4.5.2 SR-C2)

This project generally receives a moderate priority in relation to PUC's system renewal projects. The project is a front lot project fully accessible from the road. Due to the nature of this project in coordination with other projects, this project is scheduled to be constructed during Q1 of 2018.

Consequences for system O&M costs (5.4.5.2 SR-C3)

This project will convert an existing line with similar length of a new line causing negligible O&M impacts. Replacement of poles and infrastructure during the project should be a positive contributing factor pertaining to outages and repairs, reducing potential O&M costs.

Impact on reliability performance and/or safety (5.4.5.2 SR-C4)

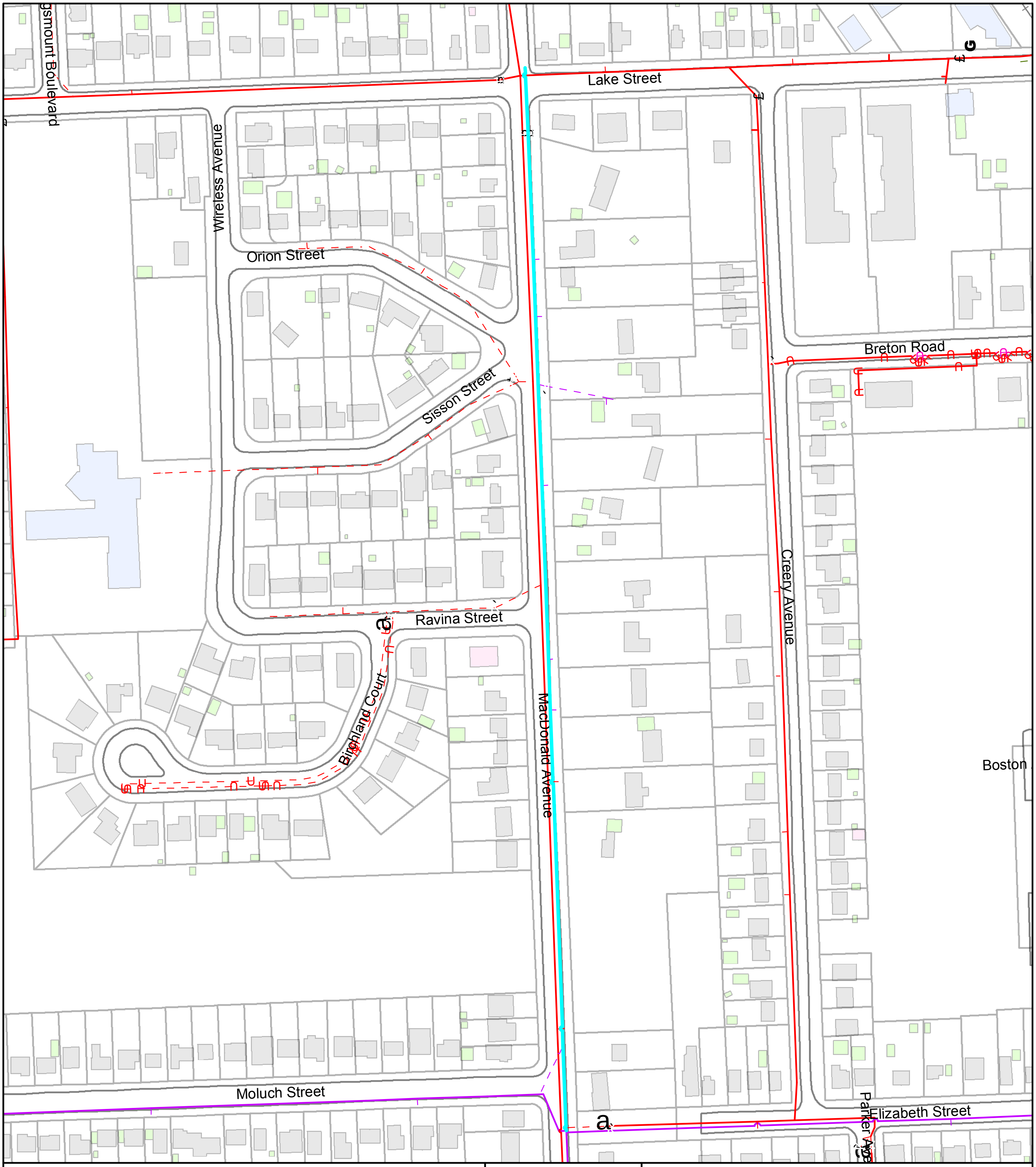
As described above, this project, in coordination with distribution station replacements, should result in improved system reliability and safety.

Analysis of Project Benefits and Timing (5.4.5.2 SR-C5)

This project generally receives a moderate priority in relation to PUC's system renewal projects. Project timing is considered to optimize all project construction schedules considering access, seasons and customer impacts.

Like for Like Renewal Analysis, Alternatives Comparison (like for like vs. not like for like, timing, rate of replacements, etc.) (5.4.5.2 SR-C6)

While like-for-like replacements may be a possibility, reviewing the distribution system as a whole, replacing and reframing infrastructure will provide the most long term benefit to the system and in turn, the customers. Alternatives are reviewed on a case by case basis to maximize benefits and minimize costs.



Notes:

All locations are approximate as final design has yet to be completed.

SCALE: NTS

SYSTEM PLANNING
2018 - VOLTAGE CONVERSION
MacDONALD AVE.
LAKE ST. TO MOLUCH ST.

REV #	REVISION	DATE	INITIAL
A	FOR INFORMATION ONLY	SEP 08/17	JT

PUC

DRAWN BY: J. TEVC DATE: SEP. 08/17

CHECKED BY: DATE:

APPROVED BY: DATE:

DRAWING No.: **(2018)-1C300-1-3A**

REV **A**

A. General Information

Project/Activity	#13 - Overhead Renewal - Restricted Wire (Carpin Beach Road - Base Line to Herkimer, Phase 1 of 2)				
Project Number	(2018) 1C300-1-4A				
Investment Category	System Renewal				
	2018	**2019**	**2020**	**2021**	**2022**
Capital Cost (5.4.5.2 A.1)	$ 185,155.00				
Capital Contribution	$ -				
Net Cost	$ 185,155.00				
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**
	NA	NA	NA	NA	NA

Customer Attachments and Load (5.4.5.2 A.2)

Number of Residential Customers: 12
Load Impacted (Tx Ratings): 137.5kVA

Start Date (5.4.5.2 A.3)	1-Sep-18	**In Service Date (5.4.5.2 A.3)**	31-Oct-18

Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**
	$ -	$ -	$ 92,577.50	$ 92,577.50

Project Summary

PUC has identified #6 copper overhead primary conductor as "restricted wire". Due to the nature of the conductor, being small and constructed of copper, it is known to become elongated and brittle over years of use. Due to this, the conductor is prone to failure through breaking. One of the consequences is an increase in the frequency and duration of outages. Additionaly, because conductors present the potential to breaking with minimal disturbances, line workers are 'restricted' to only work on these circuits in a deenrgized state only. This time required to make the worksite safe comes at the cost of more frequent planned outages and higher associated operational costs. When #6 is replaced, it is upgrades to #2ACSR. Usually insulators and any end of live cross arms or poles are addressed at the same time to gain economies of scale. The project is described in more detail within the asset management plan. This area has been identified as a high priority of those remaining in the project.

Risk Identification & Mitigation (5.4.5.2 A.4)

This restricted wire project area is a typical replacement project including replacement of conductor, insulation and other assets such as poles and/or transformers as required. PUC has extensive experience with projects of this nature and through usage of standardized framings, the design and construction should be efficient and straight forward. Project construction may be delayed if unanticipated higher priority unplanned emrgency or customer demand work arises. However, no risks are anticipated which would delay the design or construction of this project significantly.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

PUC has fairly extensive historical information on restricted wire projects and projects of similar nature. Using this information, the length of restricted conductor to be replaced, single phase versus three phase, quantity of poles, quantity of transformers and other unique criteria, PUC is able to reasonably estimate each project without a detailed design being completed beforehand. Variances within project areas may occur that will affect budget, but anticipate that cost variances will even out over the project.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no new REG investments associated with this project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific locations whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

Replacements will be constructed using USF standards, PUC standards and/or specifics approved by a Professional Engineer.

Refer to sketch (2018) 1C300-1-4A for an understanding of the area to be replaced.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

Worker safety is the primary investment driver for this project. As stated in the project summary, the restricted wire can become brittle and break with minimal disturbances. This becomes even more of a concern when PUC and/or third party contractors are working on infrastructure attached to PUC's poles with restricted wire present. Eliminating the restricted wire will eliminate the planned outage times an delay costs associted with making the worksafe safe.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

Economical efficiencies is the secondary driver for this project. PUC's current practice for work on poles containing restricted wire is to take an outage if staff, contractors or joint use telecom parties are working on or below the conductor. By eliminating restricted conductors, PUC reduces the requirements to take outages.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

The investment objectives are to eliminate safety hazards within PUC's electrical distribution system.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

It is common knowledge and well documented across the utility sector that small copper conductors, over time, become brittle and present a safey risk if not adequately manged through costly customer impactive work methods. Most utilities have already eliminated or are in the process of eliminating restricted conductor where it still exists.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project receives a moderate priority, below emergency and system access demands. Due to the nature of the hazard, it is important to continue to remove restricted conductor from service, but working around restricted conductor can be handled through work procedures until all restricted conductor is removed. Not completing this project area in the budget year will cause the project to be extended, resulting in the associated operation and repair costs both stretching out and icreasing over time.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

Completing this project and removing the restricted conductor will have a positive effect on system operation efficiency. Removal of restricted conductor will minimize failures leading to a more efficient, higher reliability system. During the removal of restricted conductors, associated infrastructure (insulators, poles, transformers, etc.) are reviewed and addressed if required.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers benefit from a safer, more reliable system and more cost effective electrical distribution system.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

Through the removal of restricted conductor and replacement associated infrastructure beyond it's useful life will provide a more reliable system, reducing the frequency of outages.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

There are no practical alternatives available for this project area and project as a whole.

Safety (5.4.5.2 B2)

Safety is a primary driver of this project. Removal of restricted conductor eliminates the costs and customer inconveniences associate with routinely isolating circuits to provide adequte worker safety.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

This project has no adverse impact on cyber security or privacy issues.

Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers (where applicable)

Project will be constructed to USF and/or PUC specific standards which are in line with industry standards allowing third parties reasonable access. Where third party providers are currently attached to poles, coordination will occur during design phase.

Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements (where applicable)

Infrastructure replacements are typically constructed to USF and/or PUC standards, which are based on meeting the current and future customer needs and distributing electricity reliably, safely and cost effectively.

Economic Development (5.4.5.2 B.5) (where applicable)

Reducing downtime of PUC's system contributes positively towards economic development in the region.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

PUC considers environmental impacts when replacing infrastructure. Construction techniques are considered to minimize effects on the environment.

C. Category-Specific Requirements - System Renewal

Asset Performance-related operational targets & asset lifecycle optimization policies and practices (refer to 5.2.3 & 5.3.3) (5.4.5.2 SR-C1.1)

This project receives a moderate priority in relation to PUC's system renewal projects, after emergency forced renewal. This prioritization is based upon the safety aspect in conjunction with the reliability concern compared to other projects. Additionally, each project area within the project is reviewed and prioritized compared to one another. Aspects considered are, but not limited to, residential versus rural, vegetation, pedestrian traffic, nearby protective devices. The higher the risk, the higher the priority of the project becomes.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR-C1.2)

The typical age of installation in areas where restricted wire is present is typically mid 1970's or earlier. This results in assets being a minimum 40 years or older. This is generally why restricted wire projects involve more than simply replacing the conductor. Replacing the conductor only, would not be an efficient long term solution and would not bring the value of economies of scale.

The number of customers in each class potential affected by failure of the assets (5.4.5.2 SR-C1.3)

Number of Residential Customers: 12
Load Impacted (Tx Ratings): 137.5kVA

Quantitative customer impacts (5.4.5.2 SR-C1.4)

It is not feasible to determine quantitative customer impacts for this project ahead of time.

Qualitative customer impacts (5.4.5.2 SR-C1.5)

Customers in the area of this project will benefit from an improved system, higher level of safety and a more reliable electrical distribution system.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have bearing on the criticality and/or cost of failure (5.4.5.2 SR

Impacts to customers can vary on a customer by customer basis. Failure of system to a residential customer will have different impacts depending on the season and if the customer's residence is heated via electric heat or not. If the customer is a commercial customer, outages during regular business hours can impact revenue and therefore an increased cost to the customer. This project will improve system reliability, reduce outage durations and in turn be less impactive to customers.

Timing and Priority of Project (5.4.5.2 SR-C2)

This project generally receives a moderate priority in relation to PUC's system renewal projects. The project is a front lot project fully accessible from the road. Due to the extensive ditches in the rural areas well as the lack of snow storage in the area, this project is preferred to be completed in the non-winter months.

Consequences for system O&M costs (5.4.5.2 SR-C3)

The project will remove restricted wire and generally replace it with new primary conductor causing a negligible difference in overall system length. Investment in capital through the replacement of aged poles and associated infrastructure is a positive factor with respect to long term operating costs.

Impact on reliability performance and/or safety (5.4.5.2 SR-C4)

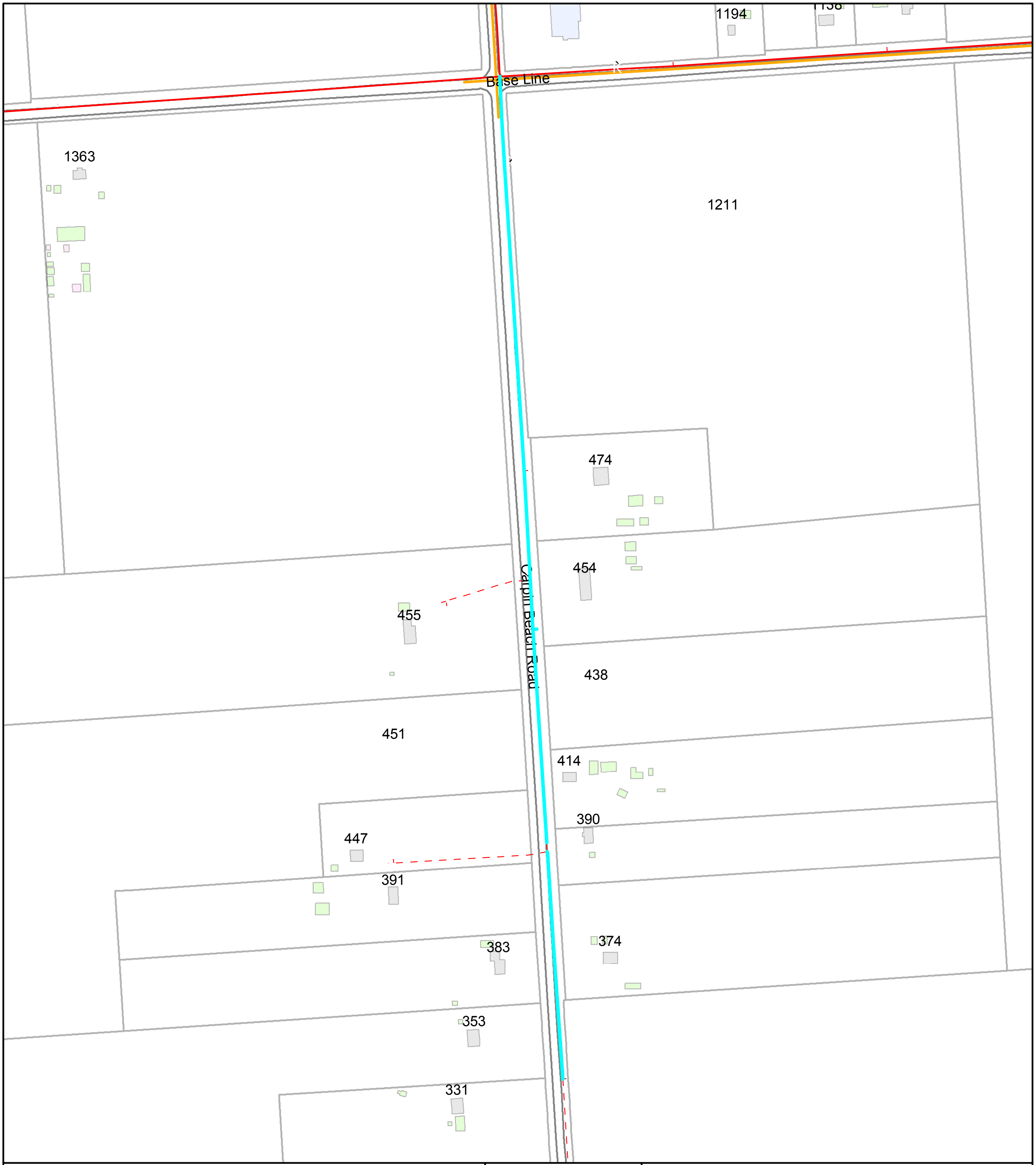
As described above, this project will have a positive impact on worker safety, eliminating the need to put barriers in place and inconvenience customers through outages when working on the distribution system.

Analysis of Project Benefits and Timing (5.4.5.2 SR-C5)

This project generally receives a moderate priority in relation to PUC's system renewal projects. Project timing is considered to optimize all project construction schedules considering access, seasons and customer impacts.

Like for Like Renewal Analysis, Alternatives Comparison (like for like vs. not like for like, timing, rate of replacements, etc.) (5.4.5.2 SR-C6)

While like-for-like replacements may be a possibility, reviewing the distribution system as a whole, replacing and reframing infrastructure will provide the most long term benefit to the system and in turn, the customers. Alternatives to replacing restricted conductor are not available.



Notes:
All locations are approximate as final design has yet to be completed.

SCALE: NTS

SYSTEM PLANNING
2018 - RESTRICTED WIRE
CARPIN BEACH RD
BASE LINE TO HERKIMER ST.
PHASE 1 OF 2

REV #	REVISION	DATE	INITIAL
A	FOR INFORMATION ONLY	SEP 08/17	JT

DRAWN BY: J. TEVC	DATE: SEP. 08/17
CHECKED BY:	DATE:
APPROVED BY:	DATE:

DRAWING No.:	**REV**
(2018)-1C300-1-4A	**A**

Appendix H

Customer Engagement

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.

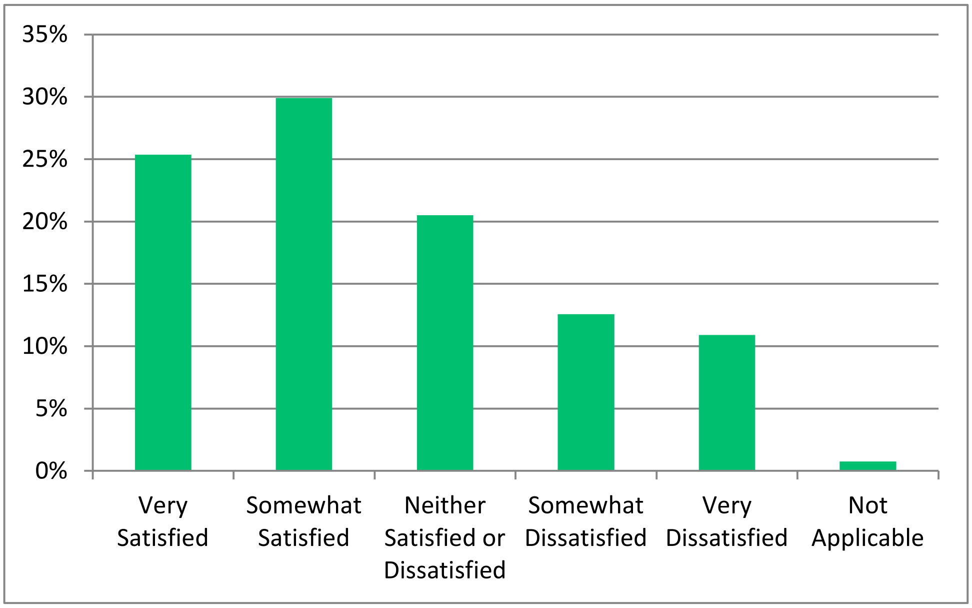
Customer Engagement Survey - DEMOGRAPHICS & SEGMENTATION

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.

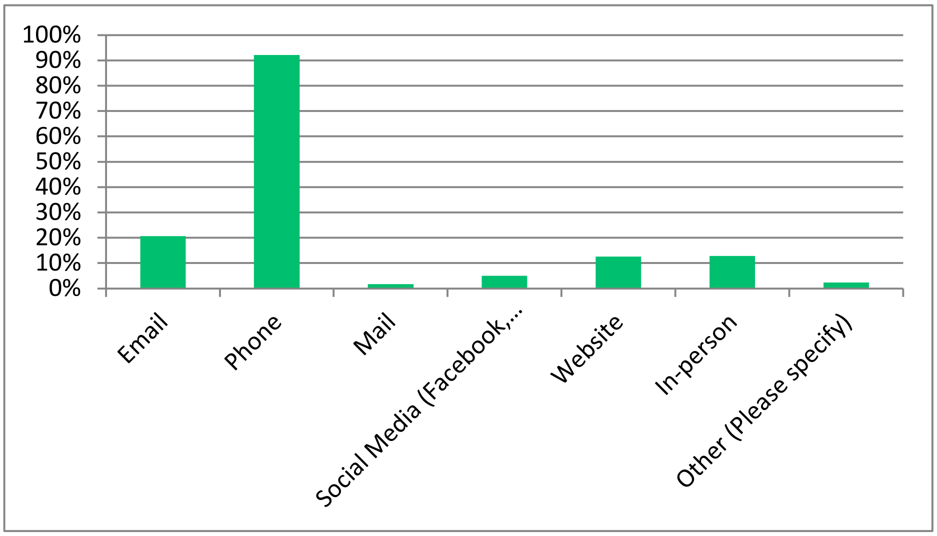
Customer Engagement Survey - PUC PRIORITIES

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

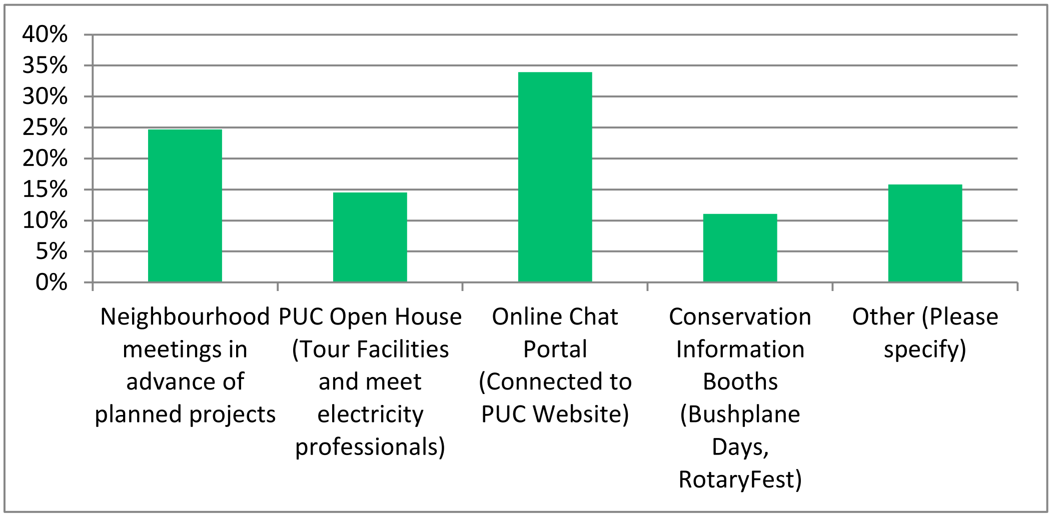


Question 14

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.

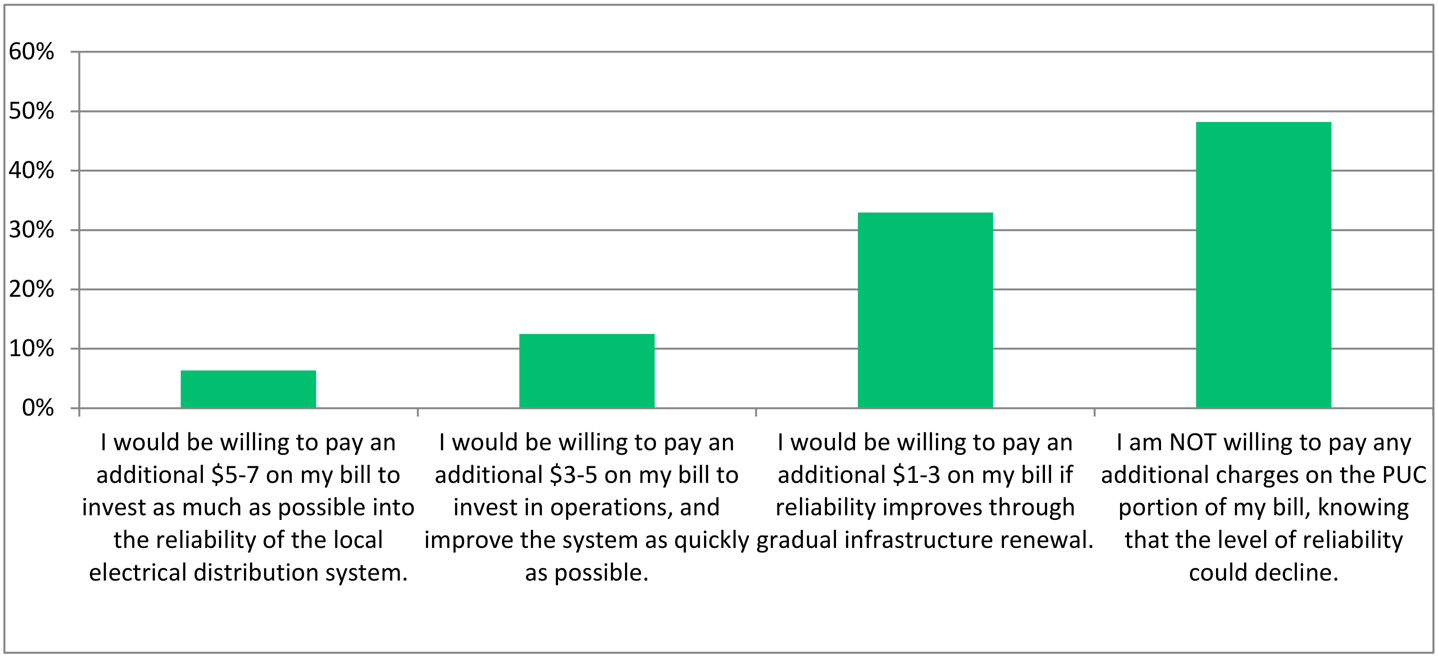
Customer Engagement Survey - OPERATIONS, MAINTENANCE & ADMINISTRATION

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.



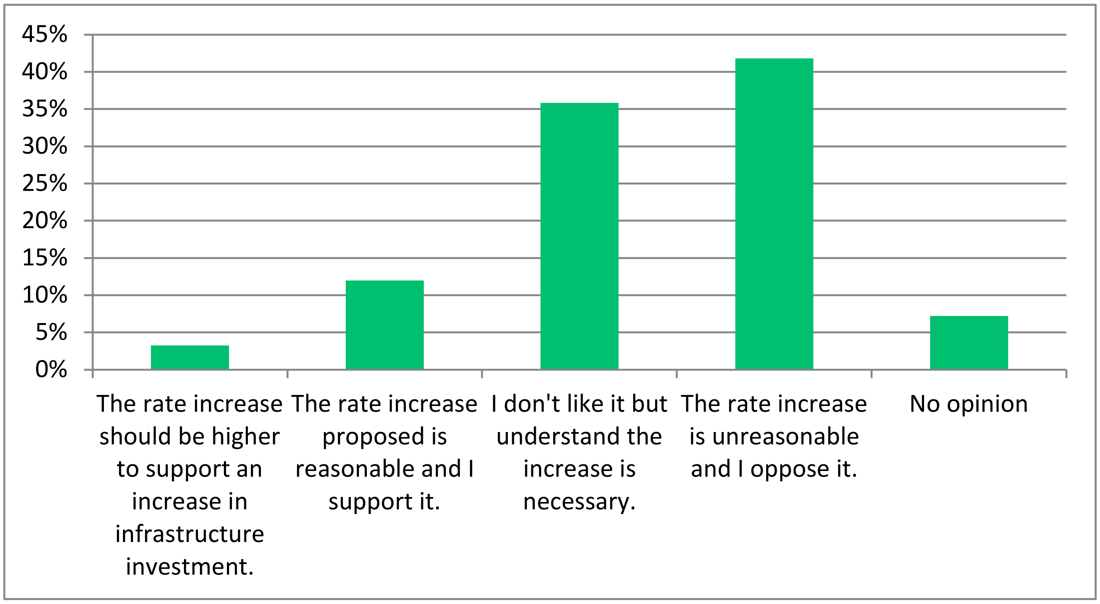
Question 22

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.

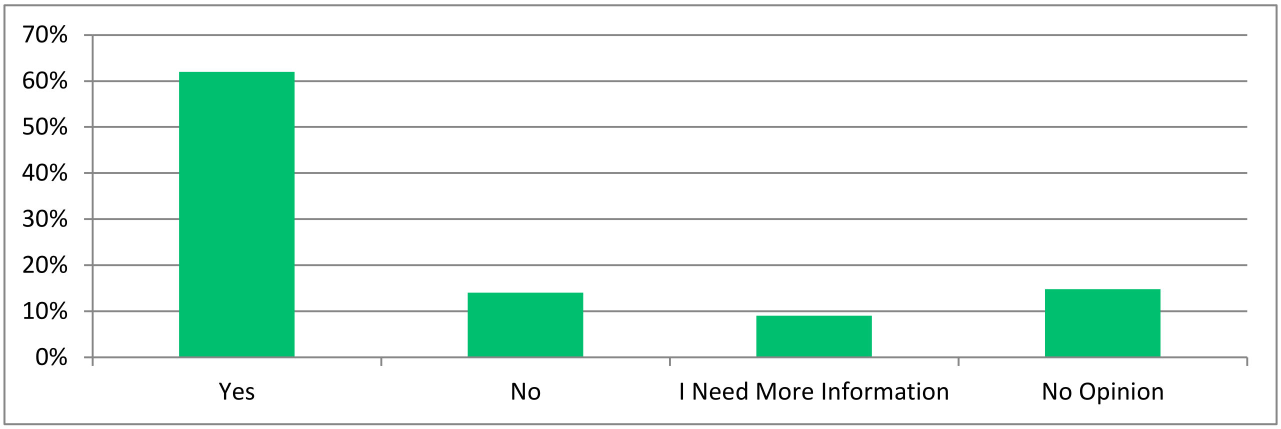
<u>Customer Engagement Survey - PROPOSED INCREASE</u>

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.

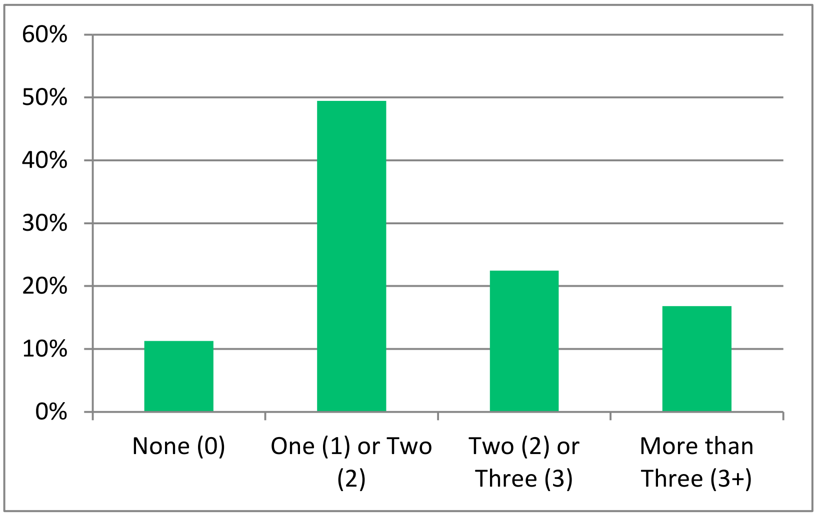
Most participants did state that they were provided with enough information in the survey to understand the reasons behind the proposed rate increase. This supports the previous question of customers understanding the rate increase is necessary, but not liking it or supporting it, based on the information 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)*

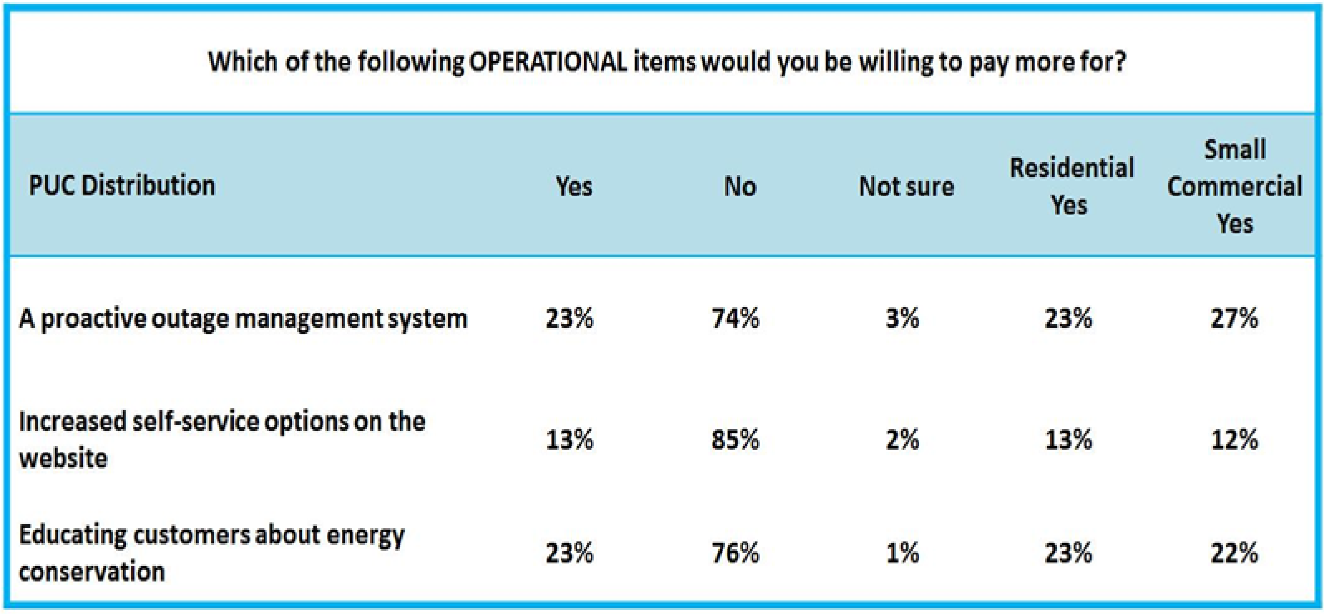
- 54% increased tree trimming
- 46% a proactive outage management system
- 46% educating customers and the public about electricity safety
- 45% educating customers about energy conservation

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 **<u>capital</u>** items they were willing to pay more for: *(pg. 41 - 2017 UtilityPULSE CS Survey Results*)

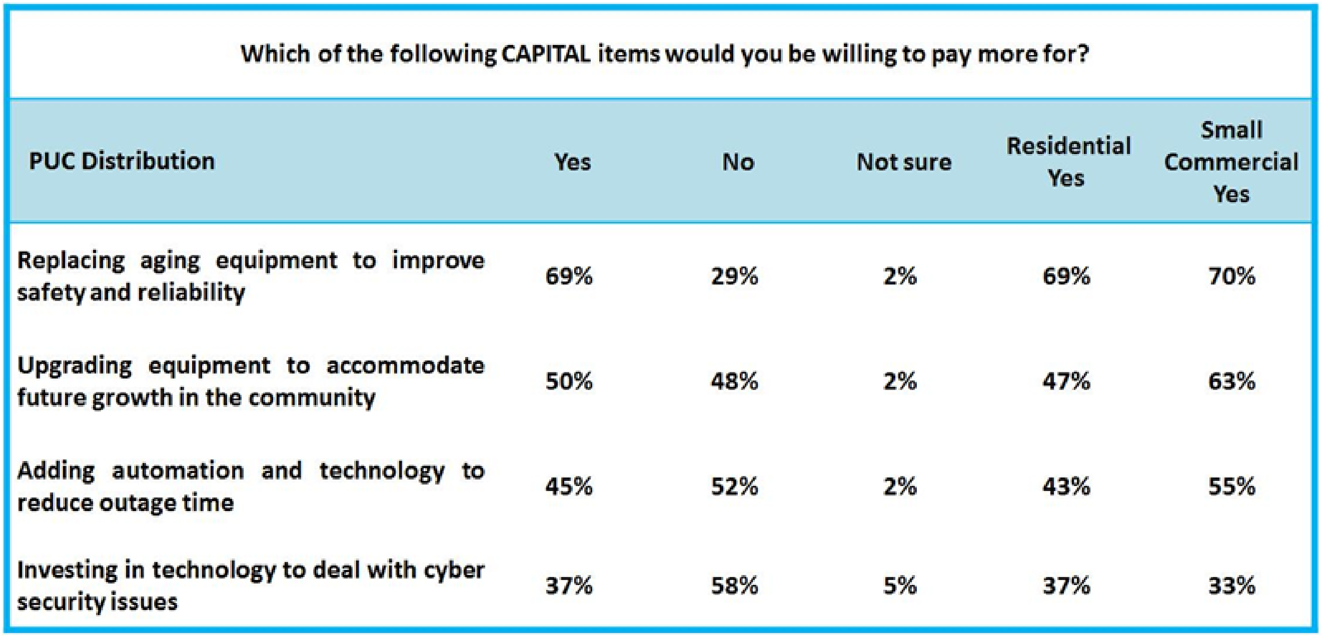
- 69% replacing aging equipment to improve safety and reliability
  - Of those who answered YES = Residential 69% / Small Commercial 70%
- 50% upgrading equipment to accommodate future growth in the community
  - Of those who answered YES = Residential 47% / Small Commercial 63%



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%

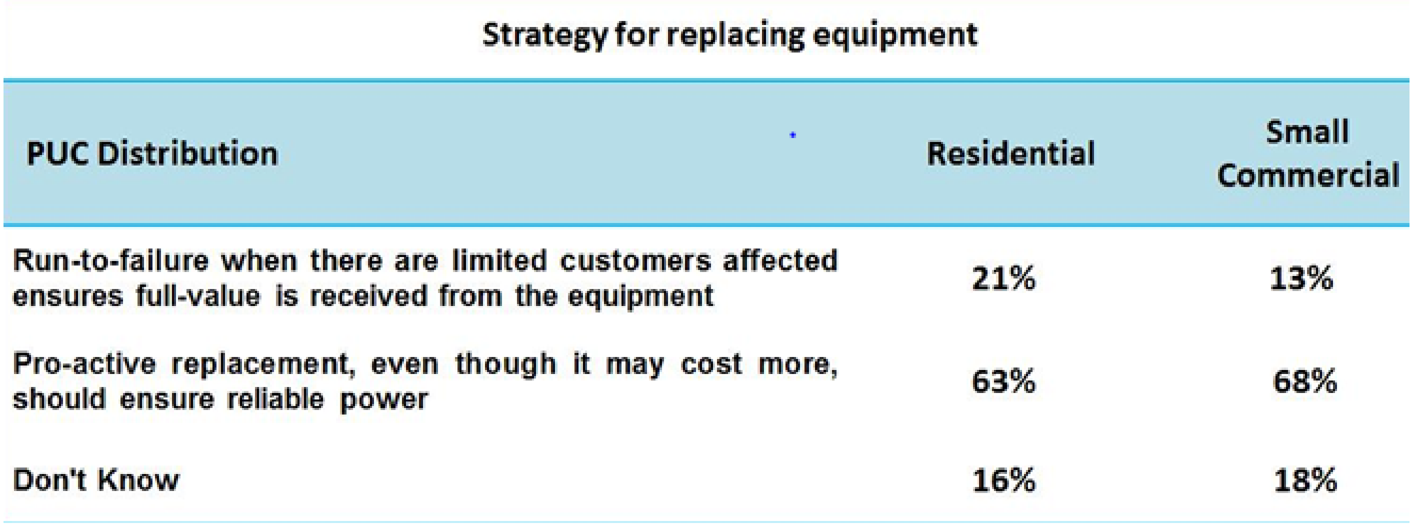
(pg. 44 – PUC Distribution Inc. 2017 UtilityPULSE Customer Satisfaction Survey)



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%

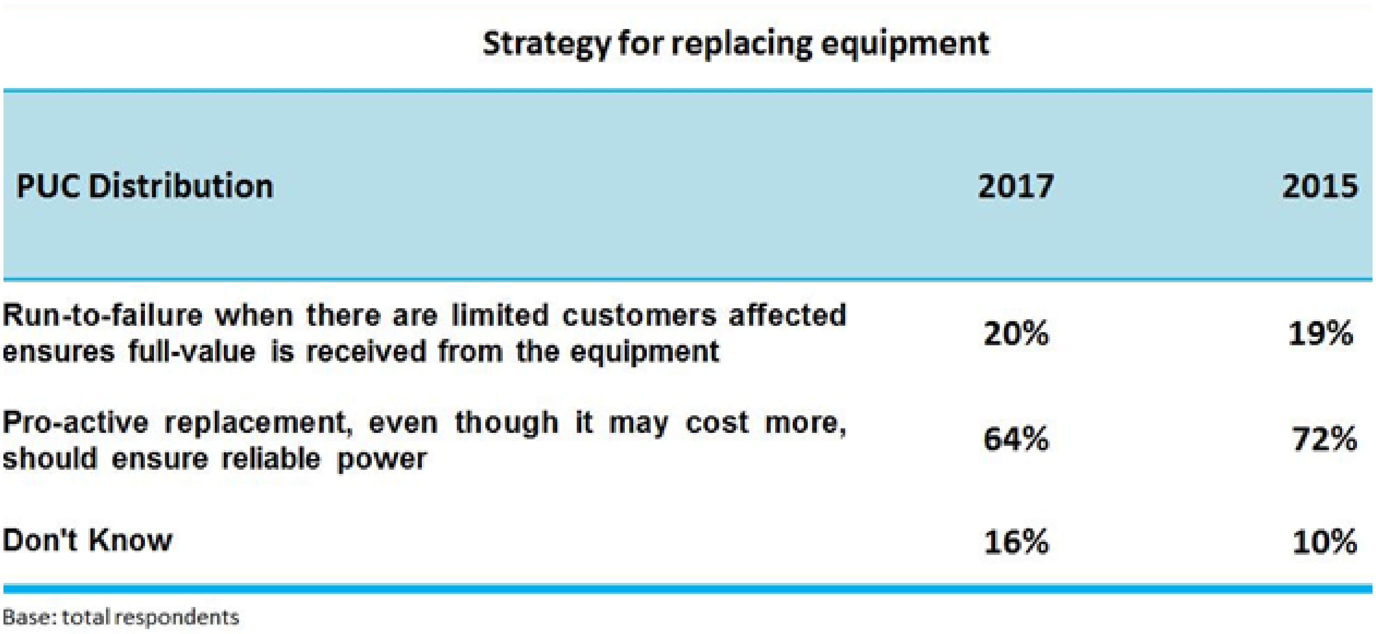
(pg. 41 – PUC Distribution Inc. 2017 UtilityPULSE Customer Satisfaction Survey)



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.”

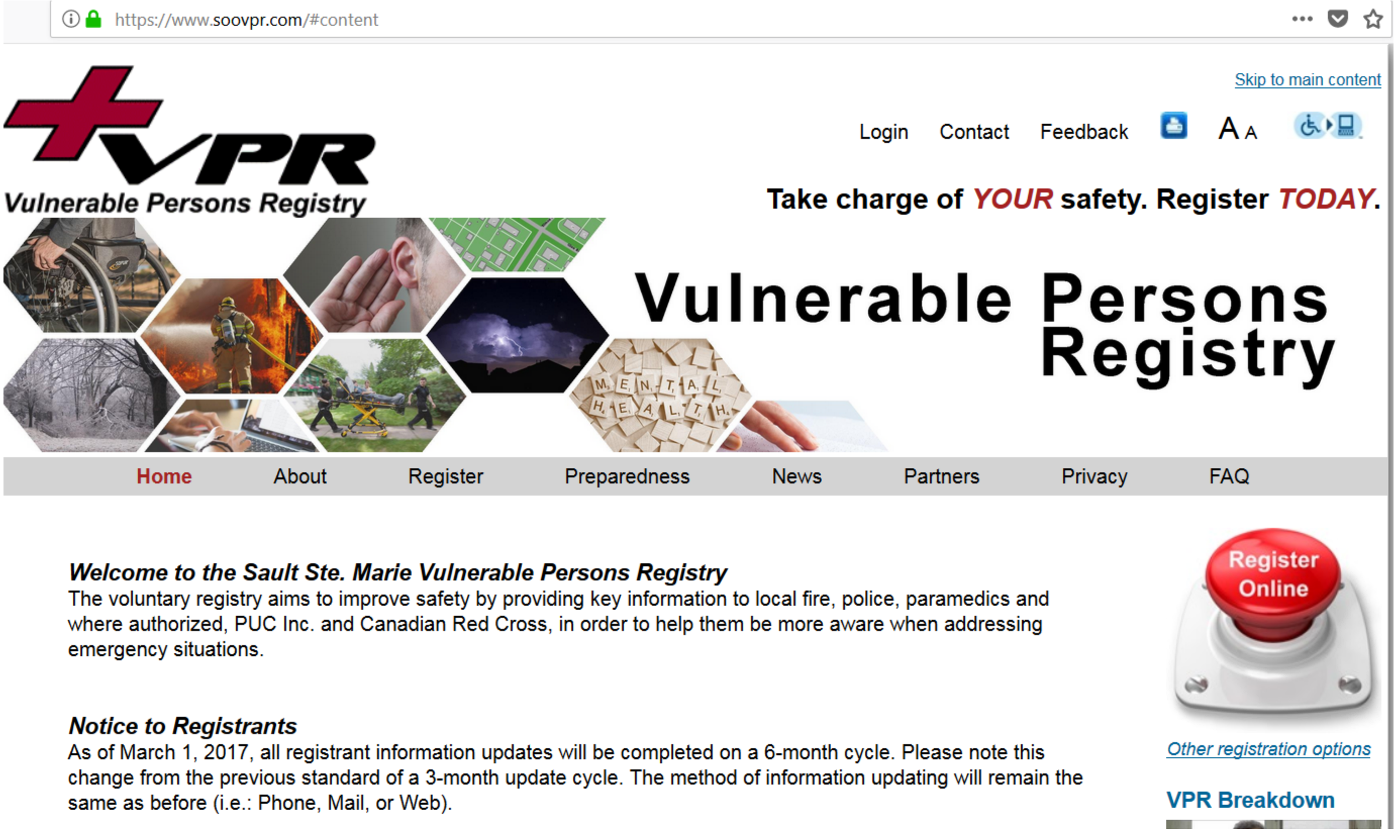
iii. While improvements were made to the emergency, unplanned outage notification system, customers expressed the desire for improvements to be made in PUC's planned outage notification process. PUC addressed these concerns by developing the Atlas Notification System. Implementing this new system required 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



Welcome to the Sault Ste. Marie Vulnerable Persons Registry

The voluntary registry aims to improve safety by providing key information to local fire, police, paramedics and where authorized, PUC Inc. and Canadian Red Cross, in order to help them be more aware when addressing emergency situations.

Notice to Registrants

As of March 1, 2017, all registrant information updates will be completed on a 6-month cycle. Please note this change from the previous standard of a 3-month update cycle. The method of information updating will remain the same as before (i.e.: Phone, Mail, or Web).

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

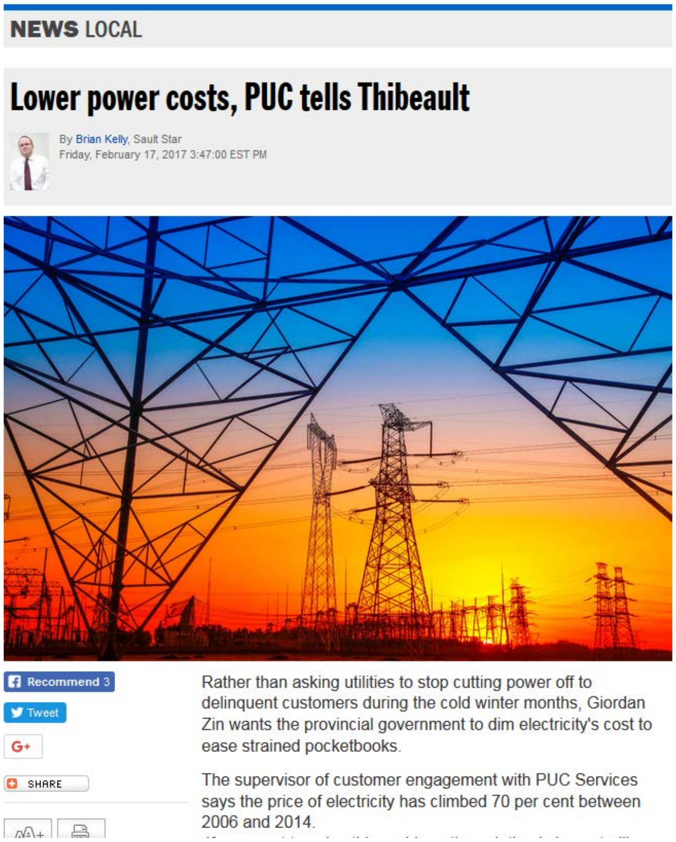
The introduction of Social Media accounts such as Facebook, in 2013 and Twitter in 2012 allowed PUC to communicate with a larger online audience and reach different target markets with messages about; worker safety, electrical shock and safety, home renovation/upgrades, energy-efficient products, electricity 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

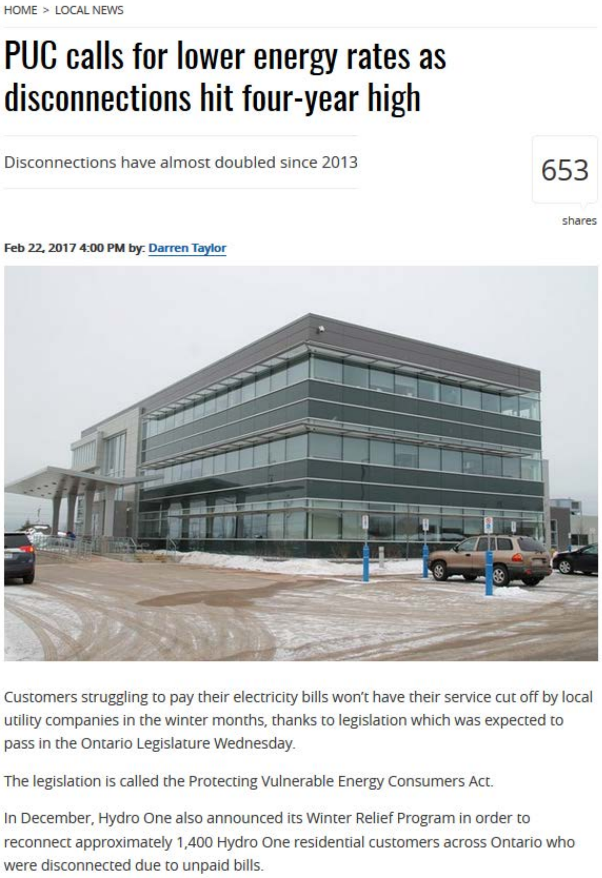
Lower power costs, PUC tells Thibeault

By Brian Kelly, Sault Star
Friday, February 17, 2017 3:47:00 EST PM

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

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.

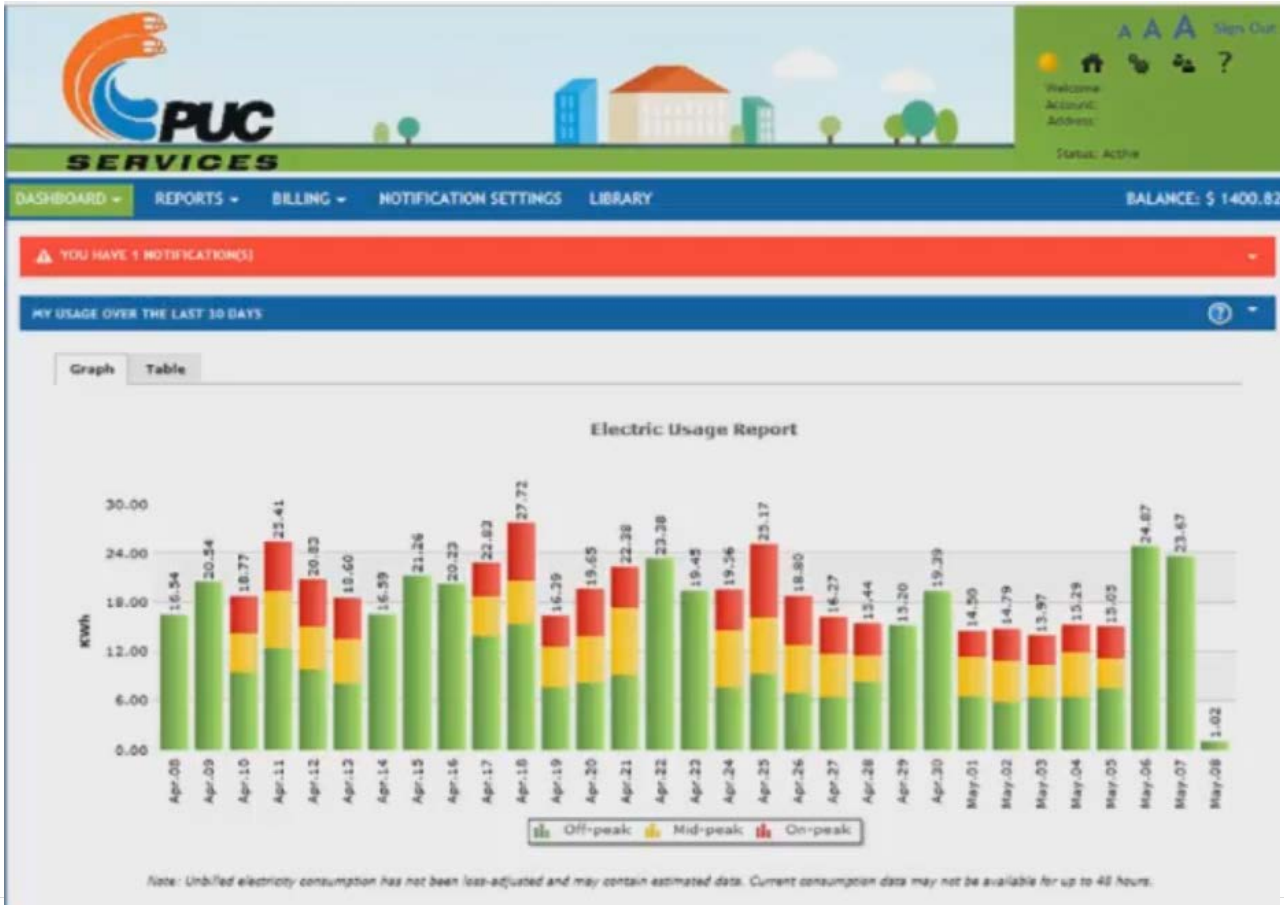
Our commitment to customer care goes beyond the Customer Care department; it involves the entire organization and includes our core value of responsiveness to our community. We are fortunate enough to have a local office where a customer can speak to an engineer about a technical question, a billing 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.



Note: Unbilled electricity consumption has not been loss-adjusted and may contain estimated data. Current consumption data may not be available for up to 48 hours.

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

EXHIBIT 2 – COST OF SERVICE SURVEY STORYBOARD

INTRODUCTION - VIDEO 1

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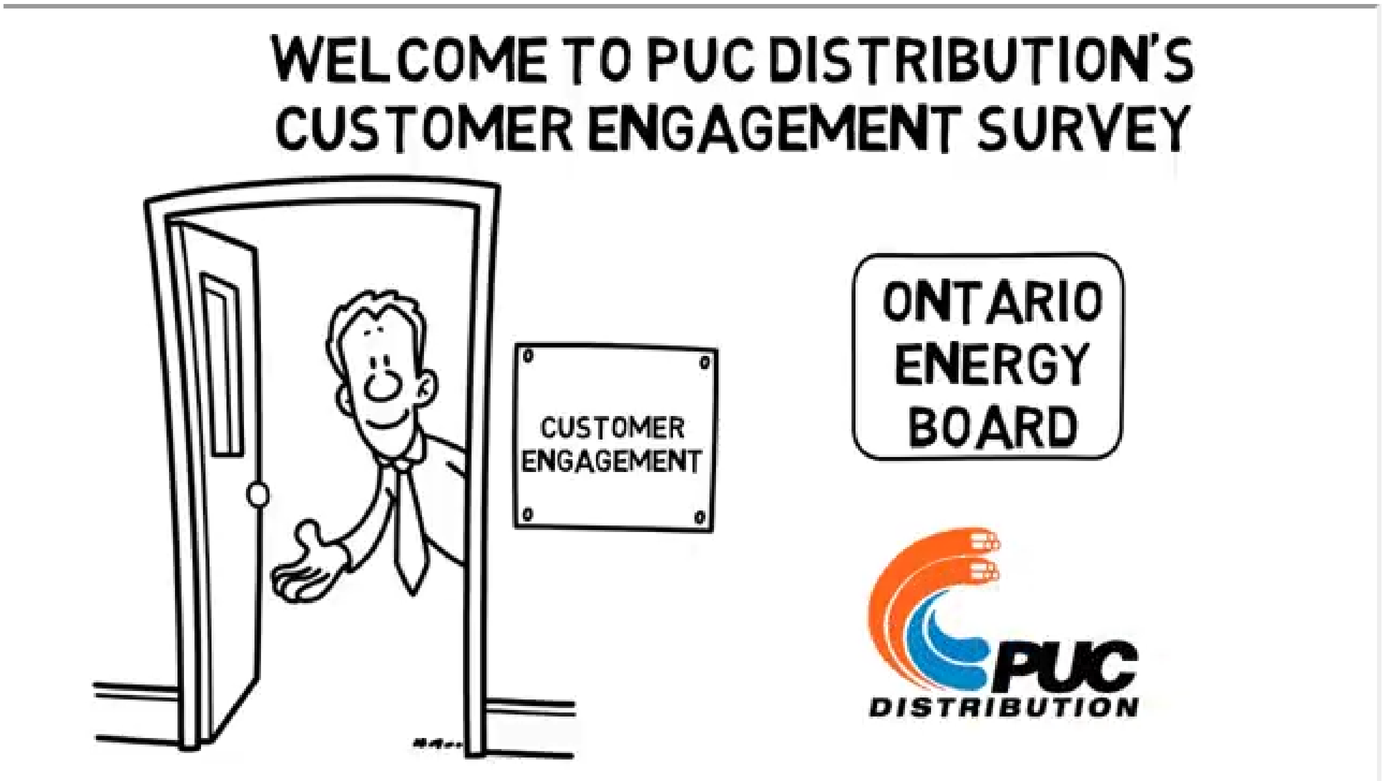

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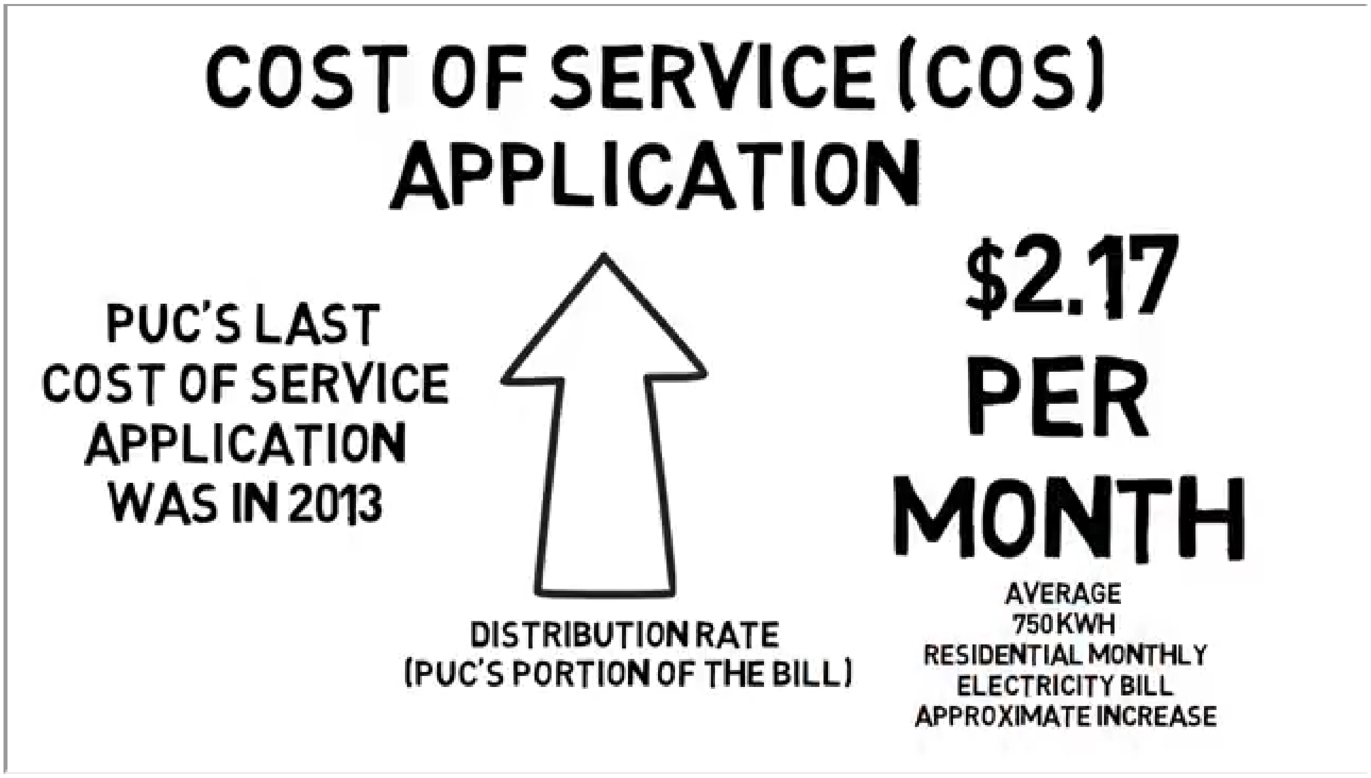
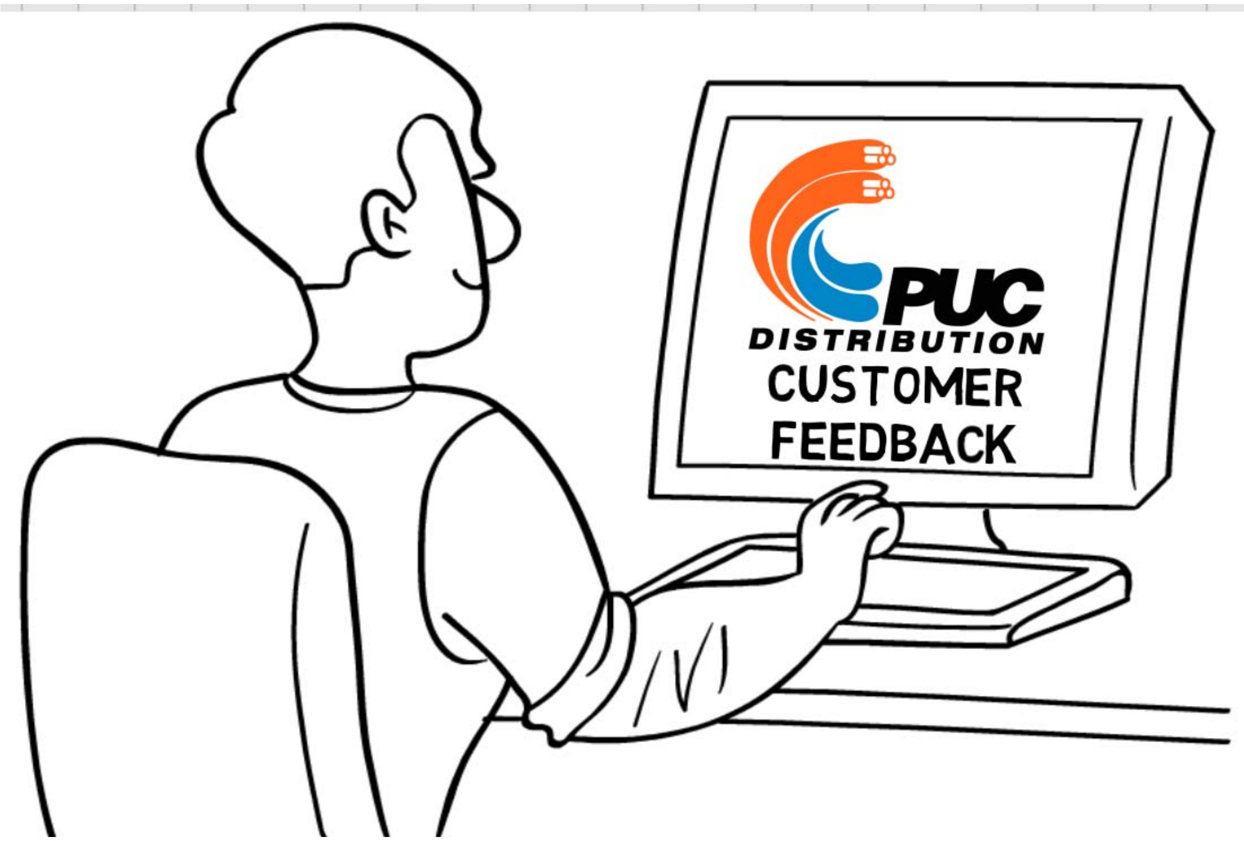


This short survey will guide you through our Cost of Service Application, and more importantly, get your feedback on it.



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YOUR ELECTRICITY BILL - VIDEO 2

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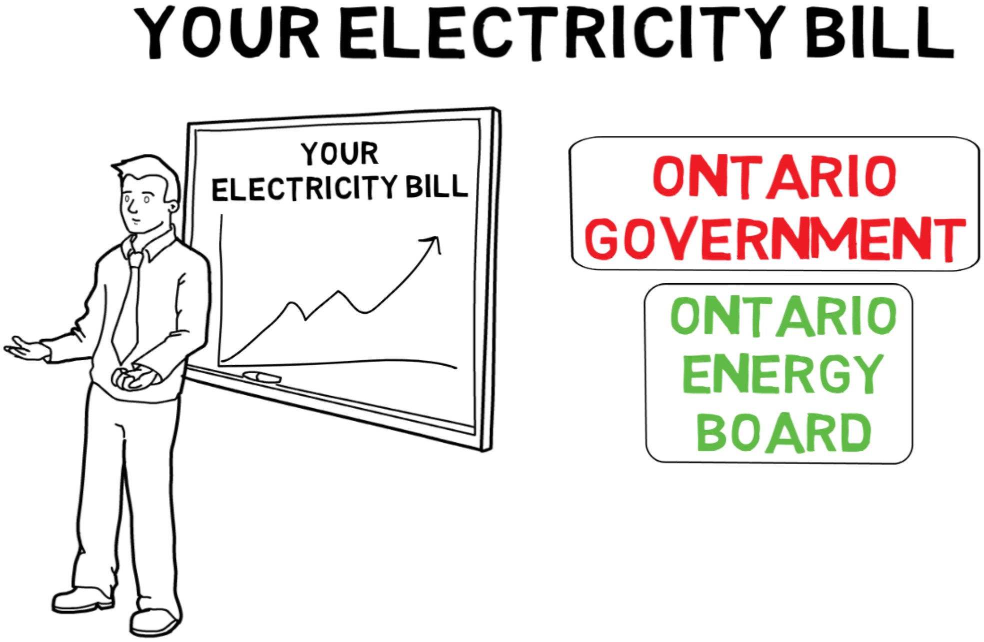

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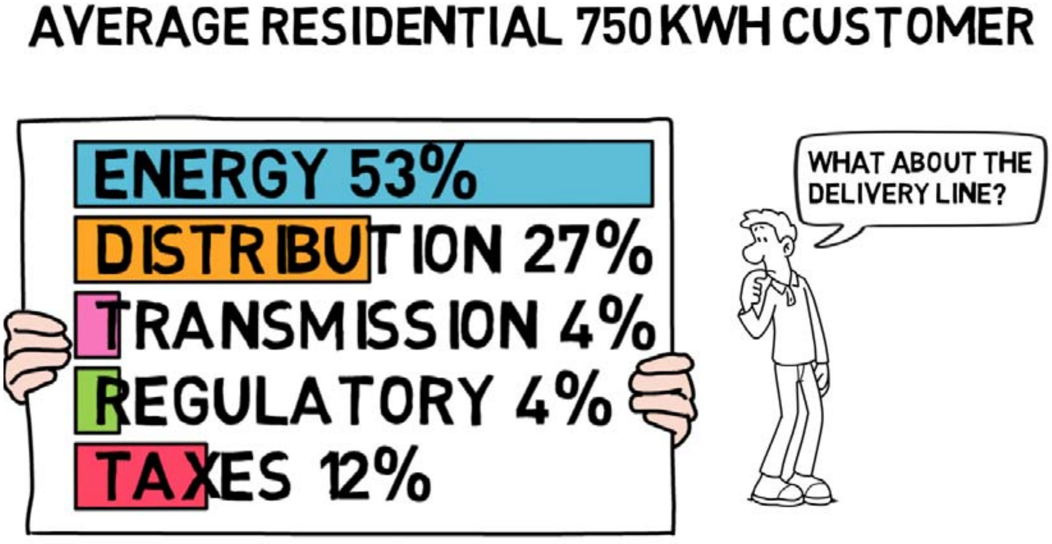
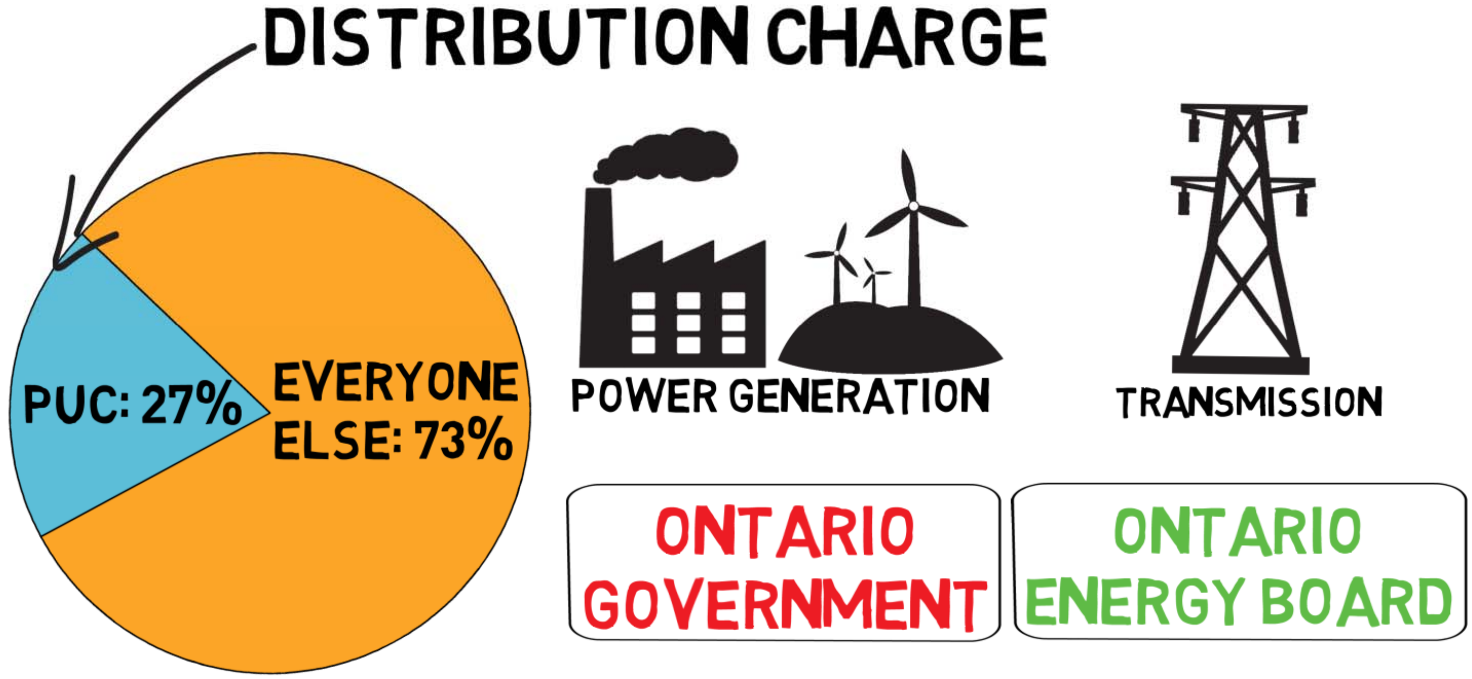
Distribution = 27% of the bill. This is PUC's portion; it covers the costs of the poles, wires and transformers that are used to deliver electricity. Transmission, which = 4%. This covers the cost of transmitting high voltage electricity from generation sites across the province, to our community. PUC 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%.

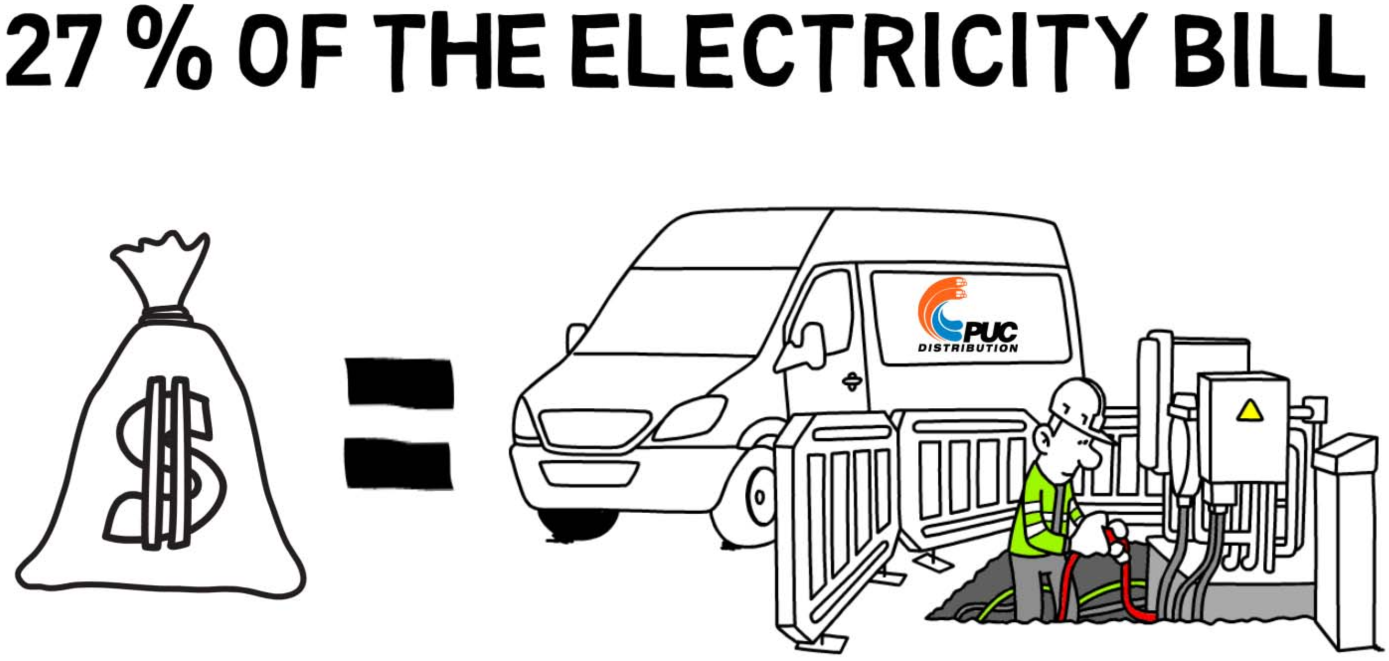
You'll notice that the delivery line from your bill isn't on this chart, that's because the delivery charge is made up of both the distribution and transmission fees .



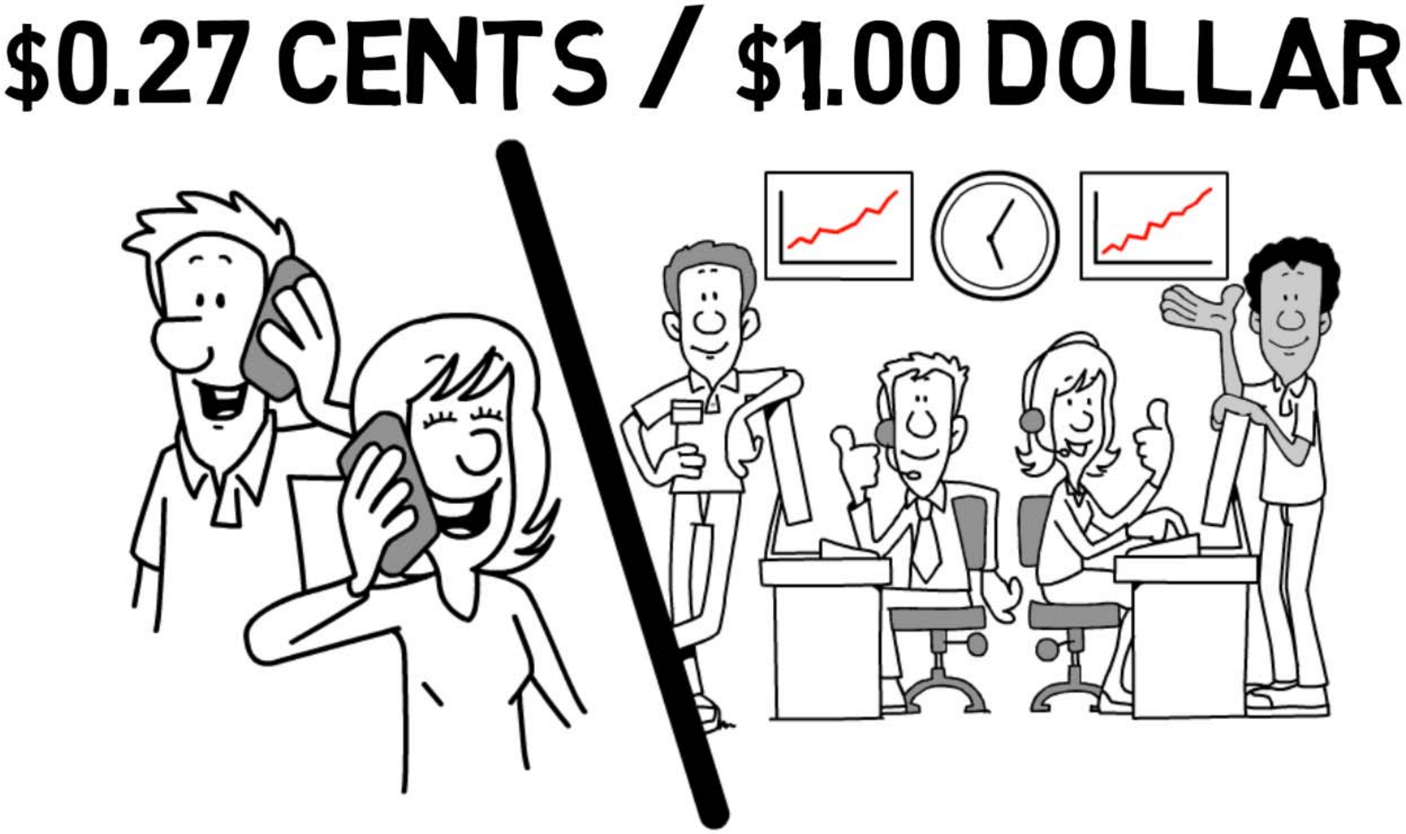
As you can see, PUC's portion (or the distribution charge) is only about 27% of the total bill. This charge is the ONLY fee that PUC has any control over and the ONLY charge we keep - the remaining 73% of the bill is passed on to power generation companies, transmission companies, the provincial government 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.

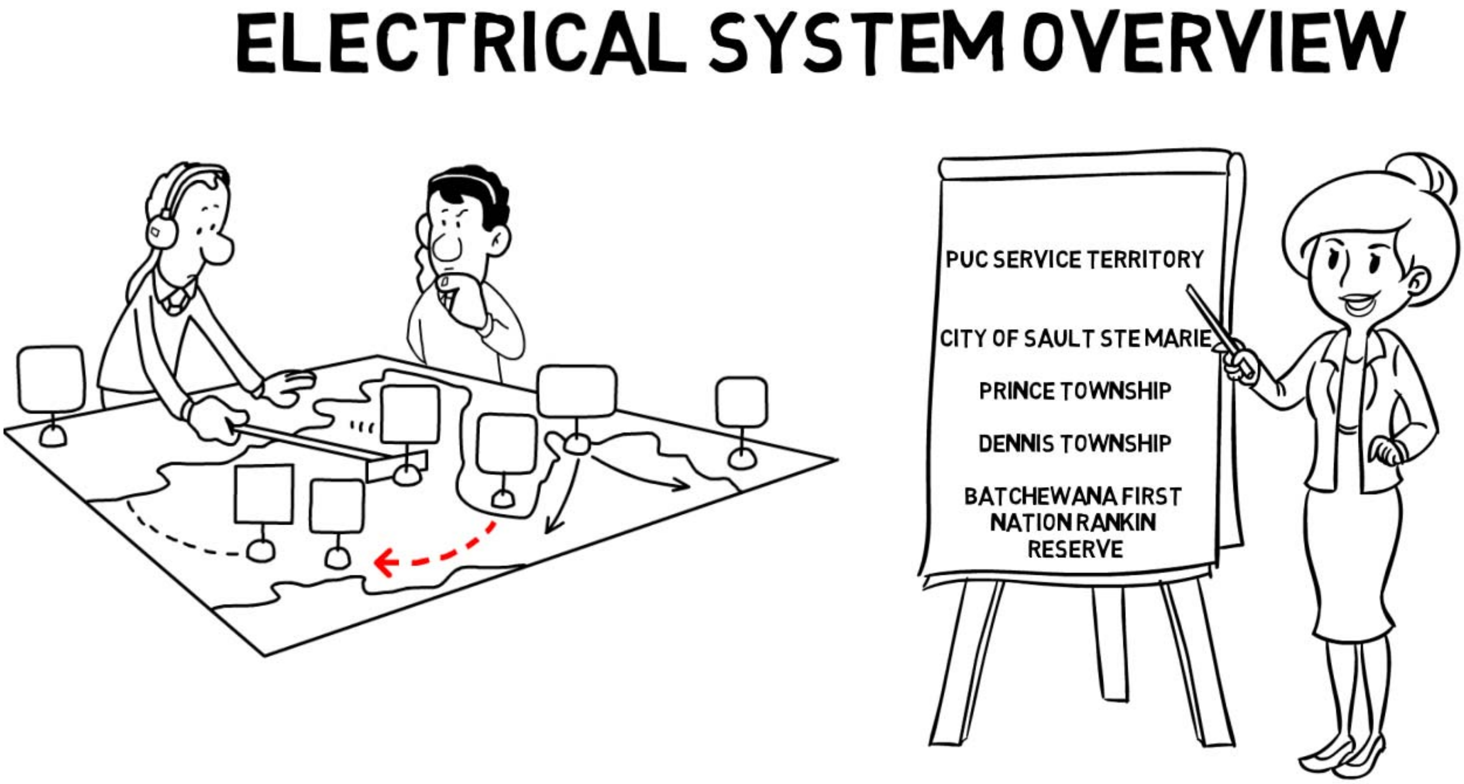


To help put this in perspective; 27¢ from every dollar on the electricity bill covers the entire cost of operating PUC's electric utility.



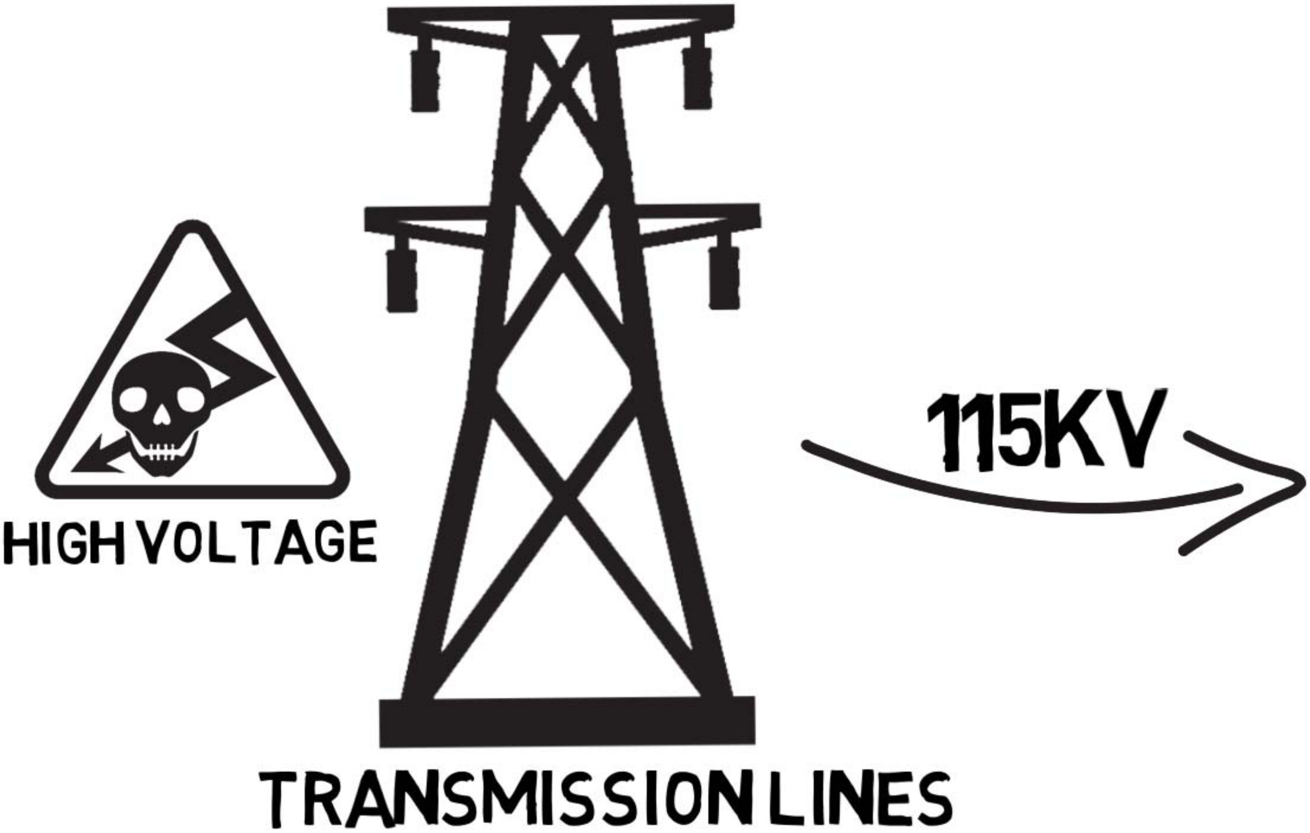
ELECTRICAL DISTRIBUTION OVERVIEW - VIDEO 3

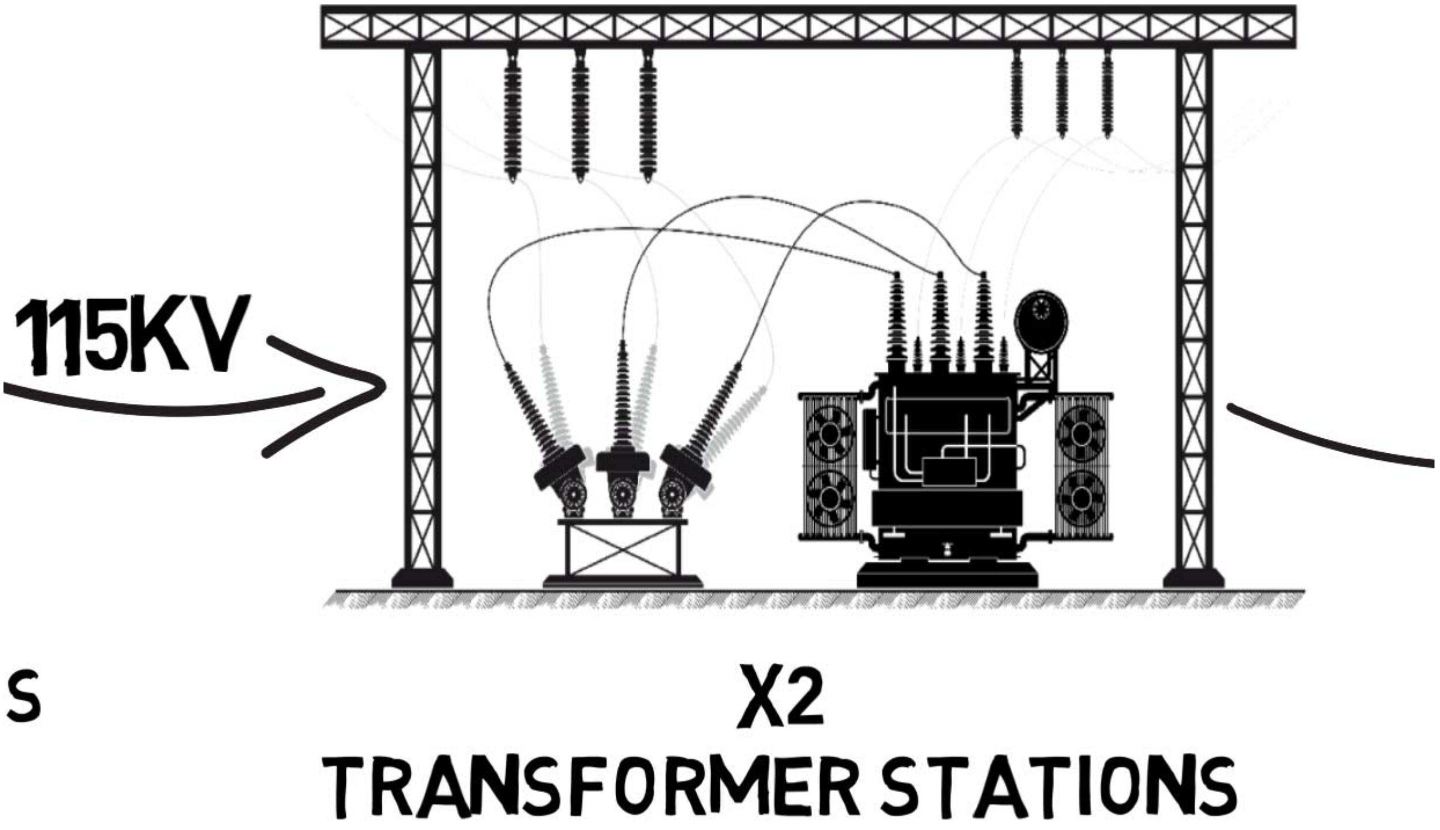
Did you know that PUC Distribution's service territory includes more than just the City of Sault Ste. Marie? It actually extends to parts of Prince and Dennis Townships and the Batchewana First Nation Rankin Reserve.



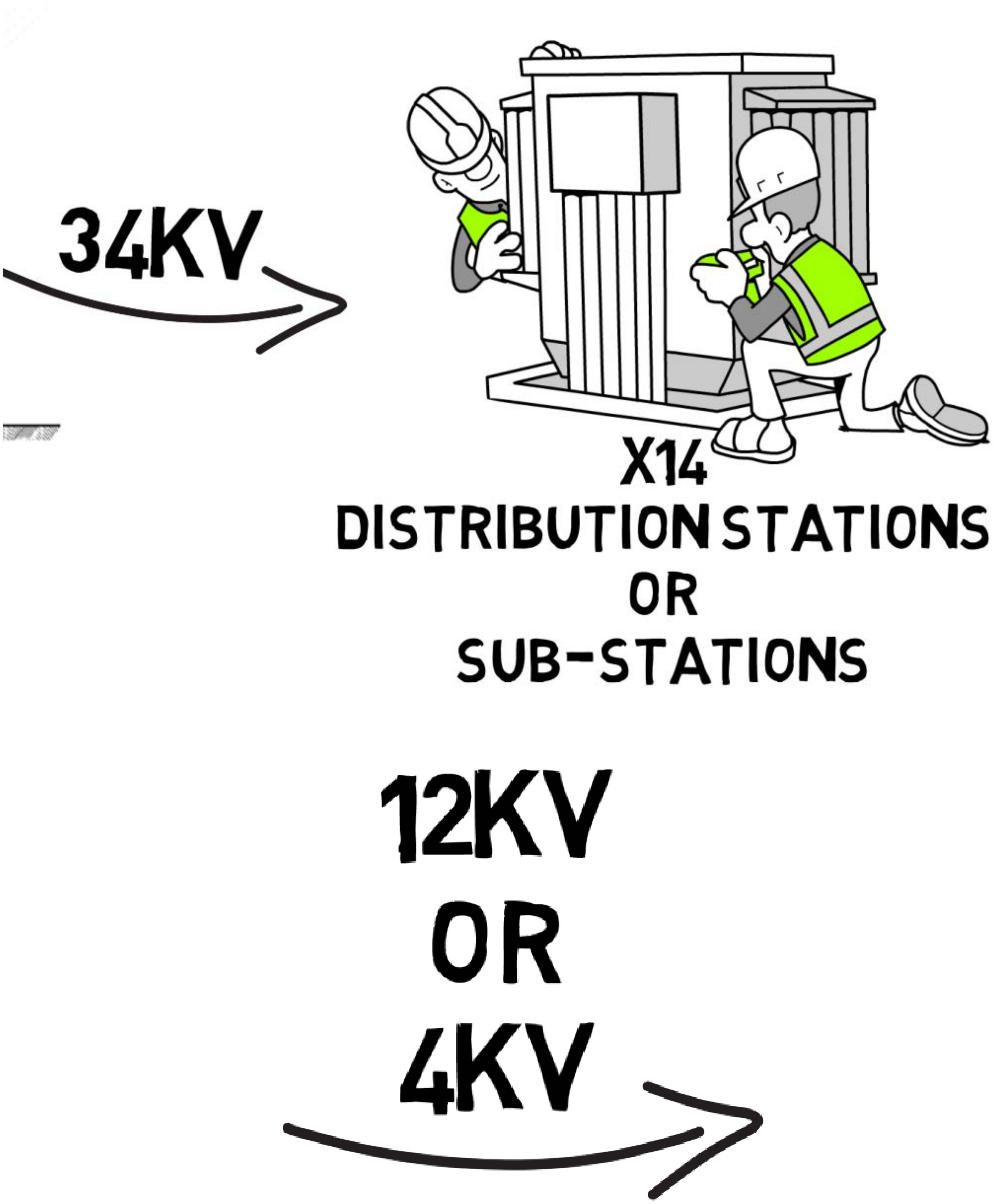
Before we get into what we need the rate increase for, let's talk about how electricity is delivered across PUC's service territory to your home or business.

We receive power from the provincial transmission grid at 115 thousand volts, which supply our two transformer stations.

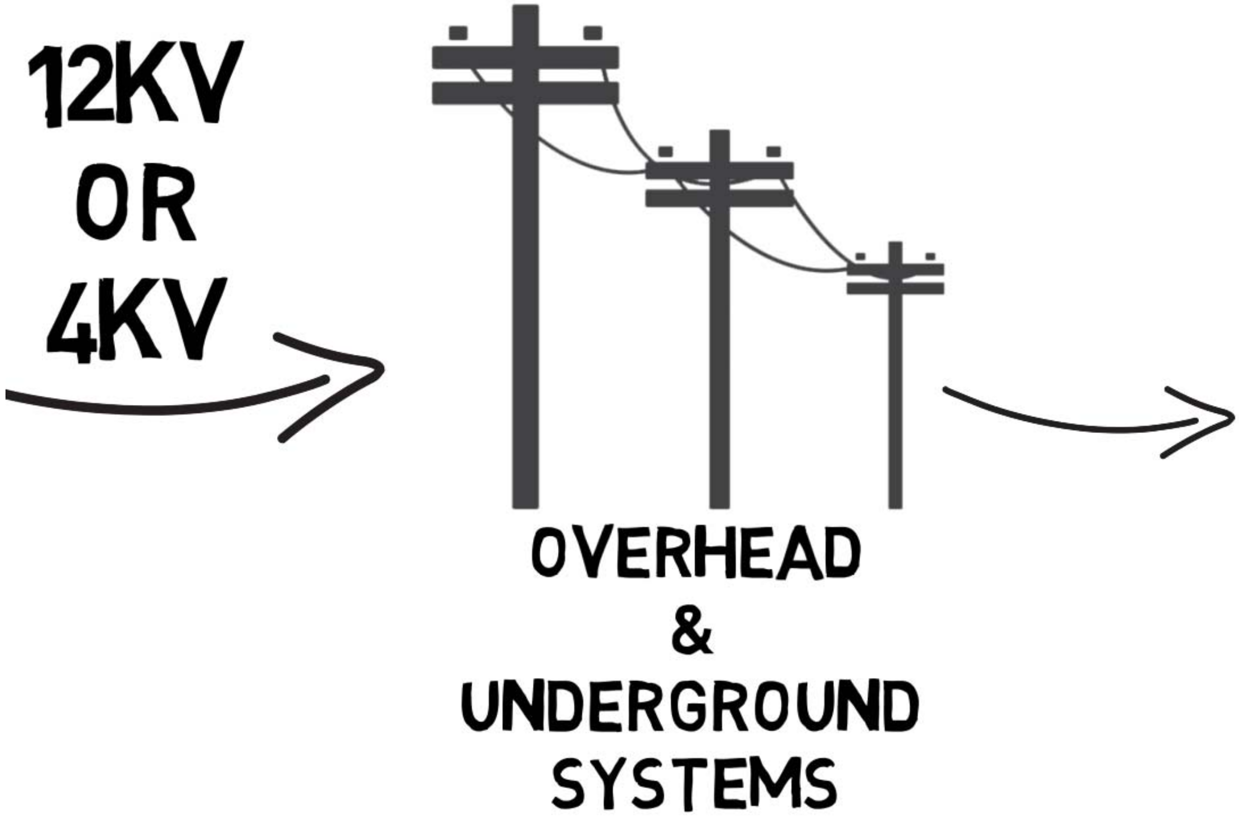




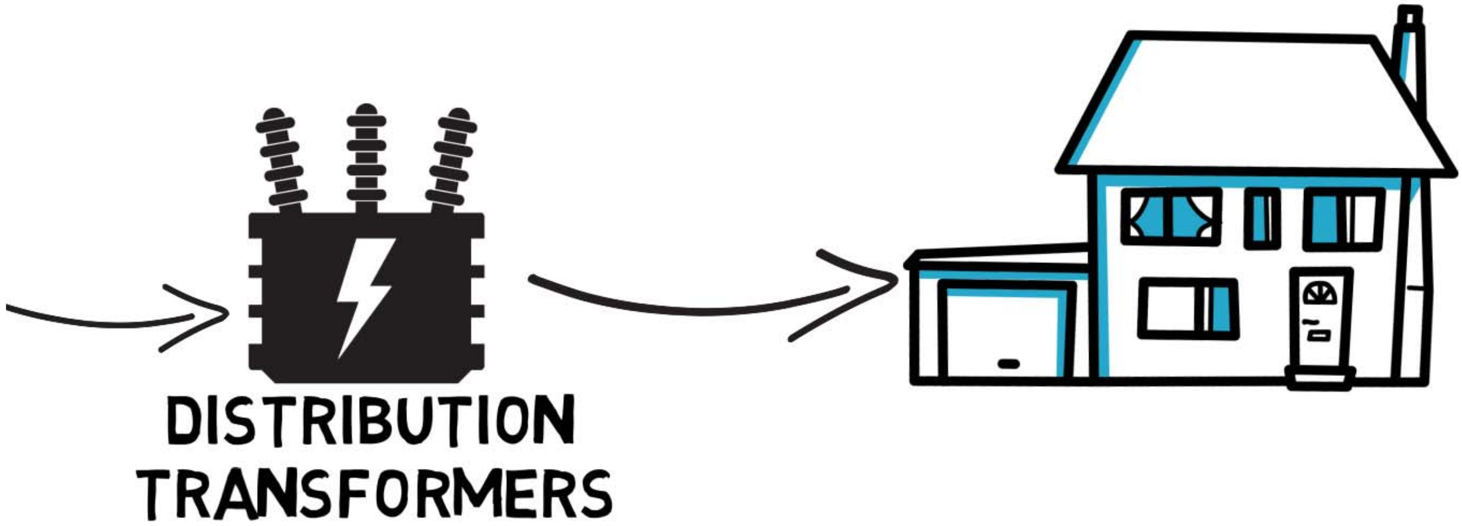
Here we step-down the voltage to 34 thousand volts and transmit it to 14 neighbourhood distribution stations or substations. These substations further reduce power to 12 thousand volts or in some cases, 4 thousand volts.



Power is then delivered to neighbourhoods through overhead or underground wires along the streets and roadways.

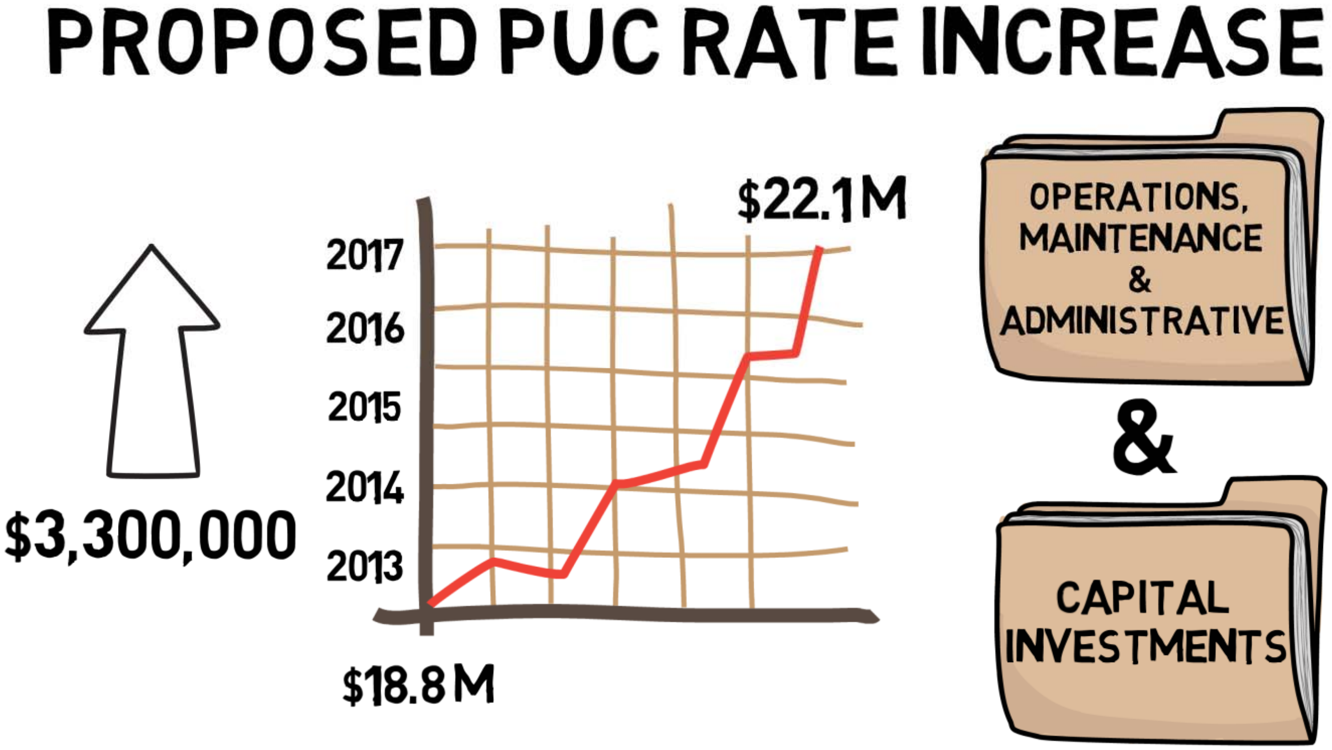


The last step in the journey is the individual distribution transformers that lower the voltage one more time, before the electricity is used by you, the customer.

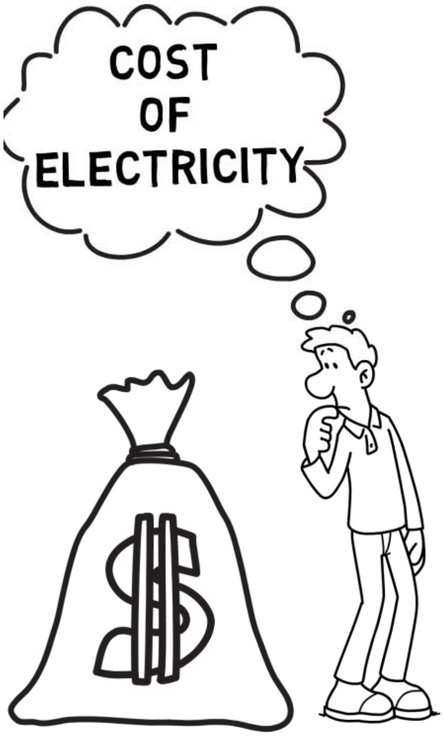


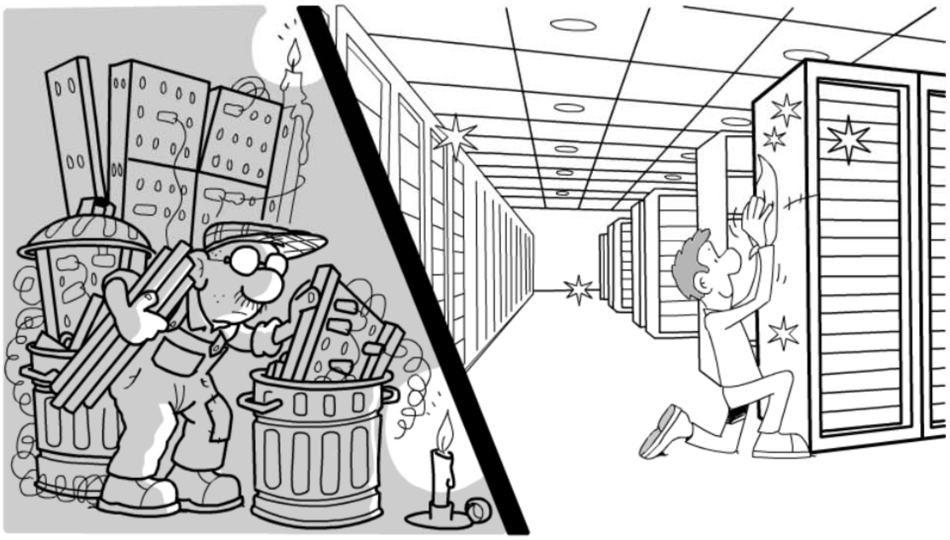
PROPOSED RATE INCREASE - VIDEO 4

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.

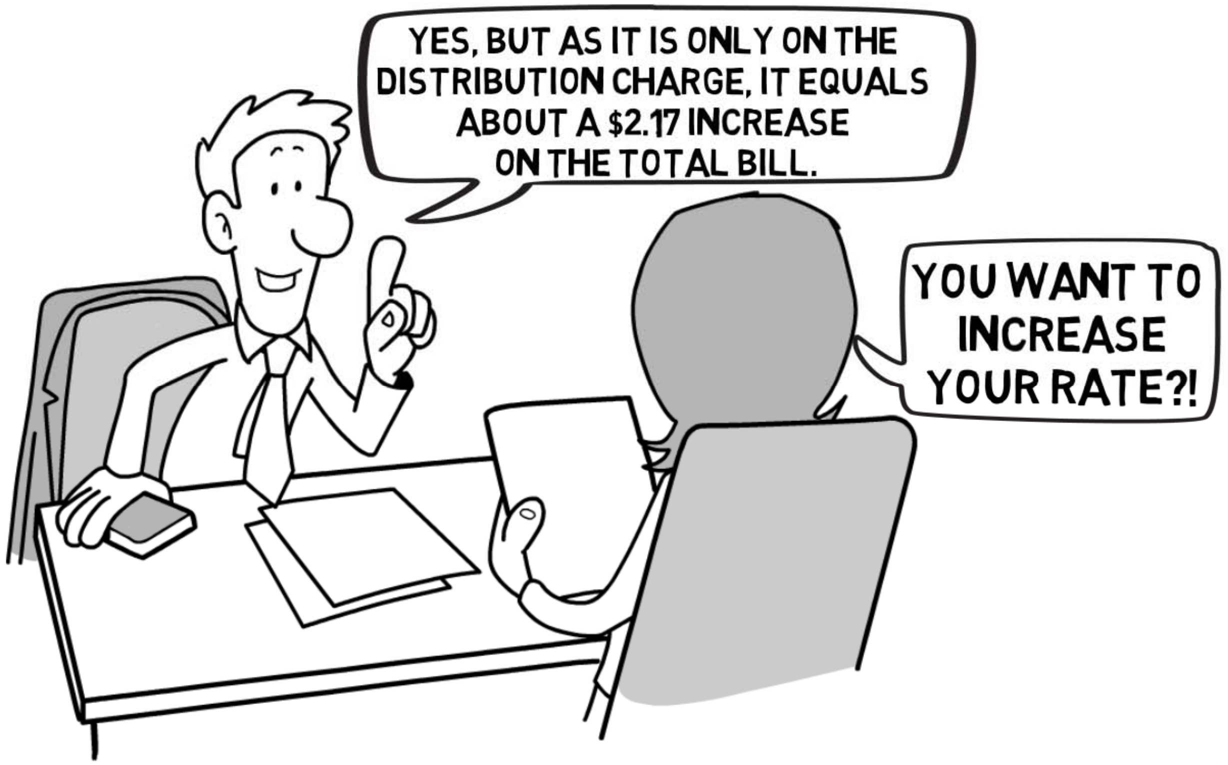


While we understand the concerns around rising electricity costs, the unfortunate reality is, additional financial resources are needed for us to continue addressing our community's electrical distribution needs.





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.

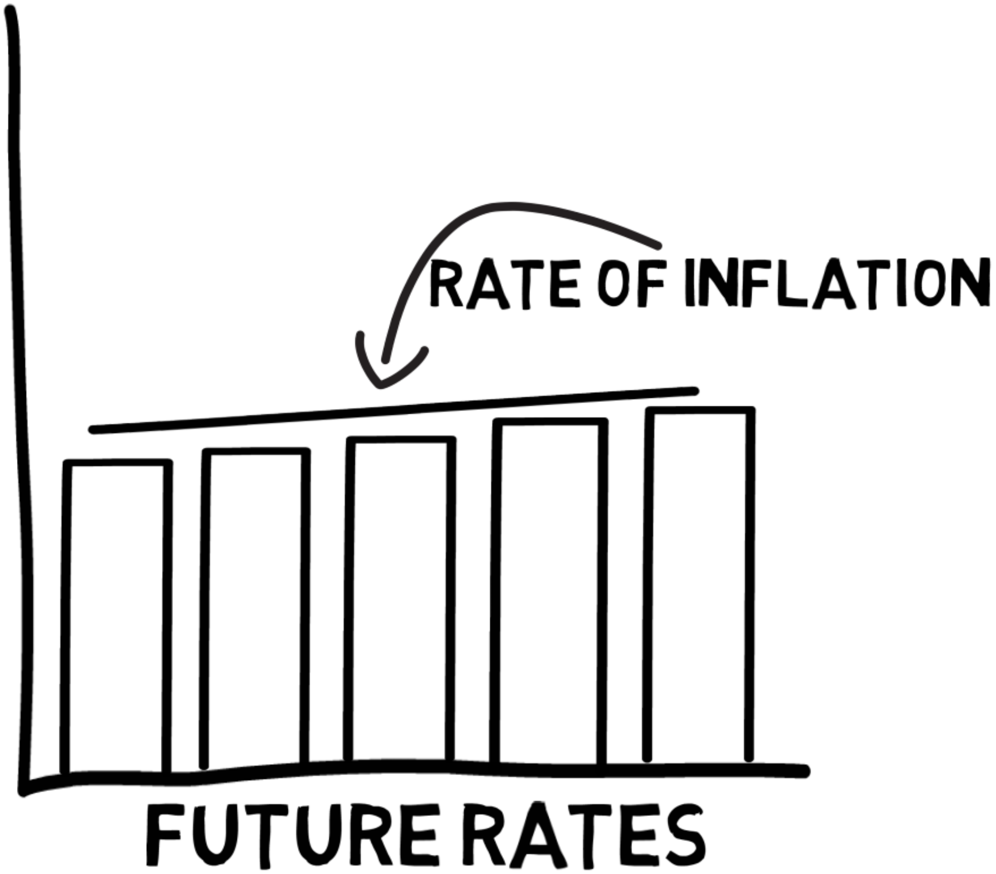
16.5%

PUC PORTION OF THE ELECTRICITY BILL

2.1%

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.

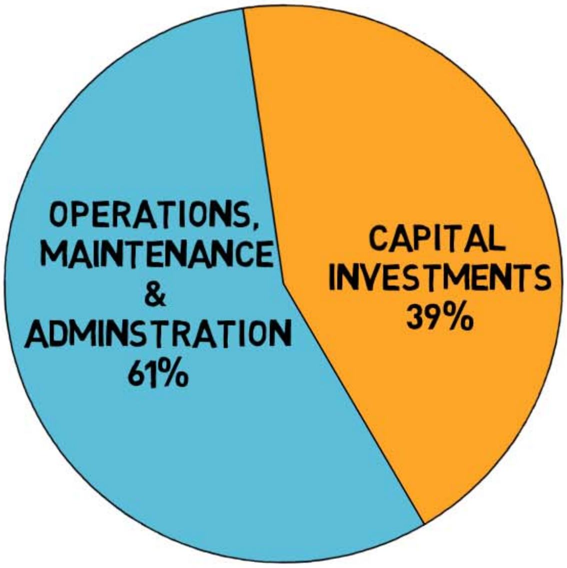


As mentioned earlier, this rate increase is largely driven by increased costs which we will be breaking down in the upcoming videos.

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:

OPERATIONS, MAINTENANCE & ADMINISTRATION



61%
OR
2 MILLION
DOLLARS

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.

21%
NEW REGULATORY REQUIREMENTS

OVERHEAD TRANSFORMER
PCB CHEMICAL
TESTING & REPLACEMENT

New meter reading requirements for large general service customers.

21%

NEW REGULATORY REQUIREMENTS (CONT'D)

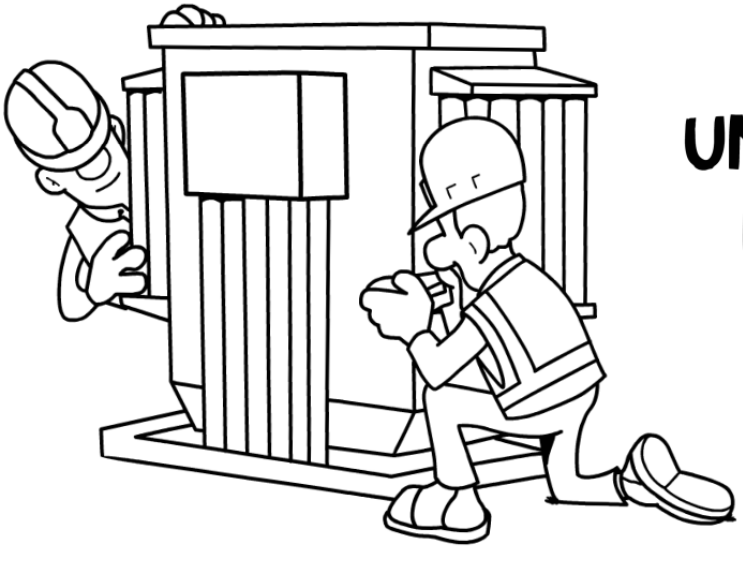
NEW METER
READING REQUIREMENTS

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.

21%

NEW REGULATORY REQUIREMENTS (CONT'D)



UNDER FREQUENCY
LOAD SHEDDING

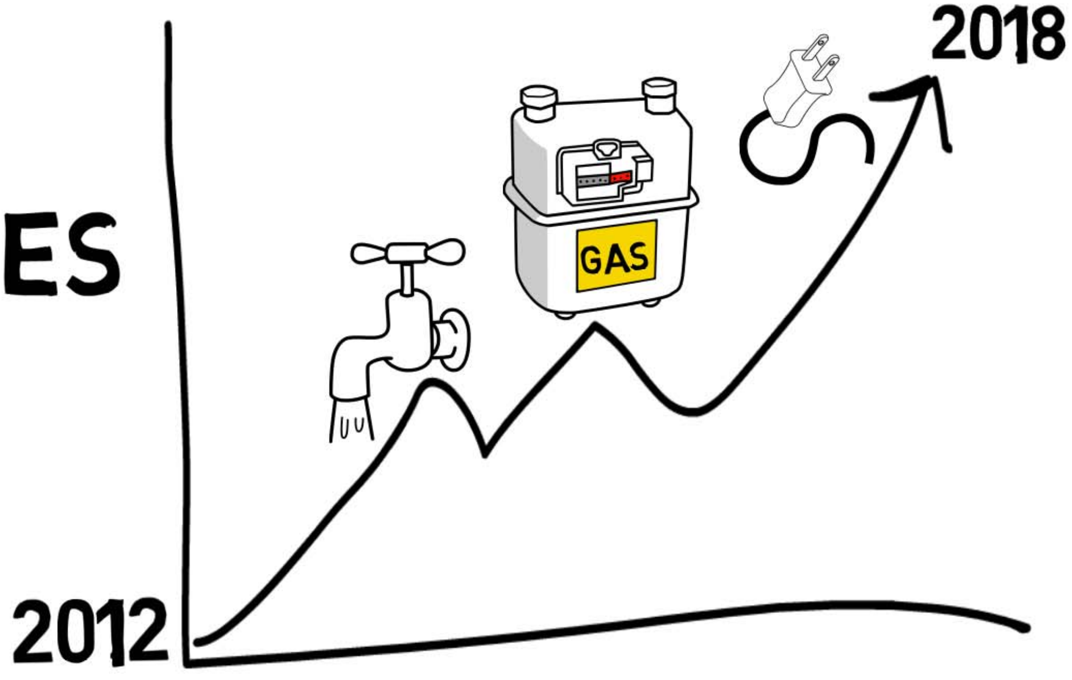
And finally, the hiring of an additional staff member to assist with growing OEB requirements – all contribute to the increased costs in Regulatory Requirements.

21%
NEW REGULATORY REQUIREMENTS
(CONT'D)

ADDTIONAL STAFF

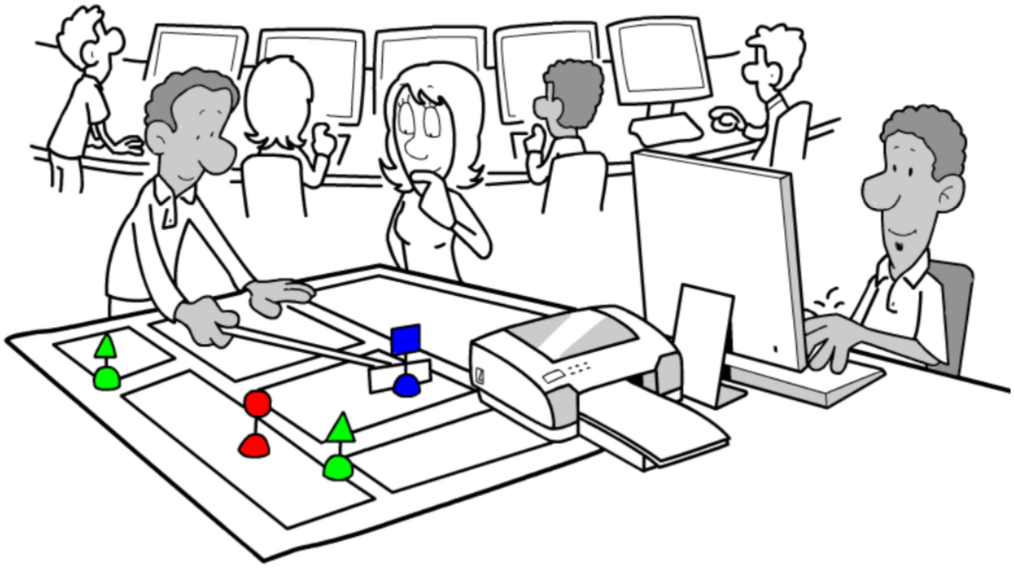
10 percent of the increase covers the rising cost of utilities since our last application. This accounts for basic utilities for the transmission and distribution stations, and the administrative building and service center.

10%
UTILITIES



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.

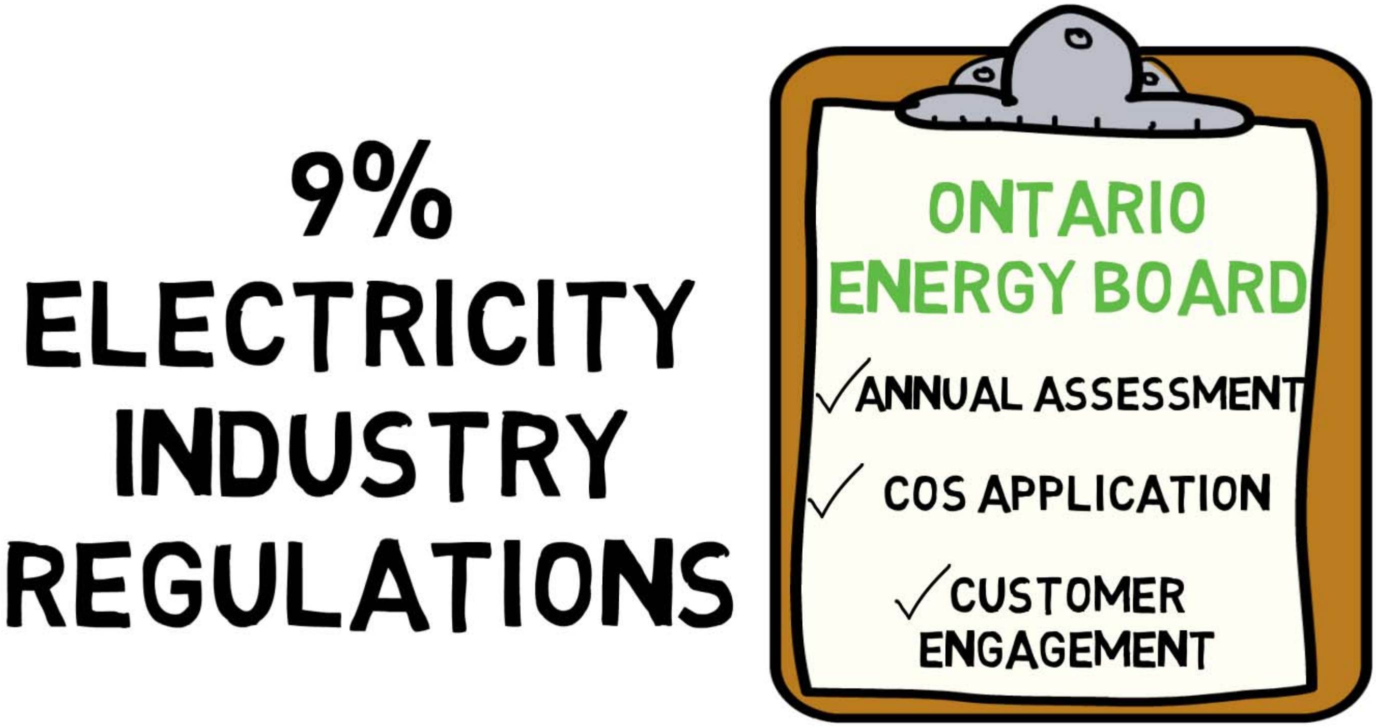
5% SMART METER BILLING SYSTEM



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.

7% BAD DEBT

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.

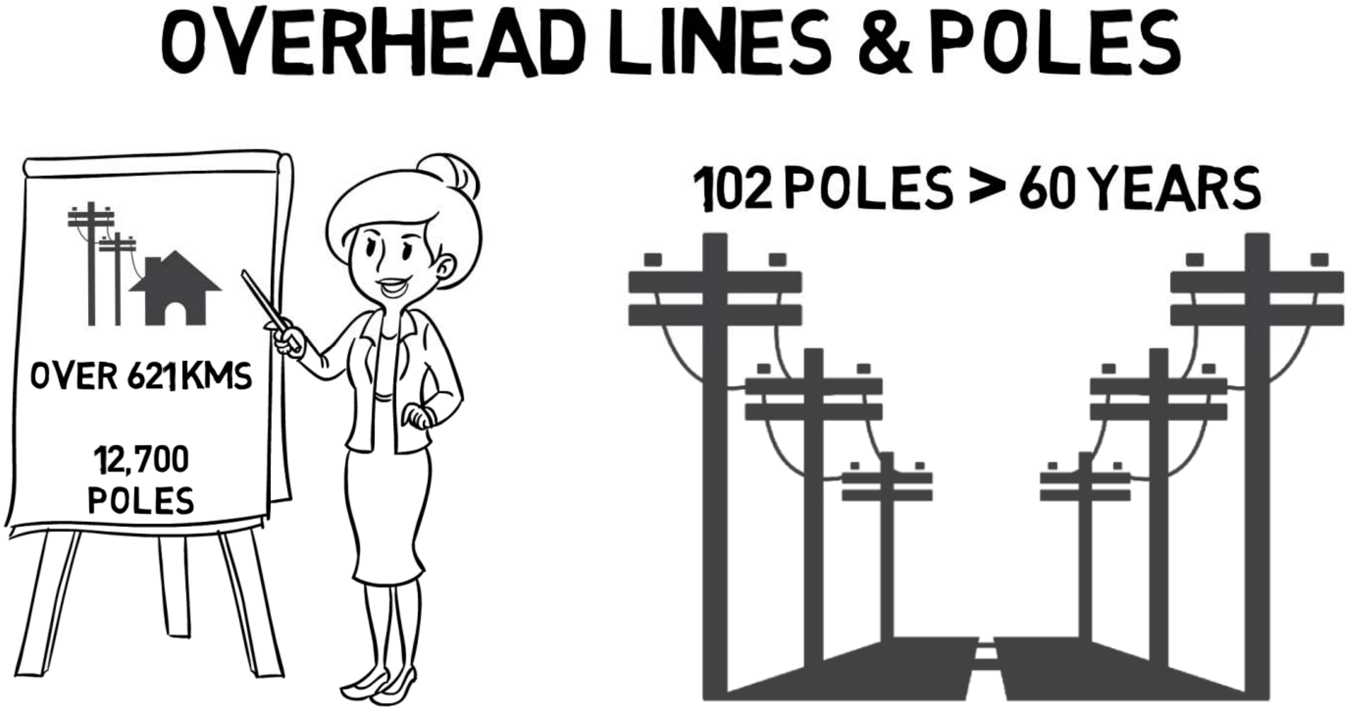
The remaining 41% of the increase in service revenue requirements is driven largely by inflationary growth in things like; employee wages, benefits, contracted services, insurance costs, and fuel expenses.

41%
INFLATIONARY
GROWTH

CAPITAL INVESTMENT PROJECTS – VIDEO 6

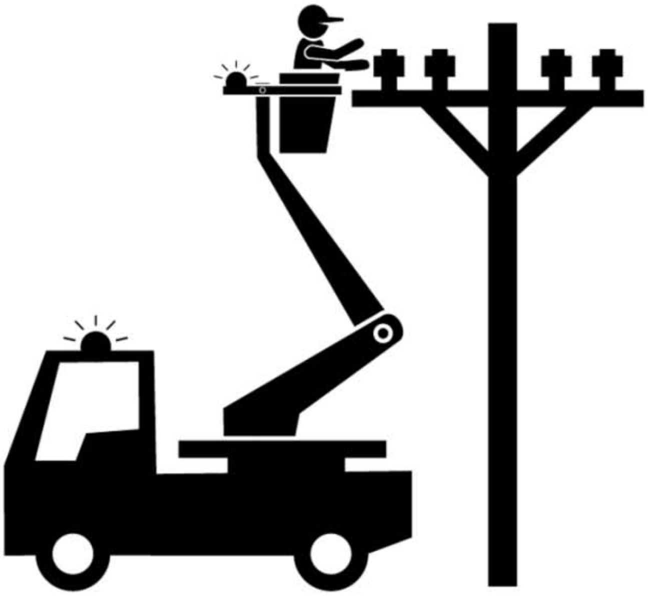
As mentioned, operations, maintenance and administrative expenses account for two-thirds of the total service revenue requirement increase. The remainder is driven by Capital Investments in infrastructure renewal. Let's explore some of the infrastructure renewal projects PUC has planned for the next 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.

150 POLES



WITHIN THE NEXT 10 YEARS

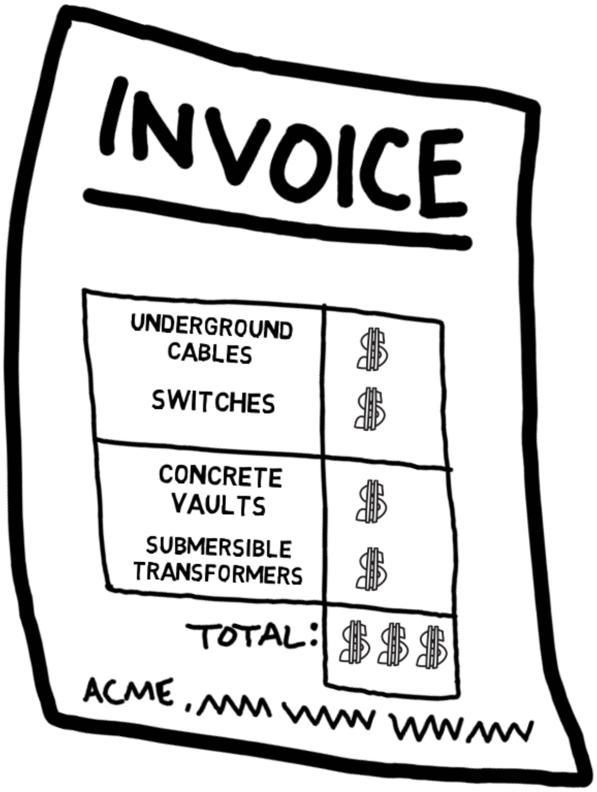
The underground electrical distribution system is comprised of approximately 122 kms of cable, 30 kms of which are approaching the end of their service life.

UNDERGROUND SYSTEM

122 KMS OF CABLE

30 KMS NEAR/END OF SERVICE LIFE

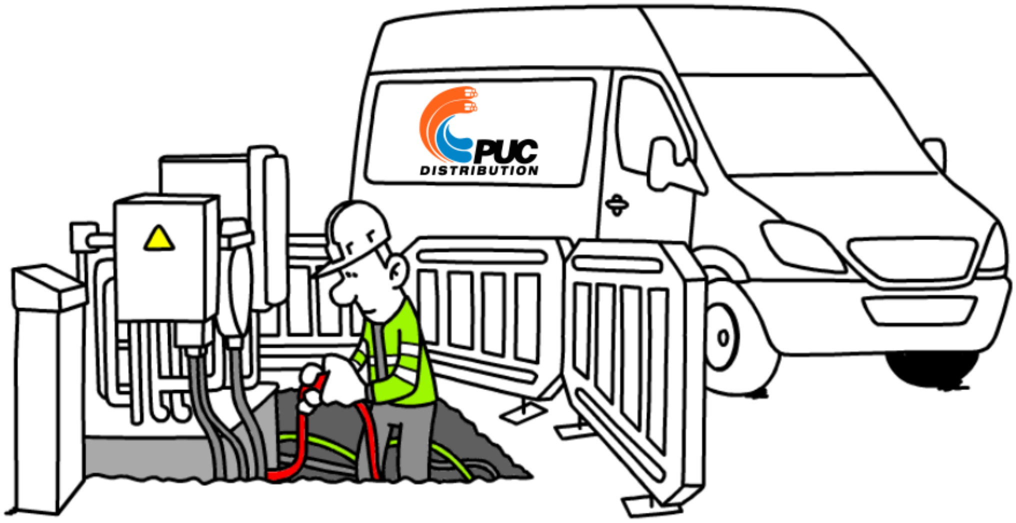
Additionally, underground infrastructure like switches, concrete vaults, and submersible transformers are also a priority for replacement based on their condition.



Our plan will continue addressing this aging infrastructure, and focus on neighbourhoods with high equipment failure rates.

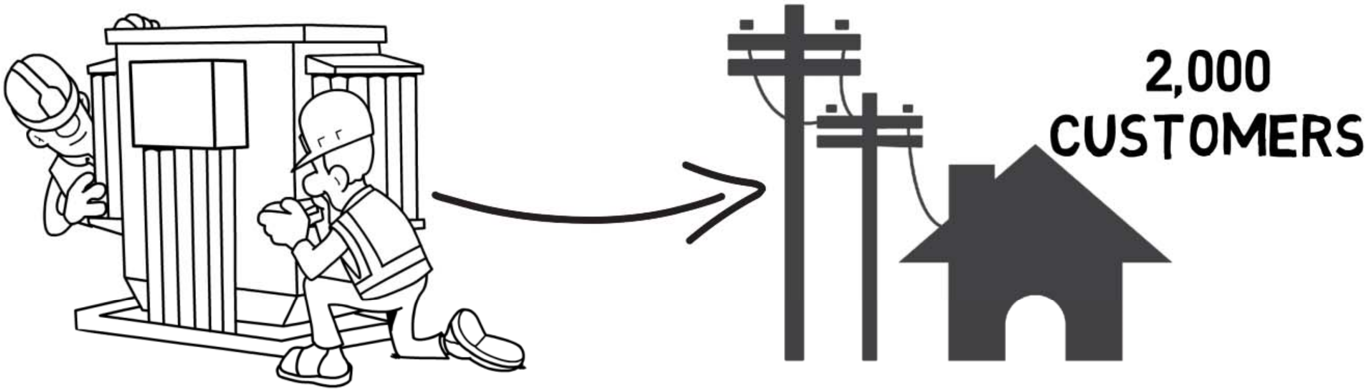
UNDERGROUND SYSTEM

122 KMS OF CABLE
30 KMS NEAR/END OF SERVICE LIFE



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.

DISTRIBUTION STATIONS / SUB-STATIONS



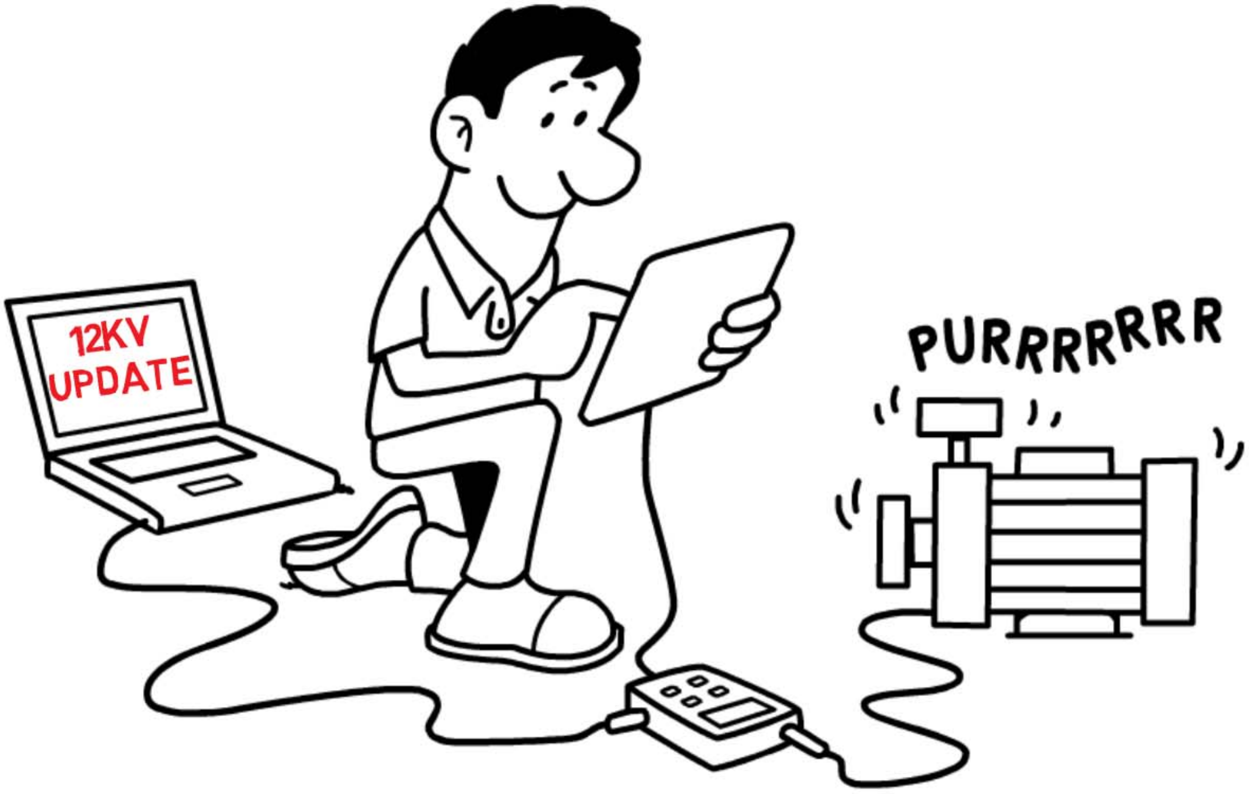
It's important to note that the average service life for a transformer is 40 years so special attention needs to be paid to those located within our substations, as 66% of station transformers have been in service longer than 35 years. With that in mind, we plan on replacing two substations by 2022.

TRANSFORMERS

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.

VOLTAGE CONVERSION

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.



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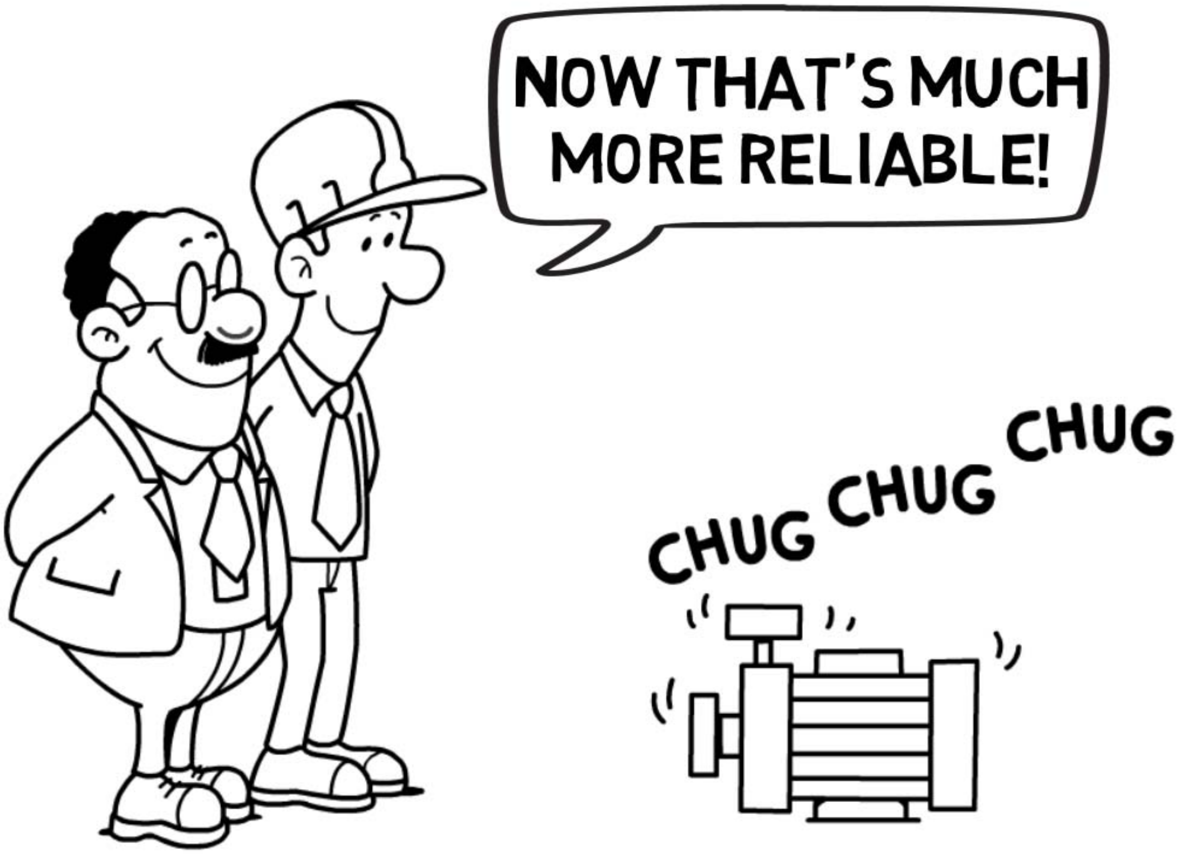
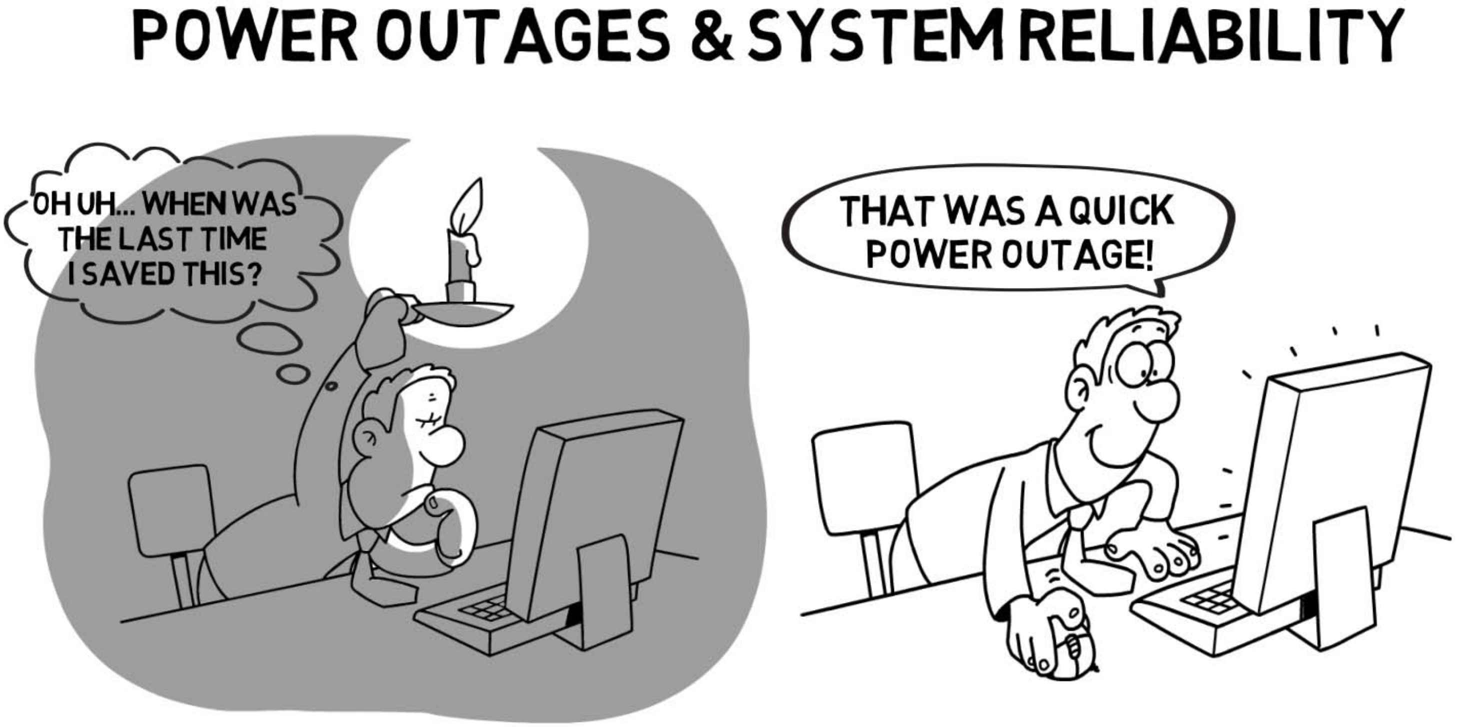
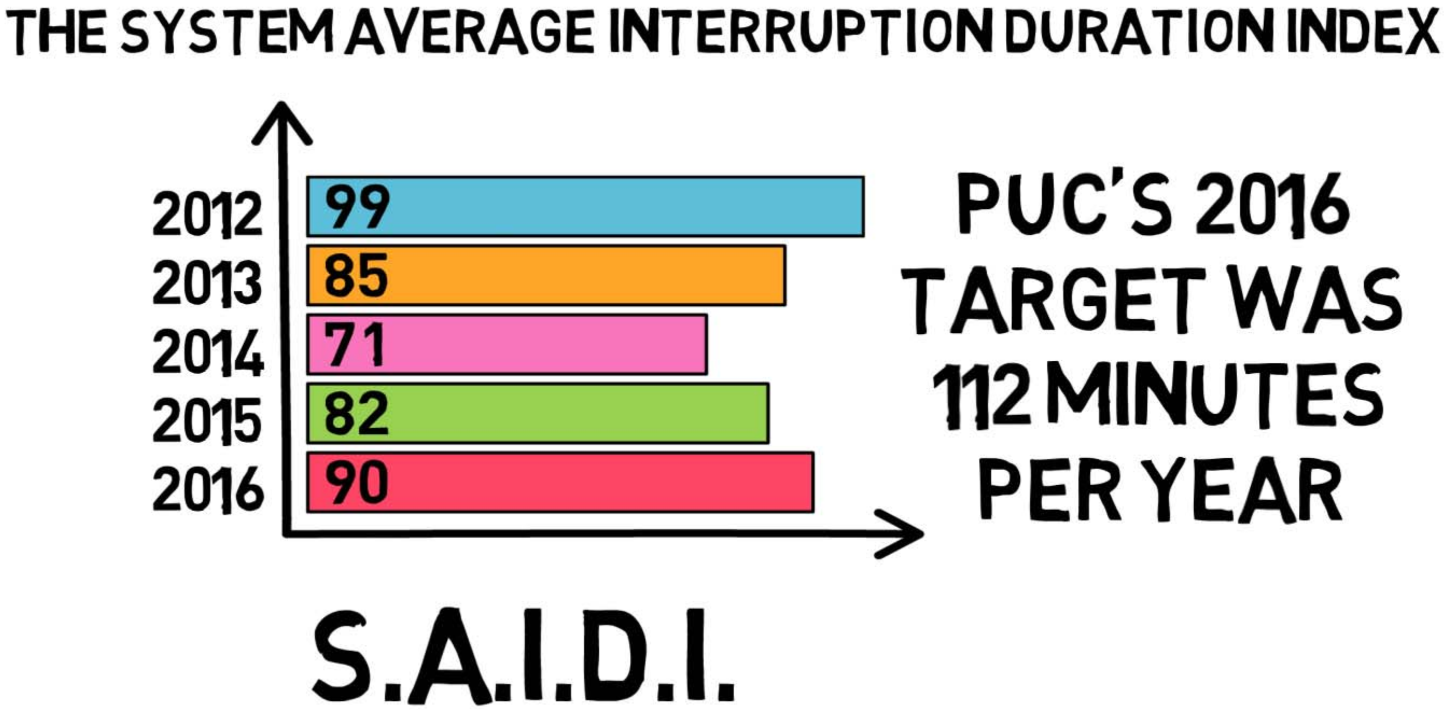


POWER OUTAGES AND SYSTEM RELIABILITY – VIDEO 7

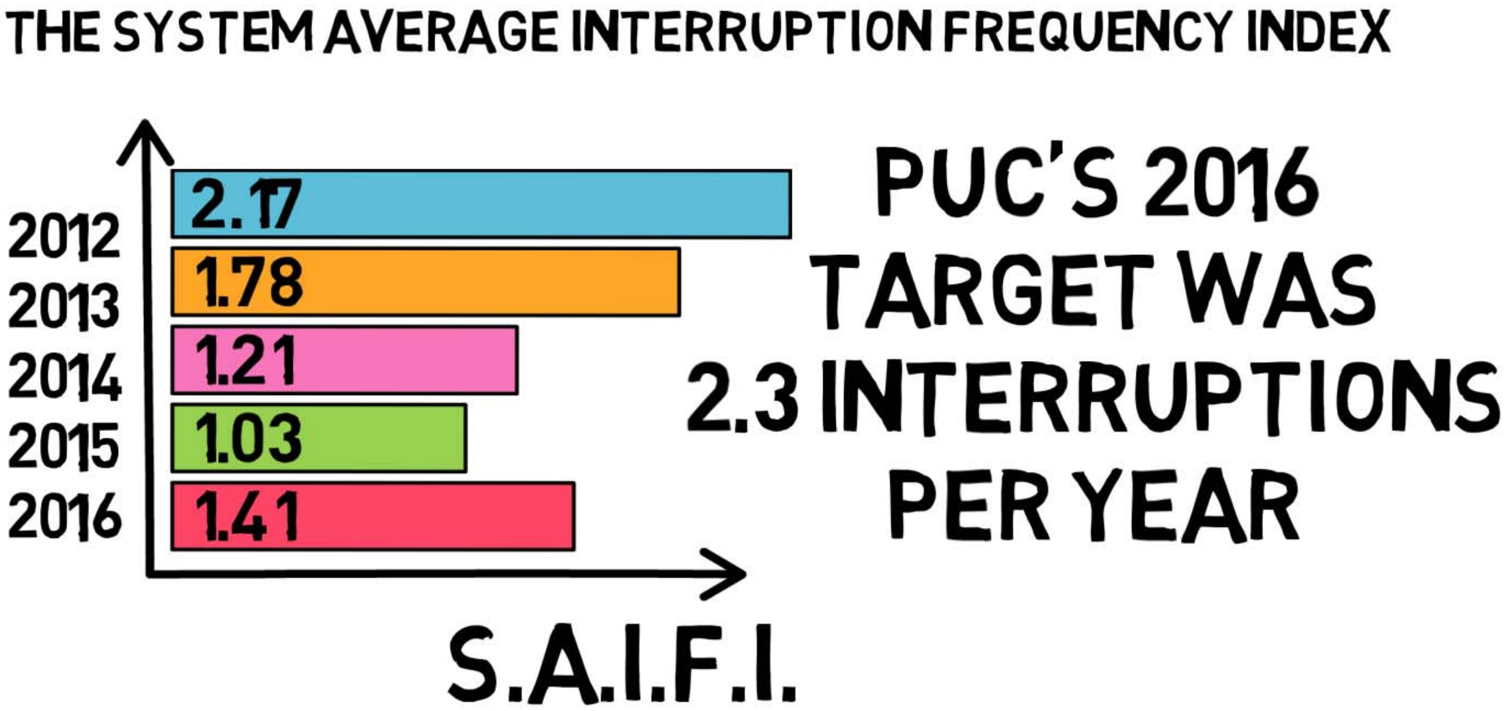
Power outages are an unfortunate reality in the electricity industry. That said, at PUC we work very hard to keep outages to a minimum and if required, as short as possible.



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.

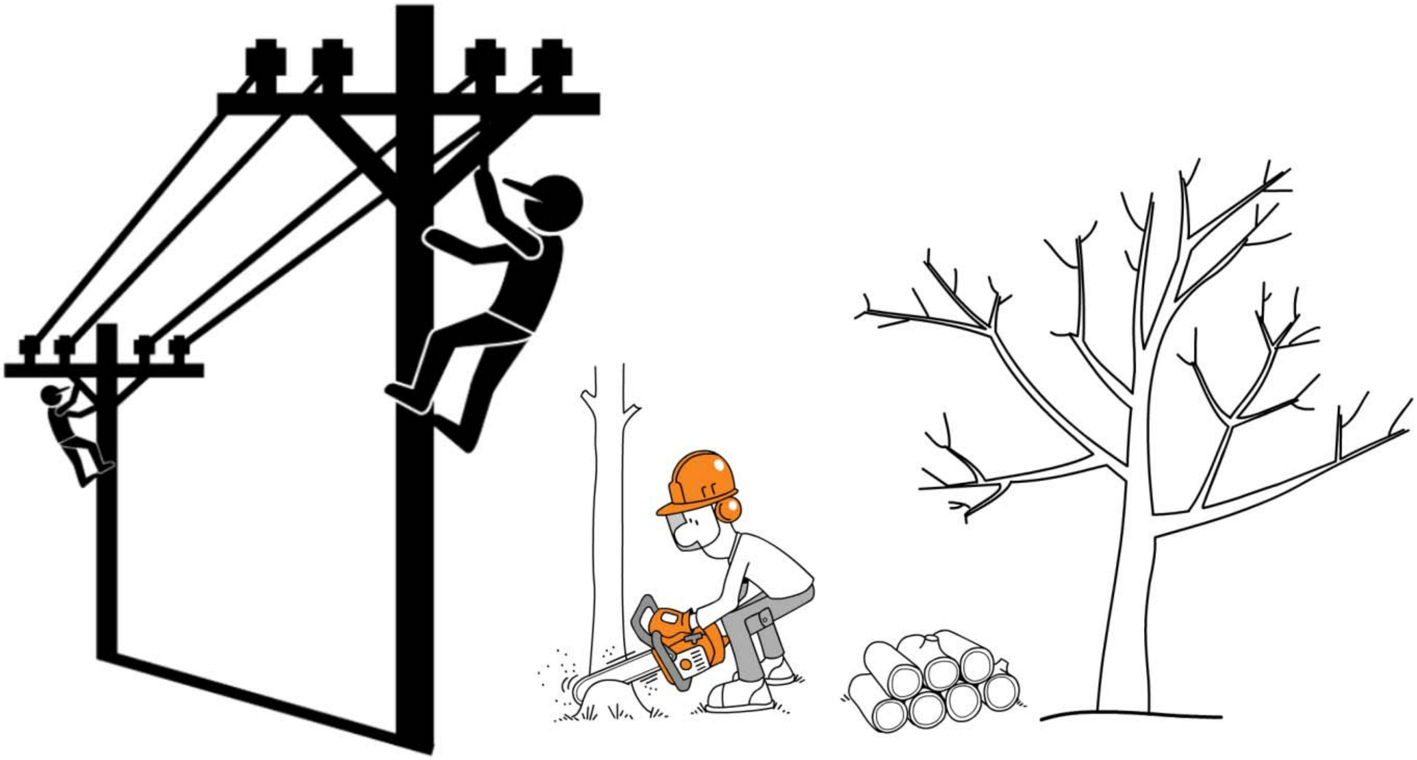


The other annual industry measurement is the System Average Interruption Frequency Index, or SAIFI. This is measured by the average number of times the power to a customer is interrupted. In 2016, the total number of times the average customer experienced an interruption was 1.4 times. This is well below the target of 2.3 interruptions per year.

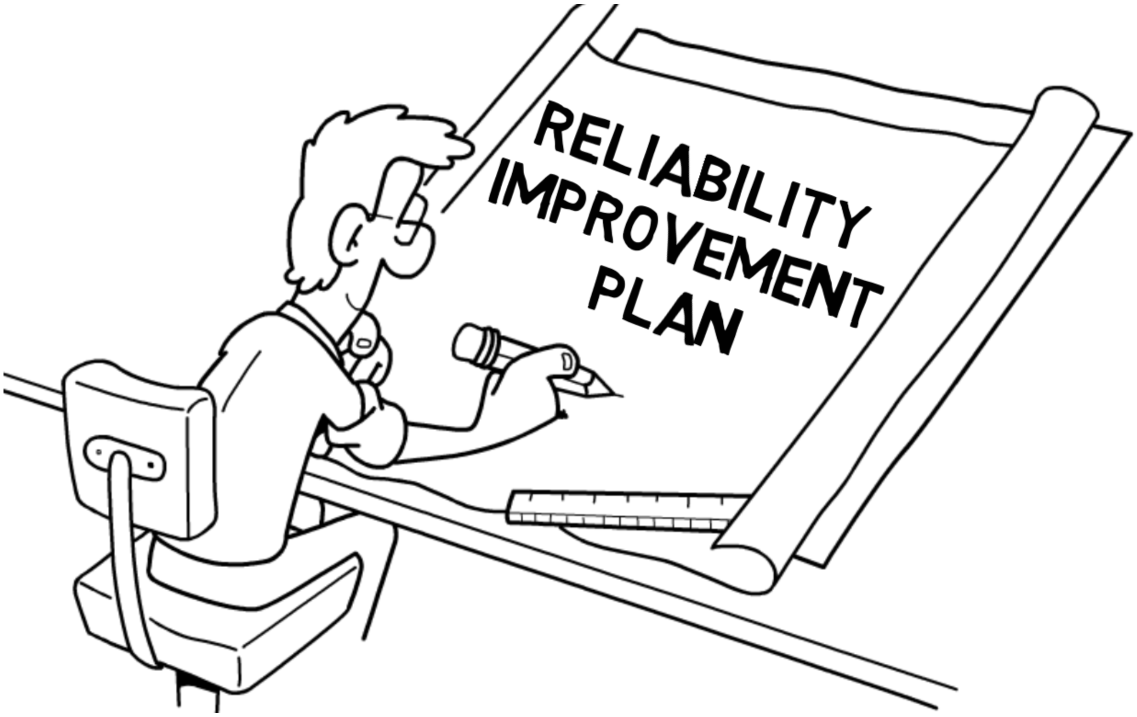


As you can see, PUC's reliability metrics are trending in a positive direction.

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.



APPENDIX 3

Capital Expenditure Summary, Board Appendix 2-AB

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period: *2017*

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)					
	2012			2013			2014			2015			2016			2017	2018	2019	2020	2021	2022
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var						
	$ '000		%	*$ '000*		%	*$ '000*		%	*$ '000*		%	*$ '000*		%	*$ '000*					
System Access	1,132	7,938	601.1%	1,069	2,310	116.1%	2,957	2,532	-14.4%	1,265	1,549	22.4%	1,215	1,212	-0.2%	1,271	1,511	1,615	2,086	1,604	1,560
System Renewal	6,043	4,821	-20.2%	6,525	6,083	-6.8%	3,813	3,754	-1.6%	4,753	4,640	-2.4%	4,543	4,244	-6.6%	3,372	3,761	6,906	3,296	4,533	7,093
System Service	-	-	--	-	-	--	-	-	--	-	-	--	-	-	--	38	-	-	-	-	-
General Plant	17,803	23,269	30.7%	1,314	2,028	54.4%	175	376	114.1%	69	67	-3.1%	-	83	--	-	86	55	62	60	55
TOTAL EXPENDITURE	24,978	36,028	44.2%	8,907	10,421	17.0%	6,946	6,661	-4.1%	6,087	6,256	2.8%	5,758	5,538	-3.8%	4,682	5,358	8,576	5,445	6,197	8,708
System O&M	$ 6,259	$ 5,853	-6.5%	$ 6,154	$ 5,992	-2.6%	$ 5,530	$ 5,773	4.4%	$ 5,819	$ 5,978	2.7%	$ 6,201	$ 5,978	-3.6%	$ 5,857	$ 6,213	$ 6,337	$ 6,464	$ 6,593	$ 6,725

APPENDIX 4

Capital Projects Table, Board Appendix 2-AA

Appendix 2-AA
Capital Projects Table

Projects	2013	2014	2015	2016	2017 Bridge Year	2018 Test Year
Reporting Basis	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
New Services & Subdivisions						
Land Rights (Formally known as Account 1906)		3,411		1,736	1,057	1,138
Buildings						
Transformer Station Equipment >50 kV	10,633		14,422		5,143	5,541
Distribution Station Equipment <50 kV		41		468	104	113
Poles, Towers & Fixtures	256,877	401,663	184,799	274,915	229,541	247,298
Overhead Conductors & Devices	64,863	200,363	70,055	101,891	89,737	96,679
Underground Conduit	114,781	177,913	39,290	37,655	75,874	81,744
Underground Conductors & Devices	107,784	171,551	209,801	94,176	119,734	128,997
Line Transformers	238,554	367,159	418,565	279,567	267,636	288,341
Services (Overhead & Underground)	810,182	527,136	357,901	347,857	419,376	451,820
Meters	799	76	10,431	1,376	2,603	2,805
Sub-Total	**1,604,473**	**1,849,313**	**1,305,264**	**1,139,641**	**1,210,805**	**1,304,476**
Joint Use						
Poles, Towers & Fixtures	1,132,205	1,010,215	74,737	35,201	86,257	123,906
Overhead Conductors & Devices	114,063	66,940		28,982	8,042	11,552
Line Transformers	19,507	10,386	-4,856	8,696	1,292	1,856
Sub-Total	**1,265,775**	**1,087,540**	**69,881**	**72,879**	**95,590**	**137,313**
Meters						
Transformer Station Equipment >50 kV				529	220	146
Line Transformers				11,410	4,740	3,157
Services (Overhead & Underground)		561			233	155
Meters	229,274	139,712	42,513	82,277	205,105	136,601
Sub-Total	**229,274**	**140,273**	**42,513**	**94,217**	**210,298**	**140,060**
City Projects						
Poles, Towers & Fixtures		41,491	63,781	15,328	19,709	22,649
Overhead Conductors & Devices		8,524	24,949	11,466	7,344	8,440
Underground Conduit	12,345	78,700	120,026	86,962	48,705	55,971
Underground Conductors & Devices	213,579	348,298	379,454	41,381	160,597	184,556
Line Transformers		10,421	-1,654	-3,118	923	1,061
Services (Overhead & Underground)		10,198		180	1,696	1,949
Sub-Total	**225,924**	**497,632**	**586,556**	**152,198**	**238,975**	**274,627**
Distribution Overhead Renewal						
Land Rights (Formally known as Account 1906)		3,387			450	483
Distribution Station Equipment <50 kV		224		-96,685	-12,806	-13,752
Poles, Towers & Fixtures	166,342	631,378	644,093	355,614	238,631	256,256
Overhead Conductors & Devices	84,447	187,156	310,734	210,691	105,284	113,061
Underground Conduit	48,061	515		850	6,562	7,047
Underground Conductors & Devices		18,303	32,261	15,357	8,752	9,398
Line Transformers	30,758	122,900	40,144	128,906	42,844	46,008
Services (Overhead & Underground)				1,465	195	209
Meters	13,967				1,854	1,991
System Supervisor Equipment	1,154				153	165
Sub-Total	**344,730**	**963,864**	**1,027,231**	**616,199**	**391,918**	**420,865**
Distribution Underground Renewal						
Land Rights (Formally known as Account 1906)				4,740	940	
Poles, Towers & Fixtures	106	6,556	2,026	21,084	5,905	
Overhead Conductors & Devices	923		2,060	226	636	
Underground Conduit	50,542	17,968	128,515	86,025	56,141	
Underground Conductors & Devices	14,008	43,641.17	145,481.57	149,431.11	69,928	
Line Transformers		9,389.49	117,080.24	114,162.51	47,728	
Services (Overhead & Underground)	1,726				342	
Sub-Total	**67,304**	**77,555**	**395,164**	**375,669**	**181,621**	**0**
Forced Overhead Renewal						
Poles, Towers & Fixtures	174,753	145,135	107,906	155,818	177,116	190,818
Overhead Conductors & Devices	70,826	28,380	30,341	42,914	52,339	56,388
Underground Conduit			46	2,390	740	797
Underground Conductors & Devices			1,075	3,834	1,490	1,605
Line Transformers	40,398	8,804	40,494	72,397	49,192	52,998
Services (Overhead & Underground)	1,572	3,662			1,588	1,711
Meters	12,886	1,300			4,305	4,638
Sub-Total	**300,434**	**187,280**	**179,862**	**277,353**	**286,770**	**308,955**
Forced Underground Renewal						
Overhead Conductors & Devices				2,011	1,299	1,575

Underground Conductors & Devices				23,637	15,271	18,509
Line Transformers			132,840	236,062	238,336	288,871
Sub-Total	**0**	**0**	**132,840**	**261,710**	**254,906**	**308,955**
Restricted Wire Replacement						
Poles, Towers & Fixtures	166,908	23,679	130,895	372,010	274,814	418,175
Overhead Conductors & Devices	195,224	59,650	90,998	371,776	284,386	432,741
Line Transformers	15,436	12,128	36,009	133,426	78,066	118,790
Sub-Total	**377,568**	**95,458**	**257,902**	**877,211**	**637,266**	**969,706**
Transformers						
Line Transformers	88,125			59,775		56,024
Sub-Total	**88,125**	**0**	**0**	**59,775**	**0**	**56,024**
Substation 16						
Distribution Station Equipment <50 kV	19,871			35,585	73,445	121,065
Overhead Conductors & Devices	14,420				19,098	31,481
Line Transformers	122,592				162,362	267,633
Sub-Total	**156,883**	**0**	**0**	**35,585**	**254,906**	**420,179**
Station Upgrades - Dx						
Transformer Station Equipment >50 kV	49,279				12,288	7,759
Distribution Station Equipment <50 kV	855,072	358,362	433,146	315,900	489,365	308,987
Poles, Towers & Fixtures	348	563		850	439	277
Overhead Conductors & Devices	3,135			50,557	13,389	8,454
Underground Conduit		7,042			1,756	1,109
Services (Overhead & Underground)				51	13	8
System Supervisor Equipment		6,466		9,708	4,033	2,547
Sub-Total	**907,833**	**372,433**	**433,146**	**377,066**	**521,283**	**329,140**
Station Upgrades - Tx						
Transformer Station Equipment >50 kV	387,967	459,406	73,236	71,955		105,163
Distribution Station Equipment <50 kV	11,738	30,374		21,672		6,758
Poles, Towers & Fixtures	995					105
Overhead Conductors & Devices				202		21
Sub-Total	**400,700**	**489,779**	**73,236**	**93,829**	**0**	**112,048**
Voltage Conversion						
Distribution Station Equipment <50 kV	935		257,569		86,788	81,568
Poles, Towers & Fixtures	20,689		646,133	371,099	348,464	327,507
Overhead Conductors & Devices	30,175	45,055	336,557	457,601	291,882	274,327
Underground Conduit	526		51,597	163,259	72,311	67,962
Underground Conductors & Devices	5,787		17,822	5,606	9,809	9,219
Line Transformers	19,694	681	299,308	149,900	157,654	148,173
Services (Overhead & Underground)	5,170				1,736	1,631
Sub-Total	**82,976**	**45,737**	**1,608,986**	**1,147,466**	**968,644**	**910,387**
Switch Replacement						
Distribution Station Equipment <50 kV						
Poles, Towers & Fixtures		13,236				
Overhead Conductors & Devices	66,736	105,123.67	99,881.12			
Underground Conductors & Devices		18.71				
Line Transformers	46,482	4,578.38				
Services (Overhead & Underground)	14,590					
Sub-Total	**127,808**	**122,957**	**99,881**	**0**	**0**	**0**
Insulator Replacement						
Poles, Towers & Fixtures	291,484	4,489				
Overhead Conductors & Devices	10,491	242,586.42	185,049.10			
Sub-Total	**301,975**	**247,076**	**185,049**	**0**	**0**	**0**
New Building						
Buildings	1,861,207	244,854	66,532	82,630		
Poles, Towers & Fixtures	11					
Sub-Total	**1,861,219**	**244,854**	**66,532**	**82,630**	**0**	**0**
POD Generation						
Poles, Towers & Fixtures		2,726				
Sub-Total	**0**	**2,726**	**0**	**0**	**0**	**0**
34.5 kV Expansion						
Distribution Station Equipment <50 kV		86				
Underground Conductors & Devices		902.05				
Sub-Total	**0**	**988**	**0**	**0**	**0**	**0**
Substation 19						
Distribution Station Equipment <50 kV		163,164				
Sub-Total	**0**	**163,164**	**0**	**0**	**0**	**0**
Energy Storage Project						
Transformer Station Equipment >50 kV		158,518	-12,822	203,252.56	425,000	
Sub-Total	**0**	**158,518**	**-12,822**	**203,253**	**425,000**	**0**
PMH Replacement Program						
Distribution Station Equipment <50 kV		16,238				

Poles, Towers & Fixtures		836.63				
Overhead Conductors & Devices	11,064	10,455.85				
Underground Conductors & Devices	1,976					
Line Transformers		99,485.92	49,302.52	87,999		
Sub-Total	**13,040**	**127,016**	**49,303**	**87,999**	**0**	**0**
Substation 10						
Distribution Station Equipment <50 kV	2,942,315	674,216	174,344			
Poles, Towers & Fixtures	109,521					
Overhead Conductors & Devices	97,288	5,815.08	236.58			
Underground Conductors & Devices	57,863	6.34				
Line Transformers	35,219					
System Supervisor Equipment	32,153	21,741.08	4,349.42			
Sub-Total	**3,274,360**	**701,779**	**178,930**	**0**	**0**	**0**
SCADA						
Transformer Station Equipment >50 kV			25,347			4,170
Distribution Station Equipment <50 kV	128,475	970				21,297
System Supervisor Equipment	2,498	128,386.27	201.65	33,359		27,055
Sub-Total	**130,973**	**129,357**	**25,548**	**33,359**	**0**	**52,522**
Miscellaneous	36,153	1,483	5,693	588	0	63,099
Total	**11,797,527**	**7,706,781**	**6,710,694**	**5,988,627**	**5,677,982**	**5,808,354**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets ***(input as negative)***						
Total	**11,797,527**	**7,706,781**	**6,710,694**	**5,988,627**	**5,677,982**	**5,808,354**

APPENDIX 5

Overhead Expense, Board Appendix 2-D

Appendix 2-D
Overhead Expense

Applicants are to provide a breakdown of OM&A before capitalization in the below table. OM&A before capitalization may be broken down by cost center, program, drivers or another format best suited to focus on capitalized vs. uncapitalized OM&A.

OM&A Before Capitalization	**2014 Historical Year**	**2015 Historical Year**	**2016 Historical Year**	**2017 Bridge Year**	**2018 Test Year**
Total OM&A Before Capitalization (B)	$ 12,900,367	$ 13,023,046	$ 12,985,961	$ 13,369,918	$ 13,625,799

Applicants are to provide a breakdown of capitalized OM&A in the below table. Capitalized OM&A may be broken down using the categories listed in the table below if possible. Otherwise, applicants are to provide its own break down of capitalized OM&A.

Capitalized OM&A	**2014 Historical Year**	**2015 Historical Year**	**2016 Historical Year**	**2017 Bridge Year**	**2018 Test Year**	**Directly Attributable? (Yes/No)**	**Explanation for Change in Overhead Capitalized**
Material	$ 270,974	$ 339,460	$ 300,712	$ 356,433	$ 363,562	Yes	
Engineering	$ 632,251	$ 564,975	$ 553,561	$ 607,495	$ 549,312	Yes	
Trucking	$ 595,906	$ 570,833	$ 491,515	$ 503,803	$ 513,879	Yes	
Supervisory	$ 363,896	$ 269,955	$ 275,237	$ 305,947	$ 243,213	Yes	
Total Capitalized OM&A (A)	$ 1,863,026	$ 1,745,223	$ 1,621,026	$ 1,773,677	$ 1,669,966		

% of Capitalized OM&A (=A/B)	14%	13%	12%	13%	12%		

APPENDIX 6

Renewable Generation Connection Investment Summary, Board Appendix 2-FA

Appendix 2-FA
Renewable Generation Connection Investment Summary (past investments or over the future rate setting period)

Enter the details of the Renewable Generation Connection projects as described in the appropriate section of the Filing Requirements.
All costs entered on this page will be transferred to the appropriate cells in the appendices that follow.
For Part A, Renewable Enabling Improvements (REI), these amounts will be transferred to Appendix 2 - FB
For Part B, Expansions, these amounts will be transferred to Appendix 2 - FC

If there are more than **five** projects proposed to be in-service in a certain year, please amend the tables below and ensure that the formulae for the Total Amounts in any given rate year are updated.
Based on the current methodology and allocation, amounts allocated represent 6% for REI Connection Investments and 17% for Expansion Investments. (EB-2009-0349, 6-10-2010, p. 15, note 9)

There are two scenarios described below. Separate sets of spreadsheets (2-FA, 2-FB, 2-FC) should be submited for each scenario as required.
Scenario 1: **Past Investments with No Recovery.** The distributor has made investments in the past (during the IRM Years), but has not received approval for these projects and therefore did not receive revenue from the IESO under Regulation 330/09 and did not receive ratepayer revenue for the direct benefit portion of the investment.
The WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage should correspond to the distributor's last Cost of Service approval.
The Direct Benefit portion of the calculated Revenue Requirement for each year should be summed and can be applied for recovery from the distributor's ratepayers through a rate rider.
The Provincial Recovery portion of the calculated Revenue Requirement for each year should be summed and can be applied for recovery from the IESO through a separate order.

Scenario 2: **Investments in the Test Year and Beyond.** Distributor plans to make investments in 2017 and/or beyond. These investments should be added to 2-FA in the appropriate year.
The WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage should correspond to the distributor's current application.

Part A

					Test Year				
REI Investments (Direct Benefit at 6%)	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Project 1									
Name: REI Connection Project									
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 2									
Name: REI Connection Project									
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 3									
Name: REI Connection Project									
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 4									
Name: REI Connection Project									
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 5									
Name: REI Connection Project									
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Capital Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Start-Up)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Ongoing)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Part B

					Test Year				
Expansion Investments (Direct Benefit at 17%)	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Project 1									
Name: Expansion Connection Project									
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 2									
Name: Expansion Connection Project									
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 3									
Name: Expansion Connection Project									
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 4									
Name: Expansion Connection Project									
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 5									
Name: Expansion Connection Project									
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Capital Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Start-Up)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Ongoing)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

APPENDIX 7

Renewable Generation Connection Direct Benefits, Board Appendix 2-FB

Appendix 2-FB

Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Enabling Improvement Investments

This table will calculate the distributor/provincial shares of the investments entered in Part A of Appendix 2-FA.
Enter values in green shaded cells: WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage.
For historical investments, enter these variables for your last cost of service test year. For 2017 and beyond, enter variables as in the application.
Rate Riders are not calculated for the Test Year as these assets and costs are already in the distributor's rate base/revenue requirement.

		2014			2015			2016			2017			2018 Test Year		
			Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial
		Total	6%	94%	Total	6%	94%	Total	6%	94%	Total	6%	94%	Total	6%	94%
Net Fixed Assets (average)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental OM&A (on-going, N/A for Provincial Recovery)		$0	$ -		$0	$ -		$0	$ -		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable for Provincial Recovery)		$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA	7.50%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed ST Debt	4%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed LT Debt	56%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed Equity	40%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
ST Interest	2.29%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
LT Interest	4.12%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
ROE	9.00%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Cost of Capital Total			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
OM&A			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Amortization		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed-up PILs			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Revenue Requirement			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Provincial Rate Protection				$ -			$ -			$ -			$ -			$ -
Monthly Amount Paid by IESO				$ -			$ -			$ -			$ -			$ -

		2019			2020			2021			2022		
			Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial
		Total	6%	94%	Total	6%	94%	Total	6%	94%	Total	6%	94%
Net Fixed Assets (average)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental OM&A (on-going, N/A for Provincial Recovery)		$0	$ -		$0	$ -		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable for Provincial Recovery)		$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA	7.50%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed ST Debt	4%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed LT Debt	56%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed Equity	40%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
ST Interest	2.29%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
LT Interest	4.12%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
ROE	9.00%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Cost of Capital Total			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
OM&A			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Amortization		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed-up PILs			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Revenue Requirement			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Provincial Rate Protection				$ -			$ -			$ -			$ -
Monthly Amount Paid by IESO				$ -			$ -			$ -			$ -

Note 1: The difference between the actual costs of approved eligible investments and revenue received from the IESO should be recorded in a variance account. The Board may provide regulatory accounting guidance regarding a variance account either in an individual proceeding or on a generic basis.
Note 2: For the 2016 Test Year, Costs and Revenues of the Direct Benefit are to be included in the test year applicant Rate Base and Revenues.

PILs Calculation

	2014		2015		2016		2017		2018 Test Year	
Income Tax	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial
Net Income - ROE on Rate Base	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization (6% DB and 94% P)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA (6% DB and 94% P)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Taxable income	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tax Rate (to be entered)										
Income Taxes Payable	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gross Up										
Income Taxes Payable	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed Up PILs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

	2019		2020			2021			2022	
Income Tax	Direct Benefit	Provincial	Direct Benefit	Provincial	Total	Direct Benefit	Provincial	Total	Direct Benefit	Provincial
Net Income - ROE on Rate Base	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
Amortization (6% DB and 94% P)	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
CCA (6% DB and 94% P)	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
Taxable income	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
Tax Rate (to be entered)										
Income Taxes Payable	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
Gross Up										
Income Taxes Payable	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
Grossed Up PILs	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -

		2014	2015	2016	2017	2018	2019	2020	2021	2022
Net Fixed Assets										
Enter applicable amortization in years:	25									
Opening Gross Fixed Assets			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gross Capital Additions		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Gross Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Opening Accumulated Amortization			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Current Year Amortization (before additions)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additions (half year)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Accumulated Amortization		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Opening Net Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Net Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

UCC for PILs Calculation

		2014	2015	2016	2017	2018	2019	2020	2021	2022
Opening UCC			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions (from Appendix 2-FA)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
UCC Before Half Year Rule		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Reduced UCC		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA Rate Class (to be entered)	47	47	47	47	47	47	47	47	47	47
CCA Rate (to be entered)	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
CCA		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing UCC		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

APPENDIX 8

Renewable Generation Connection Direct Benefits, Board Appendix 2-FC

Appendix 2-FC

Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Expansion Investments

This table will calculate the distributor/provincial shares of the investments entered in Part B of Appendix 2-FA.
Enter values in green shaded cells: WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage.
For historical investments, enter these variables for your last cost of service test year. For 2016 and beyond, enter variables as in the application.
Rate Riders are not calculated for the Test Year as these assets and costs are already in the distributor's rate base.

		2014			2015			2016		
		Total	Direct Benefit 17%	Provincial 83%	Total	Direct Benefit 17%	Provincial 83%	Total	Direct Benefit 17%	Provincial 83%
Net Fixed Assets (average)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental OM&A (on-going, N/A for Provincial Recovery)		$0	$ -		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable for Provincial Recovery)		$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA	7.50%		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base			$ -	$ -		$ -	$ -		$ -	$ -
Deemed ST Debt	4%		$ -	$ -		$ -	$ -		$ -	$ -
Deemed LT Debt	56%		$ -	$ -		$ -	$ -		$ -	$ -
Deemed Equity	40%		$ -	$ -		$ -	$ -		$ -	$ -
ST Interest	2.29%		$ -	$ -		$ -	$ -		$ -	$ -
LT Interest	4.12%		$ -	$ -		$ -	$ -		$ -	$ -
ROE	9.00%		$ -	$ -		$ -	$ -		$ -	$ -
Cost of Capital Total			$ -	$ -		$ -	$ -		$ -	$ -
OM&A			$ -	$ -		$ -	$ -		$ -	$ -
Amortization		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed-up PILs			$ -	$ -		$ -	$ -		$ -	$ -
Revenue Requirement			$ -	$ -		$ -	$ -		$ -	$ -
Provincial Rate Protection				$ -			$ -			$ -
Monthly Amount Paid by IESO				$ -			$ -			$ -

	2017			2018 Test Year			2019		
	Total	Direct Benefit 17%	Provincial 83%	Total	Direct Benefit 17%	Provincial 83%	Total	Direct Benefit 17%	Provincial 83%
Net Fixed Assets (average)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental OM&A (on-going, N/A for Provincial Recovery)	$0	$ -		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable for Provincial Recovery)	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base		$ -	$ -		$ -	$ -		$ -	$ -
Deemed ST Debt		$ -	$ -		$ -	$ -		$ -	$ -
Deemed LT Debt		$ -	$ -		$ -	$ -		$ -	$ -
Deemed Equity		$ -	$ -		$ -	$ -		$ -	$ -
ST Interest		$ -	$ -		$ -	$ -		$ -	$ -
LT Interest		$ -	$ -		$ -	$ -		$ -	$ -
ROE		$ -	$ -		$ -	$ -		$ -	$ -
Cost of Capital Total		$ -	$ -		$ -	$ -		$ -	$ -
OM&A		$ -	$ -		$ -	$ -		$ -	$ -
Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed-up PILs		$ -	$ -		$ -	$ -		$ -	$ -
Revenue Requirement		$ -	$ -		$ -	$ -		$ -	$ -
Provincial Rate Protection			$ -			$ -			$ -
Monthly Amount Paid by IESO			$ -			$ -			$ -

	2020			2021			2022		
	Total	Direct Benefit 17%	Provincial 83%	Total	Direct Benefit 17%	Provincial 83%	Total	Direct Benefit 17%	Provincial 83%
Net Fixed Assets (average)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental OM&A (on-going, N/A for Provincial Recovery)	$0	$ -		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable for Provincial Recovery)	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base		$ -	$ -		$ -	$ -		$ -	$ -
Deemed ST Debt		$ -	$ -		$ -	$ -		$ -	$ -
Deemed LT Debt		$ -	$ -		$ -	$ -		$ -	$ -
Deemed Equity		$ -	$ -		$ -	$ -		$ -	$ -
ST Interest		$ -	$ -		$ -	$ -		$ -	$ -
LT Interest		$ -	$ -		$ -	$ -		$ -	$ -
ROE		$ -	$ -		$ -	$ -		$ -	$ -
Cost of Capital Total		$ -	$ -		$ -	$ -		$ -	$ -
OM&A		$ -	$ -		$ -	$ -		$ -	$ -
Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed-up PILs		$ -	$ -		$ -	$ -		$ -	$ -
Revenue Requirement		$ -	$ -		$ -	$ -		$ -	$ -
Provincial Rate Protection			$ -			$ -			$ -
Monthly Amount Paid by IESO			$ -			$ -			$ -

Note 1: The difference between the actual costs of approved eligible investments and revenue received from the IESO should be recorded in a variance account. The Board may provide regulatory accounting guidance regarding a variance account either in an individual proceeding or on a generic basis.
Note 2: For the 2016 Test Year, Costs and Revenues of the Direct Benefit are to be included in the test year applicant Rate Base and Revenues.

PILs Calculation

Income Tax	2014		2015		2016		2017		2018 Test Year	
	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial
Net Income - ROE on Rate Base	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization (17% DB and 83% P)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA (17% DB and 83% P)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Taxable income	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tax Rate (to be entered)										
Income Taxes Payable	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gross Up										
Income Taxes Payable	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed Up PILs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Income Tax	2019			2020			2021			2022	
	Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial
			Total			Total			Total		
Net Income - ROE on Rate Base	$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Amortization (17% DB and 83% P)	$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
CCA (17% DB and 83% P)	$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Taxable income	$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Tax Rate (to be entered)											
Income Taxes Payable	$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Gross Up											
Income Taxes Payable	$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Grossed Up PILs	$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -

Net Fixed Assets		2011	2012	2013	2014	2015	2016	2017	2018	2019
Enter applicable amortization in years:	25									
Opening Gross Fixed Assets			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gross Capital Additions		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Gross Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Opening Accumulated Amortization			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Current Year Amortization (before additions)			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additions (half year)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Accumulated Amortization		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Opening Net Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Net Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

UCC for PILs Calculation		2014	2014	2014	2014	2015	2016	2017	2018	2019
Opening UCC			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions (from Appendix 2-FA)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
UCC Before Half Year Rule		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Reduced UCC		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA Rate Class (to be entered)	47	47	47	47	47	47	47	47	47	47
CCA Rate (to be entered)	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
CCA		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing UCC		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

APPENDIX 9

Service Reliability Indicators, Board Appendix 2-G

Appendix 2-G
Service Reliability and Quality Indicators
2012 - 2016

Service Reliability

Index	Including outages caused by loss of supply					Excluding outages caused by loss of supply					Excluding Major Event Days				
	2012	2013	2014	2015	2016	2012	2013	2014	2015	2016	2012	2013	2014	2015	2016
SAIDI	1.650	2.650	1.190	3.350	2.530	1.650	2.480	1.190	3.350	2.460	1.650	1.420	1.190	1.370	1.490
SAIFI	2.170	3.530	1.210	1.840	2.210	2.170	2.670	1.210	1.840	2.110	2.170	1.780	1.210	1.030	1.410

5 Year Historical Average

SAIDI					2.274					2.226					1.424
SAIFI					2.192					2.000					1.520

SAIDI = System Average Interruption Duration Index

SAIFI = System Average Interruption Frequency Index

Service Quality

Indicator	OEB Minimum Standard	2012	2013	2014	2015	2016
Low Voltage Connections	90.0%	95.8%	96.5%	93.0%	97.2%	98.9%
High Voltage Connections	90.0%	95.8%	100.0%	100.0%	98.3%	100.0%
Appointment Scheduling	90.0%	98.5%	97.6%	86.7%	92.0%	98.5%
Appointments Met	90.0%	98.4%	97.1%	95.4%	97.4%	98.3%
Rescheduling a Missed Appointment	100.0%	100.0%	100.0%	96.0%	60.0%	100.0%
Telephone Accessibility	65.0%	74.6%	80.9%	81.9%	82.3%	81.3%
Telephone Call Abandon Rate	10.0%	3.7%	2.1%	1.8%	1.6%	1.5%
Written Response to Enquires	80.0%	97.6%	98.5%	98.4%	97.3%	99.2%
Emergency Urban Response	80.0%	83.8%	95.6%	87.5%	98.4%	89.8%
Emergency Rural Response	80.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Reconnection Performance Standard	85.0%	97.7%	100.0%	100.0%	100.0%	100.0%

APPENDIX 10

Service Life Comparison, Board Appendix 2-BB

Appendix 2-BB
Service Life Comparison
Table F-1 from Kinetrics Report[1]

		Asset Details			Useful Life			USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
Parent*	#	Category| Component | Type			MIN UL	TUL	MAX UL			Years	Rate	Years	Rate	Below Min TUL	Above Max TUL
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	1830	Poles, Towers and Fixtures	45	2%	45	2%	No	No
			Overall		35	45	75	1725	Poles, Towers and Fixtures	45		45			
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	2	Fully Dressed Concrete Poles	Overall		50	60	80								
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	3	Fully Dressed Steel Poles	Overall		60	60	80								
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	4	OH Line Switch			30	45	55								
	4	OH Line Switch			30	45	55								
	5	OH Line Switch Motor			15	25	25								
	6	OH Line Switch RTU			15	20	20								
	7	OH Integral Switches			35	45	60								
	7	OH Integral Switches			35	45	60								
	8	OH Conductors			50	60	75	1835	Overhead Conductors and Devices	60	2%	60	2%	No	No
	8	OH Conductors			50	60	75	1730	Overhead Conductors and Devices	45		45			
	9	OH Transformers & Voltage Regulators			30	40	60	1850	Line Transformers	40	3%	40	3%	No	No
	10	OH Shunt Capacitor Banks			25	30	40								
	11	Reclosers			25	40	55								
	11	Reclosers			25	40	55	1730	Overhead Conductors and Devices	45	2%	45	2%	No	No
TS & MS	12	Power Transformers	Overall		30	45	60	1820	Distribution Station Equipment<50kV	40	3%	40	3%	No	No
			Bushing		10	20	30								
			Tap Changer		20	30	60								
	13	Station Service Transformer			30	45	55	1820	Distribution Station Equipment<50kV	40	3%	40	3%	No	No
	14	Station Grounding Transformer			30	40	40								
	15	Station DC System	Overall		10	20	30								
			Battery Bank		10	15	15								
			Charger		20	20	30								
	16	Station Metal Clad Switchgear	Overall		30	40	60	1820	Distribution Station Equipment<50kV	40	3%	40	3%	No	No
			Removable Breaker		25	40	60								
	17	Station Independent Breakers			35	45	65	1820	Distribution Station Equipment<50kV	40	3%	40	3%	No	No
	18	Station Switch			30	50	60	1820	Distribution Station Equipment<50kV	40	3%	40	3%	No	No
	19	Electromechanical Relays			25	35	50								
	20	Solid State Relays			10	30	45								
	21	Digital & Numeric Relays			15	20	20								
	22	Rigid Busbars			30	55	60								
	23	Steel Structure			35	50	90								
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables			60	65	75								
	25	Primary Ethylene-Propylene Rubber (EPR) Cables			20	25	25								
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried			20	25	30								
	27	Primary Non-TR XLPE Cables in Duct			20	25	30								
	27	Primary Non-TR XLPE Cables in Duct			20	25	30	1740	Underground Conductors and Devices	25	4%	25	4%	No	No
	30	Secondary PILC Cables			70	75	80								
	30	Secondary PILC Cables			70	75	80								
	31	Secondary Cables Direct Buried			25	35	40	1845	Underground Conductors and Devices	40	3%	40	3%	No	No
	31	Secondary Cables Direct Buried			25	35	40	1740	Underground Conductors and Devices	25	4%	25	4%	No	No
	32	Secondary Cables in Duct			35	40	60	1845	Underground Conductors and Devices	40	3%	40	3%	No	No
	32	Secondary Cables in Duct			35	40	60								
	33	Network Tranformers	Overall		20	35	50								
			Protector		20	35	40								
	34	Pad-Mounted Transformers			25	40	45	1850	Line Transformers	40	3%	40	3%	No	No
	35	Submersible/Vault Transformers			25	35	45								
	36	UG Foundation			35	55	70	1840	Underground Conduit	50	2%	50	2%	No	No
	36	UG Foundation			35	55	70	1735	Underground Conduit	40	3%	40	3%	No	No
	37	UG Vaults	Overall		40	60	80								
			Roof		20	30	45								
	38	UG Vault Switches			20	35	50								
	39	Pad-Mounted Switchgear			20	30	45	1845	Underground Conductors and Devices	40	3%	40	3%	No	No
	39	Pad-Mounted Switchgear			20	30	45	1740	Underground Conductors and Devices	25	4%	25	4%	No	No
	40	Ducts			30	50	85	1840	Underground Conduit	50	2%	50	2%	No	No
	40	Ducts			30	50	85	1735	Underground Conduit	40	3%	40	3%	No	No
	41	Concrete Encased Duct Banks			35	55	80								
	42	Cable Chambers			50	60	80								
S	43	Remote SCADA			15	20	30	1980	System Supervisory Equipment	20	5%	20	5%	No	No

Table F-2 from Kinetrics Report[1]

	Asset Details		Useful Life Range		USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
#	Category| Component | Type						Years	Rate	Years	Rate	Below Min Range	Above Max Range
1	Office Equipment		5	15								
2	Vehicles	Trucks & Buckets	5	15								
		Trailers	5	20								
		Vans	5	10								
3	Administrative Buildings		50	75	1808	Buildings and Fixtures	50	2%	50	2%	No	No
4	Leasehold Improvements		Lease dependent									
5	Station Buildings	Station Buildings	50	75								
		Parking	25	30								
		Fence	25	60								
		Roof	20	30								
6	Computer Equipment	Hardware	3	5	1920	Computer Equipment-Hardware	5	20%	5	20%	No	No
		Software	2	5	1925	Computer Software	5	20%	5	20%	No	No
7	Equipment	Power Operated	5	10								
		Stores	5	10								
		Tools, Shop, Garage Equipment	5	10								
		Measurement & Testing Equipment	5	10								
8	Communication	Towers	60	70								
		Wireless	2	10								
9	Residential Energy Meters		25	35								
10	Industrial/Commercial Energy Meters		25	35								
11	Wholesale Energy Meters		15	30	1860	Meters	15	7%	15	7%	No	No
12	Current & Potential Transformer (CT & PT)		35	50								
13	Smart Meters		5	15	1860	Meters	15	7%	15	7%	No	No
14	Repeaters - Smart Metering		10	15	1860	Meters	15	7%	15	7%	No	No
15	Data Collectors - Smart Metering		15	20	1860	Meters	15	7%	15	7%	No	No

EXHIBIT 3:

OPERATING REVENUES

Table of Contents

APPENDIX 1 Monthly Data Used For Regression Analysis
APPENDIX 2 CDM Load Forecast Adjustment Workform 2-I
APPENDIX 3 Board Appendix 2-N Shared Services and Corporate Cost Allocation

Exhibit 3: Operating Revenue

2.3.1 Load and Revenue Forecasts

This Exhibit provides the details of PUC Distribution Inc. ("PUC Distribution") operating revenue for 2013 Board Approved, 2013 Actual, 2014 Actual, 2015 Actual, 2016 Actual, the 2017 Bridge Year ("Bridge Year") and the 2018 Test Year ("Test Year"). This Exhibit also provides a detailed variance analysis by rate classification of the operating revenue components. Distribution revenue excludes revenue from commodity sales.

PUC Distribution is proposing a total Service Revenue Requirement of $22,081,244 for the 2018 Test Year. This amount includes a Base Revenue Requirement of $19,691,584 plus Other Revenue of $2,389,661.

Other Revenue include Late Payment charges, Specific Service charges, Rent from Electric Property, Miscellaneous Service revenues, Standard Supply Service ("SSS") Administrative charges and Interest. A summary of these operating revenues is presented with a materiality analysis of variances and presented in this exhibit.

The following Table 3-1 summarizes PUC Distribution's total operating revenue. Revenue for each of the actual years is from PUC Distribution's audited Financial Statements. The Test Year is provided on the basis of both existing and proposed distribution rates.

Table 3-1: Summary of Operating Revenue

	2013 Board Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test at Current Rates	2018 Test at Proposed Rates
Distribution Throughput Revenue								
Residential	9,069,512	8,383,231	9,058,873	8,805,836	8,499,404	9,020,207	9,084,381	11,487,469
General Service <50 kW	2,664,966	2,479,550	2,662,132	2,636,671	2,537,809	2,660,109	2,640,479	3,247,287
General Service 50 to 4,999 kW	3,725,714	3,723,727	3,753,660	4,011,125	3,820,758	4,011,695	3,797,584	4,670,305
Sentinel Lighting	31,753	28,613	31,255	28,967	29,440	30,523	29,086	35,771
Street Lighting	720,198	663,166	702,906	727,781	577,771	460,504	420,382	203,298
Unmetered Scattered Load	29,206	27,443	29,446	30,919	30,762	31,000	39,984	47,454
Total Distribution	**16,241,349**	**15,305,730**	**16,238,272**	**16,241,299**	**15,495,944**	**16,214,038**	**16,011,896**	**19,691,584**
Smart meter & LRAM riders	-	**1,429,327**	**148,495**	**50,198**	**(3)**	**120,187**		
Total	**16,241,349**	**16,735,058**	**16,386,767**	**16,291,496**	**15,495,940**	**16,334,224**	**16,011,896**	**19,691,584**
Late Payment Charges	250,000	245,293	270,758	246,557	177,225	245,000	259,000	259,000
Miscellaneous Service Revenue	232,090	247,215	238,812	291,424	316,019	170,100	170,100	170,100
Other Operating Revenues	1,848,340	2,812,268	1,758,306	1,777,417	1,874,741	1,823,061	1,848,061	1,848,061
Other Income or Deductions	269,570	227,694	(74,745)	382,805	284,378	87,847	112,500	112,500
Total	**2,600,000**	**3,532,470**	**2,193,131**	**2,698,203**	**2,652,363**	**2,326,008**	**2,389,661**	**2,389,661**
Grand Total	**18,841,349**	**20,267,528**	**18,579,898**	**18,989,699**	**18,148,303**	**18,660,232**	**18,401,557**	**22,081,245**

Summary of Load and Customer/Connection Forecast

The purpose of this evidence is to present the process used by PUC Distribution to prepare the weather normalized load and customer/connection forecast used to design the proposed 2018 distribution rates.

In summary, as a starting point, PUC Distribution used the same regression analysis methodology approved by the Ontario Energy Board in its 2013 Cost of Service ("COS") application (EB-2012-0162) and updated the analysis for actual power purchases to the end of the 2016. The updated regression analysis included the variables used in the 2013 COS application but also includes two additional variables. These variables are Conservation and Demand Management ("CDM") Activity and Number of Customers. They were included since the coefficients on these variables were intuitive and the variables were statistically significant. The regression analysis methodology used in this application has also been used by a number of distributors in more recent cost of service rate applications to determine the forecasted volume. With regards to the overall process of load forecasting, PUC Distribution believes that conducting a regression analysis on historical electricity purchases to produce an equation that will predict purchases is appropriate. PUC Distribution has the data for the amount of electricity (in kWh) purchased from the IESO for use by PUC Distribution's customers. With a regression analysis, these purchases can be related to other monthly explanatory variables such as heating degree days and cooling degree days which occur in the same month. The results of the regression analysis produce an equation that predicts the purchases based on the explanatory variables. This prediction model is then used as the basis to forecast the total level of weather normalized purchases for the Bridge and the Test Year which is converted to billed kWh and kW, where applicable, by rate class. A detailed explanation of the process is provided later in this evidence. A live Excel file named “2018 PUC Load Forecast Model - With Regression Analysis” has also been provided.

Based on the Board's approval of this methodology in a number of previous costs of service applications as well as the discussion that follows, PUC Distribution submits the load forecasting methodology is reasonable at this time for the purposes of this Application.

The following provides the material to support the weather normalized load forecast used by PUC Distribution in this Application.

Table 3-2, Table 3-3, Table 3-4 and Table 3-5 below provide a summary of the weather normalized load and customer/connection forecast used in this Application.

Table 3-2: Summary of Load and Customer/Connection Forecast

Year	Billed Actual (GWh)	Growth (GWh)	Billed Weather Normal (GWh)	Growth (GWh)	Customer/ Connection Count	Growth
Billed Energy (GWh) and Customer Count / Connections						
2013 Board Approved			703.4		42,383	
2003	719.3		705.2		41,290	
2004	727.3	8.0	718.3	13.1	41,351	61
2005	717.8	(9.5)	712.5	(5.8)	41,409	58
2006	697.1	(20.6)	709.8	(2.8)	41,469	60
2007	701.8	4.7	699.3	(10.5)	41,538	69
2008	710.7	8.9	701.7	2.4	41,729	191
2009	707.8	(2.9)	699.3	(2.4)	41,995	266
2010	683.8	(24.0)	692.5	(6.8)	42,110	115
2011	711.9	28.2	712.9	20.5	42,160	50
2012	676.8	(35.2)	709.1	(3.9)	42,400	240
2013	688.2	11.5	698.7	(10.4)	42,592	192
2014	701.8	13.6	673.5	(25.2)	42,577	(15)
2015	669.4	(32.5)	658.3	(15.2)	42,590	13
2016	636.9	(32.5)	644.6	(13.7)	42,650	60
2017 Bridge			640.8	(3.7)	41,937	(713)
2018 Test			642.9	2.0	42,026	89

In the above Table 3-2, the billed GWh data from 2003 to 2016 reflects actual weather and weather normal conditions in each year. The weather normal values are the actual values adjusted by the weather normal conversion factor outlined in Table 3-8. The weather conversion factor is determined consistent with the approach outlined by the Board in Appendix 2-IA. For 2017 and 2018, the forecasted billed GWh is on a weather normal basis.

Customer/Connection values are on an average basis and street lights and sentinel lights are measured as connections. The historical connection values for street lights have been measured as devices but the 2017 and 2018 forecast has been changed to connections to be consistent with the 2017 rate order for PUC Distribution (EB-2016-0102).

On a rate class basis, the actual and forecasted billed amounts are shown in Table 3-3. Actual volumes have been weather normalized by rate class using the weather normal conversion factor from Table 3-8. The actual and forecasted number of customers/connections is shown in Table 3-4. The customer/connection usage on an actual and weather normal basis is shown in Table 3-5.

Table 3-3: Billed GWh by Rate Class

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Sentinel Lighting	Street Lights	Unmetered Scattered Load	Total
Billed Energy (GWh) - Actual							
2003	351.0	96.2	263.8	0.3	7.2	0.9	719.3
2004	356.5	95.7	266.6	0.3	7.4	0.8	727.3
2005	347.3	95.6	266.1	0.3	7.7	0.8	717.8
2006	335.4	86.8	266.2	0.3	7.6	0.9	697.1
2007	338.9	94.2	259.9	0.3	7.6	0.9	701.8
2008	347.4	93.5	261.1	0.3	7.6	0.8	710.7
2009	348.6	91.5	259.0	0.3	7.6	0.8	707.8
2010	326.5	91.4	257.0	0.3	7.8	0.8	683.8
2011	345.3	101.7	256.0	0.3	7.8	0.9	711.9
2012	316.1	97.5	254.3	0.2	7.7	0.9	676.8
2013	324.2	95.8	259.0	0.2	8.1	0.9	688.2
2014	335.0	99.2	258.8	0.2	7.8	0.9	701.8
2015	310.5	95.7	254.8	0.2	7.3	0.9	669.4
2016	288.7	92.2	250.0	0.2	4.9	0.9	636.9
Billed Energy (GWh) - Weather Normal							
2003	344.2	94.3	258.6	0.3	7.1	0.8	705.2
2004	352.1	94.5	263.3	0.3	7.3	0.8	718.3
2005	344.7	94.9	264.1	0.3	7.7	0.8	712.5
2006	341.5	88.3	271.1	0.3	7.7	0.9	709.8
2007	337.7	93.9	259.0	0.3	7.6	0.9	699.3
2008	343.0	92.3	257.8	0.3	7.5	0.8	701.7
2009	344.4	90.4	255.9	0.3	7.5	0.8	699.3
2010	330.7	92.5	260.3	0.3	7.9	0.8	692.5
2011	345.8	101.9	256.3	0.3	7.8	0.9	712.9
2012	331.2	102.1	266.5	0.3	8.1	0.9	709.1
2013	329.1	97.3	263.0	0.2	8.2	0.9	698.7
2013 Board Approved	340.6	102.2	251.6	0.3	7.9	0.9	703.4
2014	321.4	95.1	248.3	0.2	7.5	0.8	673.5
2015	305.3	94.1	250.5	0.2	7.2	0.9	658.3
2016	292.2	93.3	253.0	0.2	4.9	0.9	644.6
2017 Bridge	293.4	93.6	250.1	0.2	2.4	1.1	640.8
2018 Test	296.4	94.3	248.3	0.2	2.4	1.2	642.9

Table 3-4: Number of Customers/Connections

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Sentinel Lighting	Street Lights	Unmetered Scattered Load	Total
2003	28,544	3,230	419	466	8,619	12	41,290
2004	28,560	3,247	424	466	8,635	19	41,351
2005	28,576	3,274	431	459	8,642	27	41,409
2006	28,596	3,301	432	449	8,663	28	41,469
2007	28,630	3,302	429	443	8,707	27	41,538
2008	28,780	3,325	426	435	8,741	22	41,729
2009	28,971	3,352	433	423	8,799	17	41,995
2010	29,057	3,345	435	411	8,846	16	42,110
2011	29,124	3,366	403	402	8,846	19	42,160
2012	29,327	3,448	366	392	8,846	21	42,400
2013	29,504	3,474	373	374	8,846	21	42,592
2013 Board Approved	29,271	3,401	399	387	8,904	21	42,383
2014	29,514	3,464	370	362	8,846	21	42,577
2015	29,566	3,431	373	360	8,839	21	42,590
2016	29,620	3,414	361	362	8,872	21	42,650
2017 Bridge	29,704	3,429	357	355	8,070	22	41,937
2018 Test	29,789	3,443	353	348	8,070	23	42,026

Table 3-5: Annual Usage by Rate Class

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Sentinel Lighting	Street Lights	Unmetered Scattered Load
Actual Annual Energy Usage per Customer/Connection (kWh per customer/connection)						
2003	12,298	29,772	629,506	593	834	70,970
2004	12,482	29,480	628,742	625	854	44,350
2005	12,153	29,197	617,336	613	893	31,327
2006	11,729	26,286	616,293	610	878	30,577
2007	11,836	28,536	605,898	607	877	31,999
2008	12,070	28,113	612,967	618	872	38,560
2009	12,033	27,282	598,148	621	864	48,438
2010	11,236	27,318	590,889	628	877	52,327
2011	11,856	30,222	635,157	648	883	46,046
2012	10,779	28,271	694,847	629	875	41,047
2013	10,988	27,584	694,501	635	914	40,830
2014	11,349	28,624	699,481	672	883	41,715
2015	10,501	27,893	683,069	653	825	43,462
2016	9,748	26,999	692,397	627	549	43,012
Normalized Annual Energy Usage per Customer/Connection (kWh per customer/connection)						
2003	12,057	29,189	617,170	582	818	69,579
2004	12,328	29,115	620,965	617	844	43,802
2005	12,064	28,983	612,810	609	887	31,097
2006	11,941	26,762	627,455	621	894	31,131
2007	11,794	28,434	603,745	605	874	31,886
2008	11,917	27,756	605,203	610	861	38,072
2009	11,889	26,955	590,973	613	854	47,857
2010	11,379	27,666	598,415	636	888	52,993
2011	11,872	30,265	636,057	649	885	46,111
2012	11,294	29,621	728,020	659	916	43,007
2013	11,155	28,003	705,044	644	928	41,449
2013 Board Approved	11,635	30,044	630,659	657	888	41,566
2014	10,890	27,467	671,214	645	847	40,030
2015	10,326	27,429	671,704	643	812	42,739
2016	9,867	27,326	700,789	635	555	43,533
2017 Bridge	9,877	27,303	700,703	627	299	51,786
2018 Test	9,950	27,393	703,899	627	299	51,416

2.3.1.1 Multivariate Regression Model

PUC Distribution's weather normalized load forecast is developed in a three-step process. First, a total system weather normalized purchased forecast is developed based on a regression analysis that incorporates variables that impact PUC Distribution usage. Second, the weather normalized purchased forecast is adjusted by a historical loss factor to produce a weather normalized billed forecast. Finally, the forecast of billed energy by rate class is developed based on a forecast of customer numbers and historical usage patterns per customer. For the rate classes that have weather sensitive load, their forecasted billed energy is adjusted to ensure that the total billed energy forecast by rate class is equivalent to the total weather normalized billed energy forecast. The forecast of customers by rate class is determined using a geometric mean analysis and judgment of PUC Distribution. The forecast is also adjusted for expected CDM results. For those rate classes that use kW for the distribution volumetric billing determinant an adjustment factor is applied to the class energy forecast based on the historical relationship between kW and kWh. The following will explain the forecasting process in more detail.

Purchased KWh Load Forecast

An equation to predict total system purchased energy is developed using a multivariate regression model with independent variables outlined below. The regression model uses monthly kWh and monthly values of independent variables from January 2003 to December 2016 to determine the monthly regression coefficients. This provides 168 monthly data points which are a reasonable data set for use in a multiple regression analysis.

With regards to weather normalization, PUC Distribution submits that it is appropriate to review the impact of weather over the past ten years January 2007 to December 2016 since it is consistent with the time period for weather normalization outlined in the filing requirements. It is also reflective of more recent weather conditions. The average weather conditions over this period are applied in the prediction formula to determine a weather normalized forecast. In accordance with the filing requirement, PUC

Distribution has also provided sensitivity analysis showing the impact on the 2018 forecast of purchases. This analysis assumes weather normal conditions are based on a 20 year trend of weather data.

The multivariate regression model has determined drivers of year-over-year changes in PUC Distribution's load growth are weather (heating and cooling degree days), calendar variables (days in month and seasonal flag), number of customers and CDM activity. These factors are captured within the multivariate regression model.

Weather impacts on load are apparent in both the winter heating season, and in the summer cooling season. For that reason, both Heating Degree Days (i.e. a measure of coldness in winter) and Cooling Degree Days (i.e. a measure of summer heat) are modeled.

Other factors determining energy use in the monthly model are the number of days in a particular month and a flag that indicates spring and fall months.

The regression analysis also indicates that the number of customers and CDM activity are significant contributors to the total energy used in the PUC Distribution service area.

The following outlines the predication model used by PUC Distribution to predict weather normal purchases for 2017 and 2018. The 2017 and 2018 weather normal purchases have been adjusted to include the impact of reduced consumption from the recent installation of new street lights. On a billed energy basis the average historical annual kWh for street lights from 2003 to 2016, of 7,437,417 kWh has been reduced to 2,415,793 kWh for 2017 and 2018 to reflect the consumption of the new energy efficient street lights installed during 2016 in the PUC Distribution service area. The reduction in billed consumption of 5,021,624 (i.e. 7,437,417 minus 2,415,793) times the loss factor, explained below, of 1.0459 has been applied to the 2017 and 2018 forecast of weather normal purchases. This is an adjustment of 5,252,259 kWh for both years.

PUC Distribution Monthly Predicted kWh Purchases

= Heating Degree Days * 39,811
+ Cooling Degree Days * 84,271
+ Spring Fall Flag * (2,894,992)
+ Number of Days in the Month * 1,815,877
+ CDM Activity * (3.68)
+ Number of Customers * 2,620
+ Constant of (92,792,690)
- 5,252,259 for street lights

The monthly data used in the regression model and the resulting monthly prediction for the actual and forecasted years are provided in Appendix 1.

The sources of data for the various data points are:

a) The Environment Canada website provided the monthly heating degree day and cooling degree information. Weather data from the Sault Ste. Marie Weather Station was used. 18° C is the base numbers from which heating degree days and cooling degree days are measured.

b) The calendar provided information related to number of days in the month and the months defined to be spring or fall (i.e. March to May and September to November).

c) PUC Distribution's billing system provided the customer data.

d) The CDM activity variable is an estimated level of monthly activity in CDM for the years 2006 to 2018 for all verified savings from 2006 to 2016 programs including their persistence. For each year the monthly values grow at constant value over the year. The addition of the monthly values will equal the total annual CDM results shown in the table below. In the first year of the program the half year rule is applied. The following table supports the level of annual CDM results and provides the source of the annual program and persistence data by year which was used to develop the monthly values shown in Appendix 1.

Table 3-6: CDM Activity Variable Supporting Data

Year	OPA Annual CDM Final Results 2006 to 2010 programs (kWh)	OPA/IESO Annual CDM Final Results 2011 to 2014 programs (kWh)	IESO Annual Final CDM Results 2015 programs (kWh)	IESO Annual Final CDM Results 2016 programs (kWh)	Total Annual CDM Results (kWh)
2006	1,571,522	0	0	0	1,571,522
2007	4,551,504	0	0	0	4,551,504
2008	6,625,849	0	0	0	6,625,849
2009	8,277,544	0	0	0	8,277,544
2010	7,031,262	0	0	0	7,031,262
2011	6,681,180	2,252,978	0	0	8,934,158
2012	6,429,476	5,995,033	0	0	12,424,509
2013	6,368,225	7,754,369	0	0	14,122,594
2014	5,978,749	13,124,709	0	0	19,103,457
2015	4,582,235	14,272,201	2,700,374	0	21,554,810
2016	3,917,535	13,893,402	5,259,083	4,409,060	27,479,080
2017	3,161,652	11,963,920	5,227,909	8,793,170	29,146,651
2018	2,827,981	11,022,261	5,222,016	8,793,170	27,865,428

The prediction formula has the following statistical results (Table 3-7) which generally indicate the formula has a very good fit to the actual data set.

Table 3-7: Statistical Results

R Square	96.5%
Adjusted R Square	96.4%
F Test	745.1
MAPE (Monthly)	2.6%
T-stats by Coefficient	
Heating Degree Days	50.7
Cooling Degree Days	5.8
Spring Fall Flag	(7.4)
Number of Days in Month	8.6
CDM Activity	(6.6)
Number of Customers	3.1
Constant	(3.3)

The annual results of the above prediction formula compared to the actual annual purchases from 2003 to 2016 are shown below in Table 3-8 along with the predicted total system purchases for PUC Distribution for 2017 and 2018 on a weather normal basis. In addition, weather normal values for 2018 are provided on a 20 year trend assumption for weather normalization. Information is also provided to show the Weather Normal Conversion Factor which is used to weather normalize actual volume data. In Table 3-8, the Predicted Weather Normal values are similar to the Predicted amounts but the weather normalized heating degree days and cooling degree days used to determine the weather normal forecast for 2017 and 2018 are used in the prediction formula in place of actual heating degree days and cooling degree days. The ratio of Predicted Weather Normal to Predicted values results in a Weather Normal Conversion Factor. This factor is applied to the Actual amount which results in the Actual Weather Normal value.

Table 3-8: Total System Purchase

Year	Actual	Predicted	% Difference	Predicted Weather Normal	Weather Normal Conversion Factor	Actual Weather Normal
Purchased Energy (GWh)						
2003	755.1	755.4	0.0%	740.6	0.9804	740.3
2004	757.7	753.0	(0.6%)	743.7	0.9876	748.3
2005	749.2	751.2	0.3%	745.7	0.9927	743.7
2006	728.1	729.2	0.2%	742.4	1.0181	741.3
2007	738.1	734.2	(0.5%)	731.6	0.9964	735.5
2008	741.0	741.0	0.0%	731.6	0.9873	731.6
2009	732.9	738.4	0.7%	729.5	0.9880	724.1
2010	714.2	730.4	2.3%	739.7	1.0127	723.3
2011	745.0	735.5	(1.3%)	736.6	1.0014	746.1
2012	707.0	694.7	(1.7%)	727.8	1.0477	740.7
2013	730.6	715.4	(2.1%)	726.3	1.0152	741.7
2014	730.5	737.6	1.0%	707.8	0.9596	701.0
2015	698.5	711.3	1.8%	699.5	0.9834	686.9
2016	670.0	670.5	0.1%	678.6	1.0121	678.1
2017 Bridge		672.0		672.0	1.0000	
2018 Test		678.0		678.0	1.0000	
2018 - 20 year trend		682.6		682.6	1.0000	

The weather normalized amount for 2018 is determined by using 2018 dependent variables in the prediction formula on a monthly basis along with the average monthly heating degree days and cooling degree days which have occurred from January 2007 to December 2016 (i.e. 10 years). The 2018 weather normal 20 year trend value reflects the trend in monthly heating degree days and cooling degree days which have occurred from January 1997 to December 2016.

Billed KWh Load Forecast

To determine the total weather normalized energy billed forecast, the total system weather normalized purchases forecast is adjusted by a historical loss factor. The historical loss factor used is 4.59% which represents the average loss factor from 2003 to 2016. With this average loss factor the total weather normalized billed energy before the adjustment discussed below will be 642.5 (GWh) for 2017 (i.e. 672.0/1.0459) and 648.2 (GWh) for 2018 (i.e. (i.e. 678.0/1.0459).

Billed KWh Load Forecast and Customer/Connection Forecast by Rate Class

Since the total weather normalized billed PUC Distribution amount is known this amount needs to be distributed by rate class for rate design purposes taking into consideration the customer/connection forecast and expected usage per customer by rate class.

The next step in the forecasting process is to determine a customer/connection forecast. The customer/connection forecast is based on reviewing historical customer/connection data that is available as shown in the following Table 3-9.

Table 3-9: Historical Customer/Connection Data

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Sentinel Lighting	Street Lights	Unmetered Scattered Load	Total
Number of Customers/Connections							
2003	28,544	3,230	419	466	8,619	12	41,290
2004	28,560	3,247	424	466	8,635	19	41,351
2005	28,576	3,274	431	459	8,642	27	41,409
2006	28,596	3,301	432	449	8,663	28	41,469
2007	28,630	3,302	429	443	8,707	27	41,538
2008	28,780	3,325	426	435	8,741	22	41,729
2009	28,971	3,352	433	423	8,799	17	41,995
2010	29,057	3,345	435	411	8,846	16	42,110
2011	29,124	3,366	403	402	8,846	19	42,160
2012	29,197	3,383	401	395	8,875	20	42,271
2013	29,271	3,401	399	387	8,904	21	42,383
2014	29,514	3,464	370	362	8,846	21	42,577
2015	29,566	3,431	373	360	8,839	21	42,590
2016	29,620	3,414	361	362	8,872	21	42,650

From the historical customer/connection data the growth rate in customer/connection can be evaluated which is provided on the following Table 3-10.

Table 3-10: Growth Rate in Customer/Connections

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Sentinel Lighting	Street Lights	Unmetered Scattered Load
Growth Rate in Customers/Connections						
2003						
2004	0.1%	0.5%	1.2%	0.0%	0.2%	58.3%
2005	0.1%	0.8%	1.7%	(1.5%)	0.1%	42.1%
2006	0.1%	0.8%	0.2%	(2.2%)	0.2%	3.7%
2007	0.1%	0.0%	(0.7%)	(1.3%)	0.5%	(3.6%)
2008	0.5%	0.7%	(0.7%)	(1.8%)	0.4%	(18.5%)
2009	0.7%	0.8%	1.6%	(2.8%)	0.7%	(22.7%)
2010	0.3%	(0.2%)	0.5%	(2.8%)	0.5%	(5.9%)
2011	0.2%	0.6%	(7.4%)	(2.2%)	0.0%	18.8%
2012	0.7%	2.4%	(9.2%)	(2.5%)	0.0%	10.5%
2013	0.6%	0.8%	1.9%	(4.6%)	0.0%	0.0%
2014	0.0%	(0.3%)	(0.8%)	(3.2%)	0.0%	0.0%
2015	0.2%	(1.0%)	0.8%	(0.6%)	(0.1%)	0.0%
2016	0.2%	(0.5%)	(3.2%)	0.6%	0.4%	0.0%
Geometric Mean	0.3%	0.4%	(1.1%)	(1.9%)	0.2%	4.4%

The geometric mean was determined for each rate class to reflect the average growth rate from 2003 to 2016.

The geometric mean analysis was used to forecast the number of customers/connections for 2017 and 2018. The results of the geometric mean analysis were applied to the 2016 customer/connection value to determine the 2017 customer/connection forecast. The 2018 customer/connection forecast is determined by applying the geometric mean factor to the 2017 forecast. Table 3-11 outlines the forecast of customers/connections by rate class.

Table 3-11: Customer/Connection Forecast

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Sentinel Lighting	Street Lights	Unmetered Scattered Load	Total
Forecast Number of Customers/Connections							
2017 Bridge	29,704	3,429	357	355	8,070	22	41,937
2018 Test	29,789	3,443	353	348	8,070	23	42,026

The next step in the process is to review the historical customer/connection usage and to reflect this usage per customer in the forecast. Table 3-12 below provides the average annual usage per customer by rate class for 2016.

Table 3-12: 2016 Actual Annual Usage per Customer

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Sentinel Lighting	Street Lights	Unmetered Scattered Load
Annual kWh Usage Per Customer/Connection						
2016	9,748	26,999	692,397	627	549	43,012

The 2017 and 2018 forecast of usage per customer/connection have been held constant at the 2016 level since as observed in Table 3-5 the usage per customer/connection has generally been declining since 2008. To continue this declining pattern into the 2017 and 2018 could cause double counting of CDM results when a manual adjustment for CDM is applied to 2017 and 2018 later on in the process. The resulting usage forecast is as follows in Table 3-13.

Table 3-13: Forecast Annual kWh Usage per Customer/Connection

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Sentinel Lighting	Street Lights	Unmetered Scattered Load
Forecast Annual kWh Usage per Customers/Connection						
2017 Bridge	9,748	26,999	692,397	627	549	43,012
2018 Test	9,748	26,999	692,397	627	549	43,012

Except for the Street Lights and Unmetered Scattered Load classes, the preceding information is used to determine the non-normalized weather billed energy forecast by applying the forecast number of customer/connection from Table 3-11 by the forecast of annual usage per customer/connection from Table 3-13. For Street Lights, the value represents the known 2017 annual kW of 7,076 kW divided by the 2016 kW/kWh ratio of 0.2929%. For Unmetered Scattered Load, it is the forecasted number of customer from Table 3-11 times the forecast of annual usage per customer/connection from Table 3-13 plus an adjustment of 192,360 kWh for traffic lights. This amount had not been previously included in the kWh for the Unmetered Scattered Load class. The resulting non-normalized weather billed PUC Distribution forecast is shown in the following Table 3-14.

Table 3-14: Non-normalized Weather Billed PUC Distribution Forecast

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Sentinel Lighting	Street Lights	Unmetered Scattered Load	Total
NON-normalized Weather Billed Energy Forecast (GWh)							
2017 Bridge	289.6	92.6	247.1	0.2	2.4	1.1	633.0
2018 Test	290.4	93.0	244.3	0.2	2.4	1.2	631.5

The non-normalized weather billed energy forecast has been determined but it needs to be adjusted in order to be aligned with the total weather normalized billed energy forecast. As previously determined, the total weather normalized billed energy forecast is 642.5 (GWh) for 2017 and 648.2 (GWh) for 2018.

The difference between the non-normalized and normalized forecast adjustments is 9.5 GWh in 2017 (i.e. 642.5 – 633.0) and 16.7 GWh in 2018 (i.e. 648.2 – 631.5). The difference is assumed to be the adjustment needed to move the forecast to a weather normal basis and this amount will be assigned to those rate classes that are weather sensitive. Based on the weather normalization work completed by Hydro One for PUC Distribution for the cost allocation study, which has been used to support this Application, it was determined that the weather sensitivity by rate classes is as follows in Table 3-15.

Table 3-15: Weather Sensitivity by Rate Class

Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Sentinel Lighting	Street Lights	Unmetered Scattered Load
Weather Sensitivity					
92.7%	92.7%	85.3%	0.0%	0.0%	0.0%

For the GS > 50 kW class the weather sensitivity amount of 85.3% was provided in the weather normalization work completed by Hydro One. For the Residential and General Service < 50 kW classes, it was assumed in the 2013 COS application that the weather sensitivity for the Residential and General Service < 50 kW classes was mid-way between 100% and 85.3%, or 92.7%. This assumption has been maintained in this application.

The difference between the non-normalized and normalized forecast of 9.5 GWh in 2017 and 16.7 GWh in 2018 has been assigned on a pro rata basis to each rate class based on the above level of weather sensitivity.

2.3.1.2 Normalized Average use per Customer ("NAC") Model

PUC Distribution did not use this methodology.

2.3.1.3 CDM Adjustment and LRAMVA

A manual adjustment has been made to reflect the impact of 2017 to 2018 CDM programs on the load forecast. PUC Distribution has made this adjustment to reflect the "net" impact of the CDM programs on the load forecast.

The following Table 3-16, outlines the expected full year savings from 2017 to 2018 CDM programs based on the projected CDM savings for PUC Distribution. It is assumed that the savings that occur for the 2017 program in 2017 will persist at 99.7% in 2018 which is consistent with the persistence of 2016 programs into 2017.

Table 3-16: 2017 to 2018 Expected Full Year Total kWh Savings

	2017	2018
2017 Programs	3,375,904	3,366,352
2018 Programs		3,913,998
Total Including Persistence	3,375,904	7,280,350

The following outlines how the above information is assigned to rate class.

Table 3-17: 2017 to 2018 Expected Full Year Residential kWh Savings

	2017	2018
2017 Programs	1,400,602	1,396,639
2018 Programs		1,189,716
Total Including Persistence	1,400,602	2,586,355

Table 3-18: 2017 to 2018 Expected Full Year GS < 50 kW kWh Savings

	2017	2018
2017 Programs	802,685	800,414
2018 Programs		802,685
Total Including Persistence	802,685	1,603,099

Table 3-19: 2017 to 2018 Expected Full Year GS > 50 kW kWh Savings

	2017	2018
2017 Programs	1,172,617	1,169,299
2018 Programs		1,921,597
Total Including Persistence	1,172,617	3,090,896

Since the regression analysis is based on actual power purchased data up to and including 2016 actual data, it is assumed that any savings from programs initiated up to and including 2016 are reflected in the prediction equation on a full year basis since the CDM Activity variable is used in the prediction formula. It is also assumed the savings in the first year of the program will be occur evenly over the year which means the actual impact on the load forecast will be one half of the full year results in the first year of the program. This has been classified as the half year rule for CDM purposes. As a result, consistent with the approach used in previous COS applications the following table outlines the total manual CDM adjustment for 2017 and 2018.

Rate class CDM adjustment 2017 = 2017 Programs rate class savings x 50%.

Rate class CDM adjustment 2018 = 2017 Programs rate class persistence savings + 2018 Programs rate class savings x 50%.

The following table outlines the CDM adjustment by rate class.

Table 3-20: Manual CDM Adjustment by Rate Class (kWh)

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Total
2017 Bridge	700,301	401,343	586,308	1,687,952
2018 Test	1,991,497	1,201,757	2,130,097	5,323,351

In accordance with the Guidelines for Electricity Distributor Conservation and Demand Management (EB-2013-0003), issued April 26, 2013 (“CDM Guidelines”), it is PUC Distribution’s understanding that as part of this application expected CDM savings in 2018 from 2017 and 2018 programs will need to be established for lost revenue adjustment mechanism (“LRAM”) variance accounts purposes. PUC Distribution also understands that the IESO will measure CDM results on a full year net basis.

Consistent with past practices, it is expected the full year net level of savings will be used for LRAM variance calculations. As a result, it is PUC Distribution's view the units used for the LRAM variance account should also be on a full year net basis. Based on the evidence provided above in regards to the CDM manual adjustment the following equation is used to determine the rate class kWh assumed in the load forecast for LRAM variance account purposes

Rate class LRAMVA Threshold 2018 = Rate class 2017 Program Persistence savings + Rate class 2018 Program savings. The conversion to kW for the GS > 50 kW class uses the kW/kWh factor from Table 3-24.

<u>Table 3-21: 2018 Expected CDM Savings by Rate Class for LRAM Variance Account</u>

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Total
2018 Test - kWh	2,586,355	1,603,099	3,090,896	7,280,350
2018 Test - kW Annual			7,708	7,708
2018 Test - kW Monthly			642	642

The following Table 3-22 outlines how the classes have been adjusted to align the non-normalized forecast with the normalized forecast and reflect the adjustments discussed above.

Table 3-22: Alignment of Non-normal to Weather Normal Forecast

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Sentinel Lighting	Street Lights	Unmetered Scattered Load	Total
Non-normalized Weather Billed Energy Forecast (GWh)							
2017 Bridge	289.6	92.6	247.1	0.2	2.4	1.1	633.0
2018 Test	290.4	93.0	244.3	0.2	2.4	1.2	631.5
Weather Adjustment (GWh)							
2017 Bridge	4.5	1.4	3.6	0.0	0.0	0.0	9.5
2018 Test	8.0	2.6	6.2	0.0	0.0	0.0	16.7
CDM Adjustment (GWh)							
2017 Bridge	(0.7)	(0.4)	(0.6)				(1.7)
2018 Test	(2.0)	(1.2)	(2.1)				(5.3)
Weather Normalized Billed Energy Forecast (GWh)							
2017 Bridge	293.4	93.6	250.1	0.2	2.4	1.1	640.8
2018 Test	296.4	94.3	248.3	0.2	2.4	1.2	642.9

Billed KW Load Forecast

There are three rate classes that charge volumetric distribution on per kW basis. These include General Service 50 to 4,999 kW, Sentinel Lights and Street Lights. The forecast of kW for General Service 50 to 4,999 kW and Sentinel Lights classes is based on a review of the historical ratio of kW to kWh and applying the average ratio to the forecasted kWh to produce the required kW. For Street Lights, the forecasted kW for 2017 and 2018 is based on the known information for 2017 reflecting the new energy efficient street lights installed in 2016

The following Table 3-23 outlines the annual demand units by applicable rate class on actual and weather normal basis. The weather normal values are actual values adjusted by the weather normal conversion factor outlined in Table 3-8. PUC Distribution is uncertain if this weather normalization adjustment is the appropriate adjustment to weather normalize monthly kW but it has been done to be consistent with the weather normalization adjustment used for kWh.

Table 3-23: Historical Annual kW per Applicable Rate Class

Year	General Service 50 to 4,999 kW	Sentinel Lighting	Street Lights	Total	General Service 50 to 4,999 kW	Sentinel Lighting	Street Lights	Total
Billed Annual kW								
	Actual				**Weather Normal**			
2003	659,827	768	21,295	681,890	646,896	753	20,878	668,527
2004	673,069	873	21,340	695,282	664,744	862	21,076	686,682
2005	682,195	784	21,295	704,274	677,194	778	21,139	699,111
2006	657,827	766	23,029	681,622	669,741	780	23,446	693,967
2007	657,184	747	21,406	679,337	654,849	744	21,330	676,923
2008	650,699	744	21,317	672,760	642,457	735	21,047	664,239
2009	637,622	730	21,346	659,698	629,974	721	21,090	651,785
2010	635,104	714	23,264	659,082	643,193	723	23,560	667,476
2011	629,024	703	21,619	651,346	629,915	704	21,650	652,268
2012	627,836	687	21,596	650,119	657,810	720	22,627	681,156
2013	656,137	660	21,588	678,385	666,098	670	21,916	688,683
2014	634,289	676	21,876	656,841	608,657	649	20,992	630,298
2015	711,311	752	21,794	733,857	699,477	739	21,431	721,648
2016	622,066	630	14,262	636,959	629,606	638	14,435	644,679

The following Table 3-24 shows the historical ratio of kW/kWh as well as the average

Table 3-24: Historical kW/kWh Ratio per Applicable Rate Class

Year	General Service 50 to 4,999 kW	Sentinel Lighting	Street Lights
Ratio of kW to kWh			
2003	0.2502%	0.2777%	0.2961%
2004	0.2525%	0.2998%	0.2894%
2005	0.2564%	0.2786%	0.2759%
2006	0.2471%	0.2796%	0.3028%
2007	0.2528%	0.2776%	0.2803%
2008	0.2492%	0.2768%	0.2797%
2009	0.2462%	0.2781%	0.2808%
2010	0.2471%	0.2766%	0.3000%
2011	0.2457%	0.2700%	0.2766%
2012	0.2469%	0.2787%	0.2791%
2013	0.2533%	0.2781%	0.2669%
2014	0.2451%	0.2778%	0.2800%
2015	0.2792%	0.3197%	0.2987%
2016	0.2489%	0.2775%	0.2929%
Average 2003 to 2016	0.2515%	0.2819%	0.2857%
Used for Forecast	0.2515%	0.2819%	Reflects 2017 actual

The following Table 3-25 outlines the forecast of kW for the applicable rate classes.

Table 3-25: kW Forecast by Applicable Rate Class

Year	General Service 50 to 4,999 kW	Sentinel Lighting	Street Lights	Total
Predicted Billed kW				
2017 Bridge	628,830	628	7,076	636,534
2018 Test	624,500	616	7,076	632,192

Table 3-26 provides a summary of the total load forecast on a power purchased and billed level from 2013 Board Approved to 2018 Test.

Table 3-26: Summary of Total Load Forecast

	2013 Board Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge Weather Normal	2018 Test Weather Normal
Purchases							
Actual kWh Purchases		730,568,311	730,490,285	698,517,377	669,958,462		
Predicted kWh Purchases before CDM		715,403,222	737,634,264	711,332,613	670,476,629	672,043,983	677,967,857
% Difference between actual and predicted purchases		(2.1%)	1.0%	1.8%	0.1%		
Loss Factor						1.0459	1.0459
Total Billed Before CDM Adjustments						642,533,500	648,197,248
CDM Adjustment						1,687,952	5,323,351
Total Billed After Adjustments		688,244,167	701,843,127	669,387,526	636,876,244	640,845,548	642,873,897
Billing Determinants							
Residential							
Customers	29,271	29,504	29,514	29,566	29,620	29,704	29,789
kWh	340,561,449	324,185,392	334,950,383	310,458,240	288,746,486	293,388,553	296,393,596
General Service < 50 kW							
Customers	3,401	3,474	3,464	3,431	3,414	3,429	3,443
kWh	102,179,766	95,827,695	99,153,426	95,701,162	92,174,996	93,612,036	94,320,130
General Service 50 to 4,999 kW							
Customers	399	373	370	373	361	357	353
kWh	251,632,820	259,048,750	258,807,830	254,784,565	249,955,178	250,071,137	248,349,153
kW	628,286	656,137	634,289	711,311	622,066	628,830	624,500
Sentinel Lighting							
Connections	387	374	362	360	362	355	348
kWh	254,165	237,315	243,349	235,238	227,056	222,688	218,403
kW	710	660	676	752	630	628	616
Street Lights							
Connections	8,904	8,846	8,846	8,839	8,872	8,070	8,070
kWh	7,907,160	8,087,592	7,812,115	7,295,612	4,869,277	2,415,793	2,415,793
kW	22,680	21,588	21,876	21,794	14,262	7,076	7,076
Unmetered Scattered Load							
Connections	21	21	21	21	21	22	23
kWh	872,889	857,423	876,024	912,709	903,251	1,135,342	1,176,822
Total							
Customer/Connections	42,383	42,592	42,577	42,590	42,650	41,937	42,026
kWh	703,408,249	688,244,167	701,843,127	669,387,526	636,876,244	640,845,548	642,873,897
kW from applicable classes	651,676	678,385	656,841	733,857	636,959	636,534	632,192

2.3.2 Accuracy of Load Forecast and Variance Analyses

The following discussion provides a year over year variance analysis on PUC Distribution's distribution revenue and billing determinants. The variance analysis will compare 2013 Board Approved to 2013 Actual; 2013 Actual to 2014 Actual; 2014 Actual to 2015 Actual; 2015 Actual to 2016 Actual; 2016 Actual to 2017 Bridge and 2017 Bridge Year to 2018 Test Year. The distribution revenue variance analysis is based on information provided in Table 3-1. The billing determinant variance analysis is based on data outlined in Table 3-26. The overall variance analysis has been provided based on PUC Distribution's materiality of $110,400; the materiality calculation being noted earlier in Exhibit 1 of this Application.

2013 Board Approved vs. 2013 Actual

Table 3-27: Distribution Revenue - 2013 Board Approved vs 2013 Actual

Distribution Throughput Revenue	2013 Board Approved	2013 Actual	Difference $	Difference %
Residential	9,069,512.00	8,383,231.09	(686,280.91)	-8%
General Service <50 kW	2,664,966.00	2,479,550.11	(185,415.89)	-7%
General Service 50 to 4,999 kW	3,725,714.00	3,723,727.25	(1,986.75)	0%
Sentinel Lighting	31,753.00	28,613.17	(3,139.83)	-10%
Street Lighting	720,198.00	663,165.82	(57,032.18)	-8%
Unmetered Scattered Load	29,206.00	27,443.00	(1,763.00)	-6%
Total	**16,241,349.00**	**15,305,730.44**	**(935,618.56)**	**-6%**

Throughput revenue for 2013 was $935,619 or 6.0% lower than the amounts approved in the 2013 Cost of Service due to the revised rates not being in effect for the full year (July 1)

Table 3-28: Billing Determinants – 2013 Board Approved vs 2013 Actual

Billing Quantiites	**Customers / Connections**		**Units**	**Volume**		**Volume Weather Normal**		**Annual Usage Per Customer / Connection**		**Annual Usage Per Customer / Connection Weather Normal**	
Weather Normal Conversion Factor							1.0152				
	2013 Board Approved	2013 Actual		2013 Board Approved	2013 Actual	2013 Board Approved	2013 Actual	2013 Board Approved	2013 Actual	2013 Board Approved	2013 Actual
Residential	29,271	29,504	kWh	340,561,449	324,185,392	340,561,449	329,106,723	11,635	10,988	11,635	11,155
General Service < 50 kW	3,401	3,474	kWh	102,179,766	95,827,695	102,179,766	97,282,417	30,044	27,584	30,044	28,003
General Service 50 to 4,999 kW	399	373	kW	628,286	656,137	628,286	666,098	1,575	1,759	1,575	1,786
Sentinel Lighting	387	374	kW	710	660	710	670	2	2	2	2
Street Lights	8,904	8,846	kW	22,680	21,588	22,680	21,916	3	2	3	2
Unmetered Scattered Load	21	21	kWh	872,889	857,423	872,889	870,439	41,566	40,830	41,566	41,449
Total	42,383	42,592									
	Variance			Variance		Variance		Variance		Variance	
Residential	233		kWh	(16,376,057)		(11,454,726)		(647)		(480)	
General Service < 50 kW	73		kWh	(6,352,071)		(4,897,349)		(2,460)		(2,041)	
General Service 50 to 4,999 kW	(26)		kW	27,851		37,812		184		211	
Sentinel Lighting	(13)		kW	(50)		(40)		(0)		(0)	
Street Lights	(58)		kW	(1,092)		(764)		(0)		(0)	
Unmetered Scattered Load	0		kWh	(15,466)		(2,450)		(736)		(117)	

When comparing the 2013 actual results to the 2013 board approved amounts the customer/connection forecast for 2013 was fairly consistent with 2013 actual values. Volume forecasts supporting the 2013 cost of service application were on the high side for the Residential and GS < 50 kW classes and on the low side for GS > 50 kW class.

2013 Actual vs. 2014 Actual

Table 3-29: Distribution Revenue – 2013 Actual vs 2014 Actual

Distribution Throughput Revenue	**2013 Actual**	**2014 Actual**	**Difference $**	**Difference %**
Residential	8,383,231.09	9,058,873.42	675,642.33	8%
General Service <50 kW	2,479,550.11	2,662,132.09	182,581.98	7%
General Service 50 to 4,999 kW	3,723,727.25	3,753,659.93	29,932.68	1%
Sentinel Lighting	28,613.17	31,254.59	2,641.42	9%
Street Lighting	663,165.82	702,906.23	39,740.41	6%
Unmetered Scattered Load	27,443.00	29,446.14	2,003.14	7%
Total	**15,305,730.44**	**16,238,272.40**	**932,541.96**	**6%**

The 2014 throughput revenue was $932,542 or 6.0% higher than 2013 actual revenue due to the increase in rates being in effect for the full year. The 2014 revenue is within $3,000 of the 2013 Board approved revenue.

Table 3-30: Billing Determinants - 2013 Actual vs 2014 Actual

Billing Quantiites	**Customers / Connections**		**Units**	**Volume**		**Volume Weather Normal**		**Annual Usage Per Customer / Connection**		**Annual Usage Per Customer / Connection Weather Normal**	
Weather Normal Conversion Factor						1.0152	0.9596				
	2013 Actual	2014 Actual		2013 Actual	2014 Actual	2013 Actual	2014 Actual	2013 Actual	2014 Actual	2013 Actual	2014 Actual
Residential	29,504	29,514	kWh	324,185,392	334,950,383	329,106,723	321,414,848	10,988	11,349	11,155	10,890
General Service < 50 kW	3,474	3,464	kWh	95,827,695	99,153,426	97,282,417	95,146,580	27,584	28,624	28,003	27,467
General Service 50 to 4,999 kW	373	370	kW	656,137	634,289	666,098	608,657	1,759	1,714	1,786	1,645
Sentinel Lighting	374	362	kW	660	676	670	649	2	2	2	2
Street Lights	8,846	8,846	kW	21,588	21,876	21,916	20,992	2	2	2	2
Unmetered Scattered Load	21	21	kWh	857,423	876,024	870,439	840,623	40,830	41,715	41,449	40,030
Total	42,592	42,577									
	Variance			Variance		Variance		Variance		Variance	
Residential	10		kWh	10,764,991		(7,691,875)		361		(264)	
General Service < 50 kW	(10)		kWh	3,325,731		(2,135,838)		1,040		(536)	
General Service 50 to 4,999 kW	(3)		kW	(21,848)		(57,441)		(45)		(141)	
Sentinel Lighting	(12)		kW	16		(21)		0		0	
Street Lights	0		kW	288		(924)		0		(0)	
Unmetered Scattered Load	0		kWh	18,601		(29,816)		886		(1,420)	

There is no material differences in the customer connections or usage per customer between 2013 and 2014.

2014 Actual vs. 2015 Actual

Table 3-31: Distribution Revenue - 2014 Actual vs 2015 Actual

Distribution Throughput Revenue	**2014 Actual**	**2015 Actual**	**Difference $**	**Difference %**
Residential	9,058,873.42	8,805,835.69	(253,037.73)	-3%
General Service <50 kW	2,662,132.09	2,636,670.63	(25,461.46)	-1%
General Service 50 to 4,999 kW	3,753,659.93	4,011,125.36	257,465.43	7%
Sentinel Lighting	31,254.59	28,967.18	(2,287.41)	-7%
Street Lighting	702,906.23	727,781.03	24,874.80	4%
Unmetered Scattered Load	29,446.14	30,918.73	1,472.59	5%
Total	**16,238,272.40**	**16,241,298.62**	**3,026.22**	**0%**

The 2015 throughput revenue was $3,026 or virtually unchanged from 2014.

Table 3-32: Billing Determinants - 2014 Actual vs 2015 Actual

Billing Quantiites	**Customers / Connections**		**Units**	**Volume**		**Volume Weather Normal**		**Annual Usage Per Customer / Connection**		**Annual Usage Per Customer / Connection Weather Normal**	
Weather Normal Conversion Factor						0.9596	0.9834				
	2014 Actual	2015 Actual		2014 Actual	2015 Actual	2014 Actual	2015 Actual	2014 Actual	2015 Actual	2014 Actual	2015 Actual
Residential	29,514	29,566	kWh	334,950,383	310,458,240	321,414,848	305,293,020	11,349	10,501	10,890	10,326
General Service < 50 kW	3,464	3,431	kWh	99,153,426	95,701,162	95,146,580	94,108,943	28,624	27,893	27,467	27,429
General Service 50 to 4,999 kW	370	373	kW	634,289	711,311	608,657	699,477	1,714	1,907	1,645	1,875
Sentinel Lighting	362	360	kW	676	752	649	739	2	2	2	2
Street Lights	8,846	8,839	kW	21,876	21,794	20,992	21,431	2	2	2	2
Unmetered Scattered Load	21	21	kWh	876,024	912,709	840,623	897,524	41,715	43,462	40,030	42,739
Total	42,577	42,590									
	Variance			Variance		Variance		Variance		Variance	
Residential	52		kWh	(24,492,143)		(16,121,828)		(848)		(564)	
General Service < 50 kW	(33)		kWh	(3,452,264)		(1,037,637)		(731)		(38)	
General Service 50 to 4,999 kW	3		kW	77,022		90,820		193		230	
Sentinel Lighting	(2)		kW	76		91		0		0	
Street Lights	(7)		kW	(82)		439		(0)		0	
Unmetered Scattered Load	0		kWh	36,685		56,901		1,747		2,710	

There is no material differences in the customer connections or usage per customer between 2014 and 2015.

2015 Actual vs. 2016 Actual

Table 3-33: Distribution Revenue - 2015 Actual vs 2016 Actual

Distribution Throughput Revenue	**2015 Actual**	**2016 Actual**	**Difference $**	**Difference %**
Residential	8,805,835.69	8,499,404.43	(306,431.26)	-3%
General Service <50 kW	2,636,670.63	2,537,808.73	(98,861.90)	-4%
General Service 50 to 4,999 kW	4,011,125.36	3,820,757.83	(190,367.53)	-5%
Sentinel Lighting	28,967.18	29,440.08	472.90	2%
Street Lighting	727,781.03	577,770.60	(150,010.43)	-21%
Unmetered Scattered Load	30,918.73	30,762.16	(156.57)	-1%
Total	**16,241,298.62**	**15,495,943.83**	**(745,354.79)**	**-5%**

The 2016 throughput revenue was $745,355 or 5% lower than the 2015 actual revenue primarily due to a reduction in kWh which can be attributed mainly to a milder year weather-wise.

Table 3-34: Billing Determinants - 2015 Actual vs 2016 Actual

Billing Quantiites	**Customers / Connections**		**Units**	**Volume**		**Volume Weather Normal**		**Annual Usage Per Customer / Connection**		**Annual Usage Per Customer / Connection Weather Normal**	
Weather Normal Conversion Factor						0.9834	1.0121				
	2015 Actual	2016 Actual		2015 Actual	2016 Actual	2015 Actual	2016 Actual	2015 Actual	2016 Actual	2015 Actual	2016 Actual
Residential	29,566	29,620	kWh	310,458,240	288,746,486	305,293,020	292,246,243	10,501	9,748	10,326	9,867
General Service < 50 kW	3,431	3,414	kWh	95,701,162	92,174,996	94,108,943	93,292,204	27,893	26,999	27,429	27,326
General Service 50 to 4,999 kW	373	361	kW	711,311	622,066	699,477	629,606	1,907	1,723	1,875	1,744
Sentinel Lighting	360	362	kW	752	630	739	638	2	2	2	2
Street Lights	8,839	8,872	kW	21,794	14,262	21,431	14,435	2	2	2	2
Unmetered Scattered Load	21	21	kWh	912,709	903,251	897,524	914,198	43,462	43,012	42,739	43,533
Total	42,590	42,650									
	Variance			Variance		Variance		Variance		Variance	
Residential	54		kWh	(21,711,754)		(13,046,778)		(752)		(459)	
General Service < 50 kW	(17)		kWh	(3,526,166)		(816,739)		(894)		(103)	
General Service 50 to 4,999 kW	(12)		kW	(89,245)		(69,871)		(184)		(131)	
Sentinel Lighting	2		kW	(122)		(102)		(0)		(0)	
Street Lights	33		kW	(7,532)		(6,996)		(1)		(1)	
Unmetered Scattered Load	0		kWh	(9,458)		16,675		(450)		794	

There is no material differences in the customer connections or usage per customer between 2015 and 2016. A drop in consumption as a result of milder weather conditions can be detected in the usage per customer.

2016 Actual vs. 2017 Bridge

Table 3-35: Distribution Revenue – 2016 Actual vs 2017 Bridge

Distribution Throughput Revenue	**2016 Actual**	**2017 Bridge**	**Difference $**	**Difference %**
Residential	8,499,404.43	9,020,207	520,802.31	6%
General Service <50 kW	2,537,808.73	2,660,109	122,299.98	5%
General Service 50 to 4,999 kW	3,820,757.83	4,011,695	190,937.31	5%
Sentinel Lighting	29,440.08	30,523	1,083.20	4%
Street Lighting	577,770.60	460,504	(117,266.96)	-20%
Unmetered Scattered Load	30,762.16	31,000	237.84	1%
Total	**15,495,943.83**	**16,214,037.51**	**718,093.68**	**5%**

Throughput revenue for 2017 is forecasted to be $$718,093 or 5% higher than 2016. The 2017 revenue is in line with prior years other than the low year of 2016..

Table 3-36: Billing Determinants - 2016 Actual vs 2017 Bridge

Billing Quantiites	**Customers / Connections**		**Units**	**Volume**		**Volume Weather Normal**		**Annual Usage Per Customer / Connection**		**Annual Usage Per Customer / Connection Weather Normal**	
Weather Normal Conversion Factor						1.0121	1.0000				
	2016 Actual	2017 Bridge		2016 Actual	2017 Bridge	2016 Actual	2017 Bridge	2016 Actual	2017 Bridge	2016 Actual	2017 Bridge
Residential	29,620	29,704	kWh	288,746,486	293,388,553	292,246,243	293,388,553	9,748	9,877	9,867	9,877
General Service < 50 kW	3,414	3,429	kWh	92,174,996	93,612,036	93,292,204	93,612,036	26,999	27,303	27,326	27,303
General Service 50 to 4,999 kW	361	357	kW	622,066	628,830	629,606	628,830	1,723	1,762	1,744	1,762
Sentinel Lighting	362	355	kW	630	628	638	628	2	2	2	2
Street Lights	8,872	8,070	kW	14,262	7,076	14,435	7,076	2	1	2	1
Unmetered Scattered Load	21	22	kWh	903,251	1,135,342	914,198	1,135,342	43,012	51,786	43,533	51,786
Total	42,650	41,937									
	Variance			Variance		Variance		Variance		Variance	
Residential	84		kWh	4,642,067		1,142,310		129		10	
General Service < 50 kW	15		kWh	1,437,040		319,831		304		(23)	
General Service 50 to 4,999 kW	(4)		kW	6,764		(776)		39		18	
Sentinel Lighting	(7)		kW	(2)		(10)		0		0	
Street Lights	(802)		kW	(7,186)		(7,359)		(1)		(1)	
Unmetered Scattered Load	1		kWh	232,092		221,144		8,774		8,253	

There is no material differences in the customer connections or usage per customer between 2016 and 2017.

2017 Bridge vs. 2018 Test

Table 3-37: Distribution Revenue - 2017 Bridge vs 2018 Test

Distribution Throughput Revenue	**2017 Bridge**	**2018 Test**	**Difference $**	**Difference %**
Residential	9,020,207	11,487,469	2,467,262.26	27%
General Service <50 kW	2,660,109	3,247,287	587,178.29	22%
General Service 50 to 4,999 kW	4,011,695	4,670,305	658,609.86	16%
Sentinel Lighting	30,523	35,771	5,247.72	17%
Street Lighting	460,504	203,298	(257,205.64)	-56%
Unmetered Scattered Load	31,000	47,454	16,454.00	53%
Total	**16,214,037.51**	**19,691,584.00**	**3,477,546.49**	**21%**

The proposed Test Year distribution revenue is a reflection of the 2018 COS application and the proposed base revenue requirement of $19,691,584. The variance in distribution revenue over the Bridge Year is a result of the proposed increases to fixed and variable distribution revenue in the Test Year.

Table 3-38: Billing Determinants - 2017 Bridge vs 2018 Test

Billing Quantiites	**Customers / Connections**		**Units**	**Volume**		**Volume Weather Normal**		**Annual Usage Per Customer / Connection**		**Annual Usage Per Customer / Connection Weather Normal**	
Weather Normal Conversion Factor						1.0000	1.0000				
	2017 Bridge	2018 Test		2017 Bridge	2018 Test	2017 Bridge	2018 Test	2017 Bridge	2018 Test	2017 Bridge	2018 Test
Residential	29,704	29,789	kWh	293,388,553	296,393,596	293,388,553	296,393,596	9,877	9,950	9,877	9,950
General Service < 50 kW	3,429	3,443	kWh	93,612,036	94,320,130	93,612,036	94,320,130	27,303	27,393	27,303	27,393
General Service 50 to 4,999 kW	357	353	kW	628,830	624,500	628,830	624,500	1,762	1,770	1,762	1,770
Sentinel Lighting	355	348	kW	628	616	628	616	2	2	2	2
Street Lights	8,070	8,070	kW	7,076	7,076	7,076	7,076	1	1	1	1
Unmetered Scattered Load	22	23	kWh	1,135,342	1,176,822	1,135,342	1,176,822	51,786	51,416	51,786	51,416
Total	41,937	42,026									
	Variance			Variance		Variance		Variance		Variance	
Residential	85		kWh	3,005,043		3,005,043		73		73	
General Service < 50 kW	15		kWh	708,094		708,094		90		90	
General Service 50 to 4,999 kW	(4)		kW	(4,330)		(4,330)		8		8	
Sentinel Lighting	(7)		kW	(12)		(12)		0		0	
Street Lights	0		kW	0		0		0		0	
Unmetered Scattered Load	1		kWh	41,479		41,479		(370)		(370)	

There is no material differences in the customer connections or usage per customer between 2016 and 2017.

2.3.3 Other Revenue

Variance Analysis of Other Revenue

Other Distribution Revenues are revenues that are distribution related but are sourced from means other than distribution rates. For this reason, other revenues are deducted from PUC Distribution's proposed revenue requirement. Further details on the derivation of the Revenue Requirement are presented at Exhibit 6.

Accounts used to record the revenues and associated costs are detailed in which corresponds to Board Appendix 2-N Shared Services and Corporate Cost Allocation is attached as Appendix 3.

PUC Distribution does not have any discrete customer groups that may be materially impacted by changes to other rates and charges.

Other Distribution revenues include such items as:

- Specific Service Charges

- Late Payment Charges

- Other Distribution Revenues

- Other Income and Expenses

Table 3-39: OEB Appendix 2-H Other Operating Revenue

A detailed breakdown by USoA account is shown below in Table 3-39 – OEB Appendix 2-H. Year over year variance analysis will follow with a discussion on those variances over $110,400.

Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2013 Actual[2]	2014 Actual[2]	2015 Actual[2]	2016 Actual[2]	Bridge Year	Test Year
		2013	2014	2015	2016	2017	2018
	Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
4080-2	SSS Revenue	$ 119,697	$ 119,614	$ 121,349	$ 118,839	$ 105,000	$ 105,000
4082	Retail Services Revenue	$ 29,639	$ 28,305	$ 27,321	$ 23,850	$ 23,500	$ 23,500
4084	STR Revenues	$ 470	$ 408	$ 360	$ 275	$ 300	$ 300
4210	Rent from Electric Property	$ 2,662,462	$ 1,609,979	$ 1,628,387	$ 1,731,777	$ 1,694,261	$ 1,719,261
4225	Late Payment Charges	$ 245,293	$ 270,758	$ 246,557	$ 177,225	$ 245,000	$ 259,000
4235	Miscellaneous Service Revenues	$ 247,215	$ 238,812	$ 291,424	$ 316,019	$ 170,100	$ 170,100
4305	Regulatory Debits	$ 43,830	$ -	$ -	$ -	$ -	$ -
4325	Revenues from Merchandise	$ 213,339	$ 83,547	$ 80,941	$ 229,685	$ 80,000	$ 80,000
4330	Costs & Expenses of Merchandising	-$ 7,548	-$ 8,212	-$ 12,050	-$ 2,507	-$ 12,653	-$ 7,500
4360	Loss on Disposition of Utility and Other Property	-$ 110,632	$ -	$ -	$ -	$ -	$ -
4375	Revenues of Non-Utility Operations	$ 1,381,145	$ 1,779,725	$ 1,110,897	$ 766,822	$ 1,537,447	$ 1,537,447
4380	Expenses of Non-Utility Operations	-$ 1,381,145	-$ 1,958,374	-$ 858,672	-$ 762,273	-$ 1,537,447	-$ 1,537,447
4390	Miscellaneous Non-Operating Income	$ 46,721	$ 21,014	$ 35,229	$ 19,338	$ -	$ 20,000
4405	Interest and Dividend Income	$ 41,984	$ 7,555	$ 26,460	$ 33,313	$ 20,500	$ 20,000
Specific Service Charges		$ 247,215	$ 238,812	$ 291,424	$ 316,019	$ 170,100	$ 170,100
Late Payment Charges		$ 245,293	$ 270,758	$ 246,557	$ 177,225	$ 245,000	$ 259,000
Other Operating Revenues		$ 2,812,268	$ 1,758,306	$ 1,777,417	$ 1,874,741	$ 1,823,061	$ 1,848,061
Other Income or Deductions		$ 227,694	-$ 74,745	$ 382,805	$ 284,378	$ 87,847	$ 112,500
Total		$ 3,532,470	$ 2,193,131	$ 2,698,203	$ 2,652,363	$ 2,326,008	$ 2,389,661

2013 Board Approved Comparison to 2013 Actual – Other Operating Revenue

Table 3-40 below summarizes the variance by account description followed by a discussion on those variances over $100,400.

Other Distribution Revenue	2013 Board Approved	2013 Actual	Difference $	Difference %
Specific Service Charges	232,090	247,215	15,125.00	7%
Late Payment Charges	250,000	245,293	(4,707.00)	-2%
Other Operating Revenues	1,848,340	2,812,268	963,928.00	52%
Other Income or Deductions	269,570	227,694	(41,876.00)	-16%
Total	**2,600,000.00**	**3,532,470.00**	**932,470.00**	**36%**

Other operating revenues for 2013 were 36% or $932,470 higher than the amounts approved in the 2013 Board Approved COS. Virtually the entire variance ($961,175) relates to the treatment of the new building usage fee. In the 2013 cost of service application 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 actual 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. The treatment was changed in the 2014 actual and onward to reflect the treatment in the cost of service rate application.

2013 Actual Comparison to 2014 Actual – Other Operating Revenue

Table 3-41 below summarizes the variance by account

Other Distribution Revenue	2013 Actual	2014 Actual	Difference $	Difference %
Specific Service Charges	247,215	238,812	(8,403.00)	-3%
Late Payment Charges	245,293	270,758	25,465.00	10%
Other Operating Revenues	2,812,268	1,758,306	(1,053,962.00)	-37%
Other Income or Deductions	227,694	(74,745)	(302,439.00)	-133%
Total	**3,532,470.00**	**2,193,131.00**	**(1,339,339.00)**	**-38%**

Other operating revenues for 2014 were 38% or $1,339,339 lower than the 2013 amount, again due mainly to the treatment of the new building usage fees ($1,034,574).

Other Income or deductions for 2014 were 133% or $302,439 lower than 2013 primarily because of an adjustment to reduce prior years CDM revenue by $178,649 and a reduction in jobbing revenue ($129,792) which is dependent on customer demand.

2014 Actual Comparison to 2015 Actual – Other Operating Revenue

Table 3-42 below summarizes the variance by account

Other Distribution Revenue	2014 Actual	2015 Actual	Difference $	Difference %
Specific Service Charges	238,812	291,424	52,612.00	22%
Late Payment Charges	270,758	246,557	(24,201.00)	-9%
Other Operating Revenues	1,758,306	1,777,417	19,111.00	1%
Other Income or Deductions	(74,745)	382,805	457,550.00	-612%
Total	**2,193,131.00**	**2,698,203.00**	**505,072.00**	**23%**

Other Income or Deductions for 2015 were 612% or $457,550 higher than 2014 due to the CDM adjustment in 2014 mentioned above and an additional CDM adjustment in 2015 which increased revenue by $252,224. The CDM adjustments account for $430,873 of the difference.

2015 Actual Comparison to 2016 Actual – Other Operating Revenue

Table 3-43 below summarizes the variance by account

Other Distribution Revenue	2015 Actual	2016 Actual	Difference $	Difference %
Specific Service Charges	291,424	316,019	24,595.00	8%
Late Payment Charges	246,557	177,225	(69,332.00)	-28%
Other Operating Revenues	1,777,417	1,874,741	97,324.00	5%
Other Income or Deductions	382,805	284,378	(98,427.00)	-26%
Total	**2,698,203.00**	**2,652,363.00**	**(45,840.00)**	**-2%**

Other Distribution Revenue is within 2% of prior year and there are no variances greater than materiality.

2016 Actual Comparison to 2017 Bridge – Other Operating Revenue

Table 3-44 below summarizes the variance by account

Other Distribution Revenue	2016 Actual	2017 Bridge	Difference $	Difference %
Specific Service Charges	316,019	170,100	(145,919.00)	-46%
Late Payment Charges	177,225	245,000	67,775.00	38%
Other Operating Revenues	1,874,741	1,823,061	(51,680.00)	-3%
Other Income or Deductions	284,378	87,847	(196,531.00)	-69%
Total	**2,652,363.00**	**2,326,008.00**	**(326,355.00)**	**-12%**

Specific Service Charges in 2017 are 46% ($145,919) less than 2016. Collection fees are projected to be $120,000 under prior year as a result in a change to collection processes. By utilizing an automated call system, PUC has substantially reduced the number of collection visits to customers' premises, therefore is no longer charging a collection charge in these circumstances.

Other Income or Deductions for 2017 are being projected at a 69% or $196,531 lower than 2016. Based on current year projections and the current economic outlook in PUC's service territory jobbing revenue, which is dependent on customer demand, is expected to be $149,685 less than prior year. Also based on current year projections, interest income will be $11,981 under prior year.

2017 Bridge Comparison to 2018 Test – Other Operating Revenue

Table 3-45 below summarizes the variance by account

Other Distribution Revenue	**2017 Bridge**	**2018 Test**	**Difference $**	**Difference %**
Specific Service Charges	170,100	170,100	-	0%
Late Payment Charges	245,000	259,000	14,000.00	6%
Other Operating Revenues	1,823,061	1,848,061	25,000.00	1%
Other Income or Deductions	87,847	112,500	24,653.00	28%
Total	**2,326,008.00**	**2,389,661.00**	**63,653.00**	**3%**

Other Distribution Revenue is within 3% of prior year and there are no variances greater than materiality.

Affiliate Transactions

PUC Distribution owns an integrated office/service centre building for which it receives a usage fee for a portion of building used by its affiliate PUC Services Inc. The fee, which is included in Other Operating Revenues (Account 4327), is based on a cost of capital charge and a depreciation charge and is prorated based on the portion of the building utilized by PUC Services. The method to determine fees is the same as that used by PUC Services in determining fees to PUC Distribution. A copy of the Management, Operations and Maintenance Agreement is included in Exhibit 4.

APPENDIX 1

Monthly Data Used For Regression Analysis

	Purchased kWh	Heating Degree Days	Cooling Degree Days	Spring Fall Flag	Number of Days in Month	CDM Activity	Number of Customers	Predicted Purchases
Jan-03	85,049,952	920.6	-	-	31.00	0	32,198	84,514,925
Feb-03	76,788,076	902.6	-	-	28.00	0	32,198	78,350,700
Mar-03	75,545,096	745.5	-	1.00	31.00	0	32,199	74,651,671
Apr-03	63,274,204	497.2	-	1.00	30.00	0	32,198	62,948,136
May-03	52,784,032	236.5	-	1.00	31.00	0	32,136	54,222,866
Jun-03	49,325,848	112.8	11.9	-	30.00	0	32,119	51,335,664
Jul-03	51,148,508	28.0	27.9	-	31.00	0	32,132	51,157,983
Aug-03	50,113,412	32.2	48.6	-	31.00	0	32,143	53,098,429
Sep-03	49,728,476	123.1	14.2	1.00	30.00	0	32,159	49,149,356
Oct-03	58,883,124	348.5	-	1.00	31.00	0	32,189	58,820,555
Nov-03	66,040,876	494.7	-	1.00	30.00	0	32,230	62,932,455
Dec-03	76,444,416	657.8	-	-	31.00	0	32,256	74,204,602
Jan-04	89,226,740	1,006.0	-	-	31.00	0	32,257	88,069,366
Feb-04	73,066,340	707.0	-	-	29.00	0	32,250	72,515,822
Mar-04	71,196,888	652.7	-	1.00	31.00	0	32,199	70,957,222
Apr-04	61,357,220	457.4	-	1.00	30.00	0	32,154	61,248,374
May-04	55,571,152	297.9	0.2	1.00	31.00	0	32,212	56,883,244
Jun-04	49,366,380	151.4	2.2	-	30.00	0	32,194	52,251,447
Jul-04	51,210,208	54.7	15.4	-	31.00	0	32,195	51,332,615
Aug-04	50,192,756	83.0	13.5	-	31.00	0	32,205	52,325,349
Sep-04	50,272,804	84.1	24.3	1.00	30.00	0	32,206	48,571,023
Oct-04	57,641,764	307.3	-	1.00	31.00	0	32,231	57,290,396
Nov-04	64,887,008	462.7	-	1.00	30.00	0	32,250	61,710,912
Dec-04	83,696,492	796.9	-	-	31.00	0	32,296	79,847,102
Jan-05	88,287,600	925.1	-	-	31.00	0	32,294	84,945,615
Feb-05	71,065,788	693.6	-	-	28.00	0	32,296	70,287,010
Mar-05	73,186,104	744.9	-	1.00	31.00	0	32,283	74,847,882
Apr-05	56,446,820	369.1	-	1.00	30.00	0	32,297	58,107,765
May-05	53,664,344	259.0	-	1.00	31.00	0	32,300	55,548,326
Jun-05	51,111,168	31.7	41.8	-	30.00	0	32,310	51,127,177
Jul-05	53,387,012	34.9	78.8	-	31.00	0	32,356	56,309,018
Aug-05	52,102,684	23.7	40.6	-	31.00	0	32,376	52,696,375
Sep-05	49,504,120	82.6	22.3	1.00	30.00	0	32,360	48,746,276
Oct-05	55,381,484	273.6	9.6	1.00	31.00	0	32,400	57,200,590
Nov-05	65,851,664	497.6	-	1.00	30.00	0	32,410	63,519,545
Dec-05	79,230,244	738.6	-	-	31.00	0	32,415	77,837,934
Jan-06	76,234,176	689.8	-	-	31.00	20,148	32,395	75,768,624
Feb-06	71,202,696	734.6	-	-	28.00	40,295	32,399	72,040,868
Mar-06	70,367,240	635.4	-	1.00	31.00	60,443	32,453	70,711,624
Apr-06	56,652,640	360.0	-	1.00	30.00	80,591	32,445	57,836,738
May-06	52,446,572	185.1	8.4	1.00	31.00	100,739	32,425	53,271,035
Jun-06	49,917,449	81.2	12.9	-	30.00	120,886	32,422	50,511,028
Jul-06	53,606,640	8.4	78.2	-	31.00	141,034	32,399	54,797,193
Aug-06	51,038,392	35.0	20.1	-	31.00	161,182	32,410	50,914,684
Sep-06	49,455,772	151.9	5.2	1.00	30.00	181,329	32,415	49,541,028
Oct-06	58,920,568	375.3	-	1.00	31.00	201,477	32,423	59,759,268
Nov-06	63,979,576	467.9	-	1.00	30.00	221,625	32,436	61,589,806
Dec-06	74,271,612	624.3	-	-	31.00	241,773	32,453	72,497,503

	Purchased kWh	Heating Degree Days	Cooling Degree Days	Spring Fall Flag	Number of Days in Month	CDM Activity	Number of Customers	Predicted Purchases
Jan-07	78,292,016	776.9	-	-	31.00	262,929	32,399	78,353,302
Feb-07	75,583,244	843.5	-	-	28.00	284,086	32,404	75,492,330
Mar-07	71,668,468	654.6	-	1.00	31.00	305,243	32,410	70,462,567
Apr-07	60,506,916	459.1	-	1.00	30.00	326,400	32,393	60,741,275
May-07	51,273,936	204.6	12.5	1.00	31.00	347,557	32,375	53,353,667
Jun-07	50,644,216	67.8	35.9	-	30.00	368,714	32,366	50,857,176
Jul-07	51,622,068	38.0	41.7	-	31.00	389,870	32,389	51,957,880
Aug-07	51,764,316	33.8	42.5	-	31.00	411,027	32,395	51,795,965
Sep-07	48,836,864	127.6	17.0	1.00	30.00	432,184	32,450	48,736,699
Oct-07	54,192,940	233.5	0.8	1.00	31.00	453,341	32,485	53,417,210
Nov-07	65,729,492	541.0	-	1.00	30.00	474,498	32,507	63,755,554
Dec-07	77,979,100	711.6	-	-	31.00	495,655	32,536	75,256,295
Jan-08	79,006,867	761.9	-	-	31.00	504,347	32,538	77,232,039
Feb-08	75,126,905	831.3	-	-	29.00	513,039	32,549	76,359,999
Mar-08	74,573,962	795.5	-	1.00	31.00	521,731	32,544	75,626,446
Apr-08	58,751,936	391.8	-	1.00	30.00	530,423	32,526	57,659,775
May-08	53,931,566	320.0	-	1.00	31.00	539,116	32,565	56,687,436
Jun-08	48,466,638	99.8	7.8	-	30.00	547,808	32,555	49,599,330
Jul-08	50,725,082	34.8	18.7	-	31.00	556,500	32,552	49,706,214
Aug-08	50,225,177	29.0	24.0	-	31.00	565,192	32,581	49,965,952
Sep-08	48,690,797	140.1	9.8	1.00	30.00	573,885	32,677	48,700,973
Oct-08	56,073,867	334.5	1.3	1.00	31.00	582,577	32,716	57,609,980
Nov-08	63,785,625	496.8	-	1.00	30.00	591,269	32,770	62,255,362
Dec-08	81,608,064	814.7	-	-	31.00	599,961	32,782	79,621,565
Jan-09	85,774,977	970.4	-	-	31.00	613,782	32,783	85,771,883
Feb-09	71,566,146	747.8	-	-	28.00	627,603	32,787	71,421,982
Mar-09	72,767,317	680.7	-	1.00	31.00	641,423	32,784	71,244,595
Apr-09	59,966,273	425.5	-	1.00	30.00	655,244	32,749	59,126,425
May-09	52,676,063	298.9	-	1.00	31.00	669,064	32,756	55,869,733
Jun-09	49,196,438	126.1	19.2	-	30.00	682,885	32,739	51,592,144
Jul-09	48,238,905	87.7	8.0	-	31.00	696,706	32,752	50,918,653
Aug-09	49,652,791	69.3	25.2	-	31.00	710,526	32,766	51,621,430
Sep-09	48,812,970	93.1	5.0	1.00	30.00	724,347	32,815	46,233,315
Oct-09	57,724,020	381.1	-	1.00	31.00	738,167	32,815	59,042,510
Nov-09	59,532,749	416.7	-	1.00	30.00	751,988	32,883	58,771,221
Dec-09	76,961,335	748.5	-	-	31.00	765,809	32,923	76,745,290
Jan-10	79,854,695	810.7	-	-	31.00	738,136	32,936	79,357,411
Feb-10	68,437,902	691.1	-	-	28.00	710,464	32,950	69,286,907
Mar-10	63,113,132	510.8	-	1.00	31.00	682,792	32,936	64,726,784
Apr-10	53,091,250	327.8	0.2	1.00	30.00	655,119	32,921	55,704,892
May-10	51,133,107	168.0	19.0	1.00	31.00	627,447	32,906	52,805,812
Jun-10	47,900,766	87.8	5.3	-	30.00	599,775	32,935	49,715,387
Jul-10	53,067,071	6.7	58.5	-	31.00	572,102	32,948	52,921,724
Aug-10	53,169,361	32.7	78.6	-	31.00	544,430	32,962	55,789,165
Sep-10	48,479,950	171.8	-	1.00	30.00	516,758	32,989	50,164,827
Oct-10	54,414,298	315.5	-	1.00	31.00	489,085	33,019	57,881,953
Nov-10	63,109,939	476.0	-	1.00	30.00	461,413	33,077	62,709,515
Dec-10	78,427,591	770.2	-	-	31.00	433,741	33,118	79,341,991

	Purchased kWh	Heating Degree Days	Cooling Degree Days	Spring Fall Flag	Number of Days in Month	CDM Activity	Number of Customers	Predicted Purchases
Jan-11	83,643,833	935.0	-	-	31.00	481,552	33,040	85,522,521
Feb-11	72,687,185	732.3	-	-	28.00	529,363	33,045	71,842,406
Mar-11	72,688,244	699.2	-	1.00	31.00	577,174	33,047	72,906,620
Apr-11	60,902,854	444.6	-	1.00	30.00	624,985	33,047	60,778,973
May-11	52,597,908	221.9	3.2	1.00	31.00	672,796	33,046	53,820,094
Jun-11	48,777,799	99.4	2.7	-	30.00	720,608	33,056	49,830,521
Jul-11	54,638,457	14.0	73.6	-	31.00	768,419	33,071	54,084,768
Aug-11	54,146,196	24.2	35.4	-	31.00	816,230	33,098	51,166,495
Sep-11	52,585,712	129.6	11.0	1.00	30.00	864,041	33,126	48,492,912
Oct-11	56,921,149	269.5	1.5	1.00	31.00	911,852	33,143	54,946,370
Nov-11	61,640,573	428.9	-	1.00	30.00	959,663	33,199	59,320,746
Dec-11	73,819,284	650.4	-	-	31.00	1,007,475	33,248	72,802,189
Jan-12	73,790,226	756.8	-	-	31.00	1,011,767	33,203	76,904,361
Feb-12	68,046,427	622.6	-	-	29.00	1,016,060	33,203	67,914,195
Mar-12	64,860,708	479.7	-	1.00	31.00	1,020,352	33,203	62,946,188
Apr-12	55,490,558	437.5	-	1.00	30.00	1,024,645	33,210	59,452,840
May-12	50,211,578	94.4	8.4	1.00	31.00	1,028,937	33,210	48,301,694
Jun-12	50,441,593	38.5	23.5	-	30.00	1,033,230	33,210	48,412,085
Jul-12	52,218,431	9.5	59.6	-	31.00	1,037,522	33,212	52,105,089
Aug-12	51,797,361	34.3	37.7	-	31.00	1,041,815	33,212	51,231,061
Sep-12	49,181,637	181.9	5.3	1.00	30.00	1,046,107	33,212	49,650,089
Oct-12	55,200,719	299.6	-	1.00	31.00	1,050,400	33,055	55,277,899
Nov-12	63,048,824	426.4	-	1.00	30.00	1,054,692	33,055	58,494,246
Dec-12	72,665,451	445.9	-	-	31.00	1,058,984	33,055	63,965,632
Jan-13	77,430,385	598.5	-	-	31.00	1,077,123	33,306	70,631,703
Feb-13	69,794,850	618.9	-	-	28.00	1,095,261	33,306	65,929,474
Mar-13	69,264,159	651.4	-	1.00	31.00	1,113,399	33,306	69,709,224
Apr-13	62,490,524	367.2	-	1.00	30.00	1,131,537	33,294	56,480,916
May-13	51,260,742	193.0	3.0	1.00	31.00	1,149,676	33,294	51,547,813
Jun-13	48,246,051	106.2	12.4	-	30.00	1,167,814	33,294	49,896,756
Jul-13	52,370,705	45.0	48.8	-	31.00	1,185,952	33,515	52,856,011
Aug-13	51,254,455	57.3	27.1	-	31.00	1,204,090	33,515	51,450,256
Sep-13	48,184,318	165.6	5.8	1.00	30.00	1,222,228	33,515	49,189,183
Oct-13	54,286,247	245.2	-	1.00	31.00	1,240,367	33,393	53,298,824
Nov-13	64,675,563	543.7	-	1.00	30.00	1,258,505	33,393	63,299,750
Dec-13	81,310,312	874.5	-	-	31.00	1,276,643	33,393	81,113,313
Jan-14	84,076,331	980.3	-	-	31.00	1,325,152	33,166	84,552,021
Feb-14	73,283,050	912.0	-	-	28.00	1,373,662	33,166	76,206,816
Mar-14	75,936,435	895.0	-	1.00	31.00	1,422,172	33,166	77,904,175
Apr-14	60,945,928	511.1	-	1.00	30.00	1,470,681	33,415	61,278,846
May-14	53,127,584	267.9	0.8	1.00	31.00	1,519,191	33,415	53,301,643
Jun-14	47,524,355	96.9	12.0	-	30.00	1,567,700	33,415	48,338,447
Jul-14	48,026,904	88.1	6.4	-	31.00	1,616,210	33,400	49,114,271
Aug-14	48,878,137	63.4	13.5	-	31.00	1,664,719	33,400	48,550,776
Sep-14	47,959,876	158.2	1.4	1.00	30.00	1,713,229	33,400	46,415,800
Oct-14	54,613,898	341.0	-	1.00	31.00	1,761,738	33,513	55,508,713
Nov-14	64,852,403	616.1	-	1.00	30.00	1,810,248	33,513	64,466,312
Dec-14	71,265,383	691.4	-	-	31.00	1,858,757	33,513	71,996,446

	Purchased kWh	Heating Degree Days	Cooling Degree Days	Spring Fall Flag	Number of Days in Month	CDM Activity	Number of Customers	Predicted Purchases
Jan-15	79,807,046	923.4	-	-	31.00	1,849,138	33,539	81,336,085
Feb-15	75,728,990	1,015.2	-	-	28.00	1,839,519	33,539	79,578,487
Mar-15	70,753,091	786.6	-	1.00	31.00	1,829,900	33,539	73,065,753
Apr-15	57,109,492	474.4	-	1.00	30.00	1,820,281	33,261	58,127,899
May-15	49,113,111	242.9	1.1	1.00	31.00	1,810,663	33,261	50,855,652
Jun-15	46,018,522	141.8	0.4	-	30.00	1,801,044	33,261	47,886,293
Jul-15	50,056,826	52.6	29.2	-	31.00	1,791,425	33,371	48,901,672
Aug-15	49,818,190	37.5	35.6	-	31.00	1,781,806	33,371	48,875,258
Sep-15	48,683,583	75.5	31.4	1.00	30.00	1,772,187	33,371	45,358,655
Oct-15	52,100,033	331.2	-	1.00	31.00	1,762,568	33,411	54,848,251
Nov-15	55,680,534	413.0	-	1.00	30.00	1,752,949	33,411	56,324,297
Dec-15	63,647,960	541.2	-	-	31.00	1,743,330	33,411	66,174,312
Jan-16	71,224,983	794.2	-	-	31.00	1,827,421	33,412	75,939,663
Feb-16	65,961,523	731.2	-	-	28.00	1,911,513	33,412	67,674,530
Mar-16	61,438,716	588.8	-	1.00	31.00	1,995,604	33,412	64,248,681
Apr-16	55,510,528	499.7	-	1.00	30.00	2,079,695	33,360	58,439,986
May-16	47,972,678	241.2	3.5	1.00	31.00	2,163,786	33,360	49,950,285
Jun-16	46,020,697	116.8	8.6	-	30.00	2,247,878	33,360	46,197,294
Jul-16	50,843,952	27.2	44.2	-	31.00	2,331,969	33,412	47,273,010
Aug-16	52,655,660	17.1	51.7	-	31.00	2,416,060	33,412	47,193,536
Sep-16	47,273,740	65.1	12.8	1.00	30.00	2,500,152	33,412	40,806,014
Oct-16	50,073,798	277.4	-	1.00	31.00	2,584,243	33,513	49,950,287
Nov-16	53,720,228	485.6	-	1.00	30.00	2,668,334	33,513	56,114,410
Dec-16	67,261,960	640.7	-	-	31.00	2,752,425	33,513	66,688,933
Jan-17		830.8	-	-	31.00	2,702,650	33,508	73,989,996
Feb-17		774.6	-	-	29.00	2,652,875	33,508	68,303,227
Mar-17		674.2	-	1.00	31.00	2,603,100	33,508	65,227,719
Apr-17		433.9	0.0	1.00	30.00	2,553,325	33,456	53,891,097
May-17		225.3	5.2	1.00	31.00	2,503,550	33,456	48,018,287
Jun-17		98.1	12.8	-	30.00	2,453,775	33,456	44,860,796
Jul-17		40.4	38.9	-	31.00	2,404,000	33,508	46,896,026
Aug-17		39.9	37.1	-	31.00	2,354,225	33,508	46,912,639
Sep-17		130.9	10.0	1.00	30.00	2,304,450	33,508	43,716,815
Oct-17		302.9	0.4	1.00	31.00	2,254,675	33,609	52,020,549
Nov-17		484.4	-	1.00	30.00	2,204,900	33,609	57,586,023
Dec-17		688.9	-	-	31.00	2,155,125	33,609	70,620,807
Jan-18		830.8	-	-	31.00	2,180,816	33,604	76,162,141
Feb-18		774.6	-	-	28.00	2,206,508	33,604	68,381,812
Mar-18		674.2	-	1.00	31.00	2,232,199	33,604	66,844,497
Apr-18		433.9	0.0	1.00	30.00	2,257,890	33,552	55,229,800
May-18		225.3	5.2	1.00	31.00	2,283,582	33,552	49,079,307
Jun-18		98.1	12.8	-	30.00	2,309,273	33,552	45,644,132
Jul-18		40.4	38.9	-	31.00	2,334,965	33,604	47,402,072
Aug-18		39.9	37.1	-	31.00	2,360,656	33,604	47,141,001
Sep-18		130.9	10.0	1.00	30.00	2,386,347	33,604	43,667,494
Oct-18		302.9	0.4	1.00	31.00	2,412,039	33,706	51,694,306
Nov-18		484.4	-	1.00	30.00	2,437,730	33,706	56,982,097
Dec-18		688.9	-	-	31.00	2,463,422	33,706	69,739,198

APPENDIX 2

CDM Load Forecast Adjustment Workform 2-I

Appendix 2-I
Load Forecast CDM Adjustment Work Form (2018)

Appendix 2-I was initially developed to help determine what would be the amount of CDM savings needed in each year to cumulatively achieve the four year 2011-2014 CDM target. This then

2018 is the fourth year of the six-year (2015-2020) Conservation First program. Final results for the 2011-14 program were issued in the fall of 2015, and the program is completed, although in some

The new six year (2015-2020) CDM program works in a slightly different manner to the previous 2011-2014 CDM program. Distributors will offer programs each year that, over the six years (from

2015-2020 CDM Program - 2018 fourth year of the current CDM plan

For the first year of the new 2015-2020 CDM plan, it is assumed that each year's program will achieve an equal amount of new CDM savings. This results in each year's program being about 1/6

			6 Year (2015-2020) kWh Target:				
			26,410,000				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**Total**
			%				
2015 CDM Programs						19.68%	19.68%
2016 CDM Programs						33.29%	33.29%
2017 CDM Programs						12.75%	12.75%
2018 CDM Programs						14.82%	14.82%
2019 CDM Programs						9.73%	9.73%
2020 CDM Programs						9.73%	9.73%
Total in Year						**100.00%**	**100.00%**
			kWh				
2015 CDM Programs	5,400,747.00	5,259,083.00	5,227,909.00	5,222,016.00	5,211,179.00	5,197,342.00	5,197,342.00
2016 CDM Programs		8,818,120.00	8,793,170.00	8,793,170.00	8,793,170.00	8,793,170.00	8,793,170.00
2017 CDM Programs			3,375,904.00	3,366,352.21	3,366,352.21	3,366,352.21	3,366,352.21
2018 CDM Programs				3,913,998.00	3,913,998.00	3,913,998.00	3,913,998.00
2019 CDM Programs					2,569,568.89	2,569,568.89	2,569,568.89
2020 CDM Programs						2,569,568.89	2,569,568.89
Total in Year	**5,400,747.00**	**14,077,203.00**	**17,396,983.00**	**21,295,536.21**	**23,854,268.11**	**26,410,000.00**	**26,410,000.00**

Note: The default formulae in the above table assume that the 2015-2020 kWh CDM target is achieved through persistence of CDM savings to the end of 2020. The distributor should enter

Determination of 2018 Load Forecast Adjustment

The Board determined that the "net" number should be used in its Decision and Order with respect to Centre Wellington Hydro Ltd.'s 2013 Cost of Service rates (EB-2012-0113). This approach has

From each of the 2006-2010 CDM Final Report, and the 2011 to 2016 CDM Final Reports, issued by the OPA/IESO for the distributor, the distributor should input the "gross" and "net" results of the

		Net-to-Gross Conversion		
Is CDM adjustment being done on a "net" or "gross" basis?				**net**
Persistence of Historical CDM programs to 2015	**"Gross" kWh**	**"Net" kWh**	**Difference kWh**	**"Net-to-Gross" Conversion Factor ('g')**
2006-2010 CDM programs				**0**
2011 CDM program				**0**
2012 CDM program				**0**
2013 CDM program				**0**
2014 CDM program				**0**
2015 CDM program				**0**
2016 CDM program				**0**
2006 to 2016 OPA CDM programs: Persistence to 2018.	-	-	-	0.00%

The default values below represent the factor used for how each year's CDM program is factored into the manual CDM adjustment. Distributors can choose alternative weights of "0", "0.5" or "1"

These factors do not mean that CDM programs are excluded, but the assumption that impacts of previous year CDM programs are already implicitly reflected in the actual data for historical years

Weight Factor for Inclusion in CDM Adjustment to 2018 Load Forecast

	2015	**2016**	**2017**	**2018**	**2019**	**2020**	
Weight Factor for each year's CDM program impact on 2018 load forecast	0		1	0.5	0	0	Distributor can select "0", "0.5", or "1" from drop-down list
Default Value selection rationale.	*Full year impact of 2015 CDM is assumed to be reflected in the base forecast, as the full year persistence of 2015 CDM programs is in the 2016 historical actual data. No further impact is necessary for the manual adjustment to the load forecast.*	*Default is 0.5, but one option is for full year impact of persistence of 2016 CDM programs on 2018 load forecast, but 50% impact in base forecast (first year impact of 2016 CDM programs on 2016 actuals, which is part of the data underlying the base load*	*Full year impact of persistence of 2017 programs on 2018 load forecast. 2017 CDM program impacts are not in the base forecast.*	*Only 50% of 2017 CDM programs are assumed to impact the 2018 load forecast based on the "half-year" rule.*	*2019 and 2020 are future years beyond the 2018 test year. No impacts of CDM programs beyond the 2018 test year are factored into the test year load forecast.*		

2015-2020 LRAMVA and 2018 CDM adjustment to Load Forecast

One manual adjustment for CDM impacts to the 2018 load forecast is made. There is a different but related threshold amount that is used for the 2018 LRAMVA amount for Account 1568.

The amount used for the CDM threshold of the LRAMVA is the kWh that will be used to determine the base amount for the LRAMVA balance for 2018, for assessing performance against the six-year target.

If used to determine the manual CDM adjustment for the system purchased kWh, the proposed loss factor should correspond with the proposed total loss factor calculated in Appendix 2-R .

The Manual Adjustment for the 2018 Load Forecast is the amount manually subtracted from the system-wide load forecast (either based on a purchased or billed basis) derived from the base forecast from historical data. If the distributor has developed their load forecast on a system purchased basis, then the manual adjustment should be on a system purchased basis, including the adjustment for losses. If the load forecast has been developed on a billed basis, either on a system basis or on a class-specific basis, the manual adjustment should be on a billed basis, excluding losses.

The distributor should determine the allocation of the savings to all customer classes in a reasonable manner (e.g. taking into account what programs and what IESO-measured impacts were directed at specific customer classes), for both the LRAMVA and for the load forecast adjustment.

	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**Total for 2018**
Amount used for CDM threshold for LRAMVA (2018)			3,366,352	3,913,998			**7,280,350**
Manual Adjustment for 2018 Load Forecast (billed basis)	-	-	3,366,352	1,956,999			5,323,351
Manual Adjustment for 2018 LDC-only CDM programs (billed basis)							
Total Manual Forecast to Load Forecast	-	-	3,366,352	1,956,999			**5,323,351**
Proposed Loss Factor (TLF)	1.0489%	Format: X.XX%					
Manual Adjustment for 2018 Load Forecast (system purchased basis)	-	-	3,401,662	1,977,526			**5,379,188**

Manual adjustment uses "gross" versus "net" (i.e. numbers multiplied by (1 + g). The Weight factor is also used to calculate the impact of each year's program on the CDM adjustment to the 2018

APPENDIX 3

Board Appendix 2-N Shared Services and Corporate Cost Allocation

Appendix 2-N
Shared Services and Corporate Cost Allocation [1]

Year: 2013 Approved

Shared Services

Name of Company From	 To	Service Offered	Pricing Methodology	Price for the Service $	Cost for the Service $
PUC Distribution	PUC Services	Building rental		$ -	$ -

Year: 2013 Actual

Shared Services

Name of Company From	 To	Service Offered	Pricing Methodology	Price for the Service $	Cost for the Service $
PUC Distribution	PUC Services	Building rental - 2013 - Account 4327	Cost - no markup	$2,281,174.80	$2,281,174.80

Year: 2014 Actual

Shared Services

Name of Company From	 To	Service Offered	Pricing Methodology	Price for the Service $	Cost for the Service $
PUC Distribution	PUC Services	Building rental - 2014 - Account 4327	Cost - no markup	$1,246,600.41	$1,246,600.41

Year: 2015 Actual

Shared Services

Name of Company From	 To	Service Offered	Pricing Methodology	Price for the Service $	Cost for the Service $
PUC Distribution	PUC Services	Building rental - 2015 - Account 4327	Cost - no markup	$1,240,120.24	$1,240,120.24

Year: 2016 Actual

Shared Services

Name of Company From	 To	Service Offered	Pricing Methodology	Price for the Service $	Cost for the Service $
PUC Distribution	PUC Services	Building rental - 2016 - Account 4327	Cost - no markup	$1,293,858.00	$1,293,858.00

Year: 2017 Bridge Year

Shared Services

Name of Company From	 To	Service Offered	Pricing Methodology	Price for the Service $	Cost for the Service $
PUC Distribution	PUC Services	Building rental - 2017 - Account 4327	Cost - no markup	$1,332,390.95	$1,332,390.95

Year: 2018 Test Year

Shared Services

Name of Company From	 To	Service Offered	Pricing Methodology	Price for the Service $	Cost for the Service $
PUC Distribution	PUC Services	Building rental - 2018 - Account 4327	Cost - no markup	$1,334,160.93	$1,334,160.93

PUC Distribution Inc.

EB-2017-0062

Filed: March 29, 2018

EXHIBIT 4:

OPERATING EXPENSES

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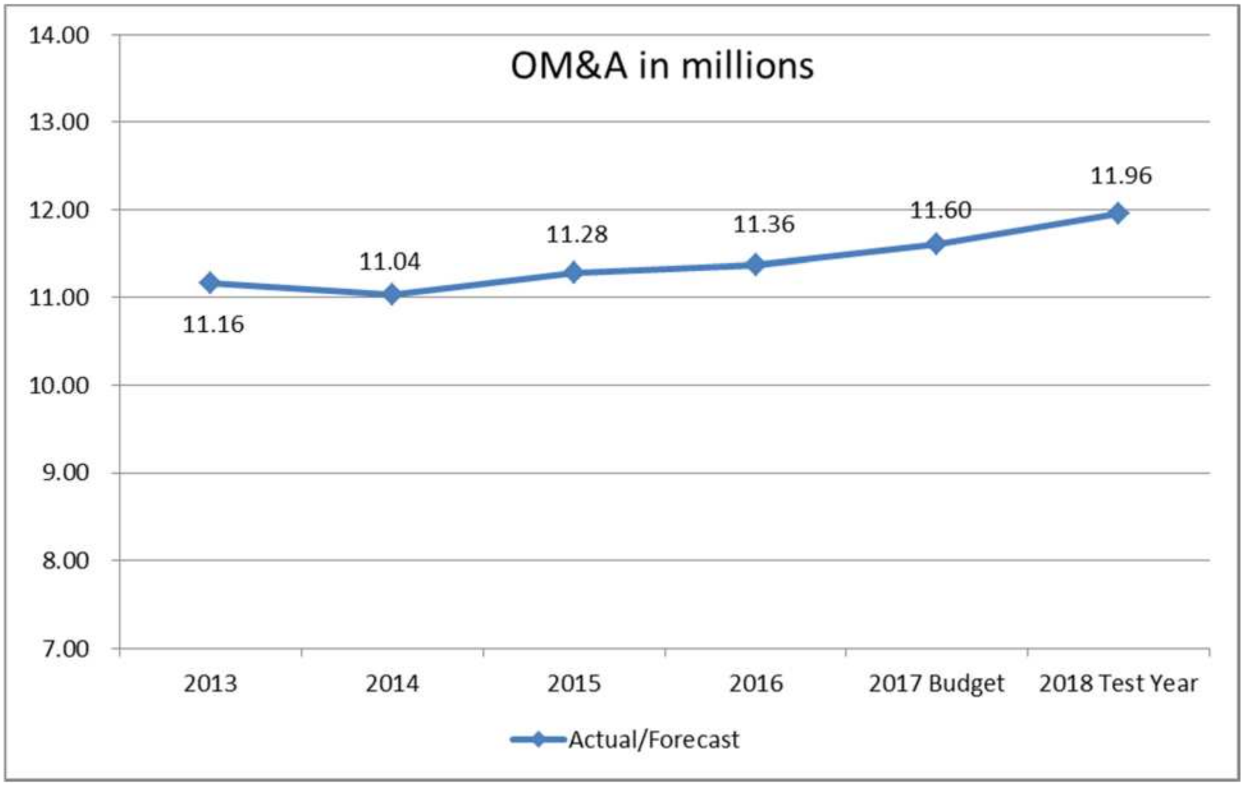
Exhibit 4: Operating Expenses

2.4.1 Overview

PUC Distribution determines its OM&A costs through an analysis of the costs it incurs to adapt to operate and maintain the distribution system while remaining responsive to regulatory changes. PUC Distribution Inc. ("PUC Distribution"), through its affiliate PUC Services Inc. ("PUC Services") operates using a shared services model. PUC Distribution has no employees but rather relies on PUC Services to provide the necessary resources at cost to operate the distribution utility. The model allows resources to be allocated to PUC Distribution as required especially during times when special or non-recurring projects are undertaken. In general expenses may fluctuate between categories as more attention is required for a specific category due to a specific need, emergency or a change to regulated/mandated services to be provided. Also in general, inflationary increases put upward pressure on costs.

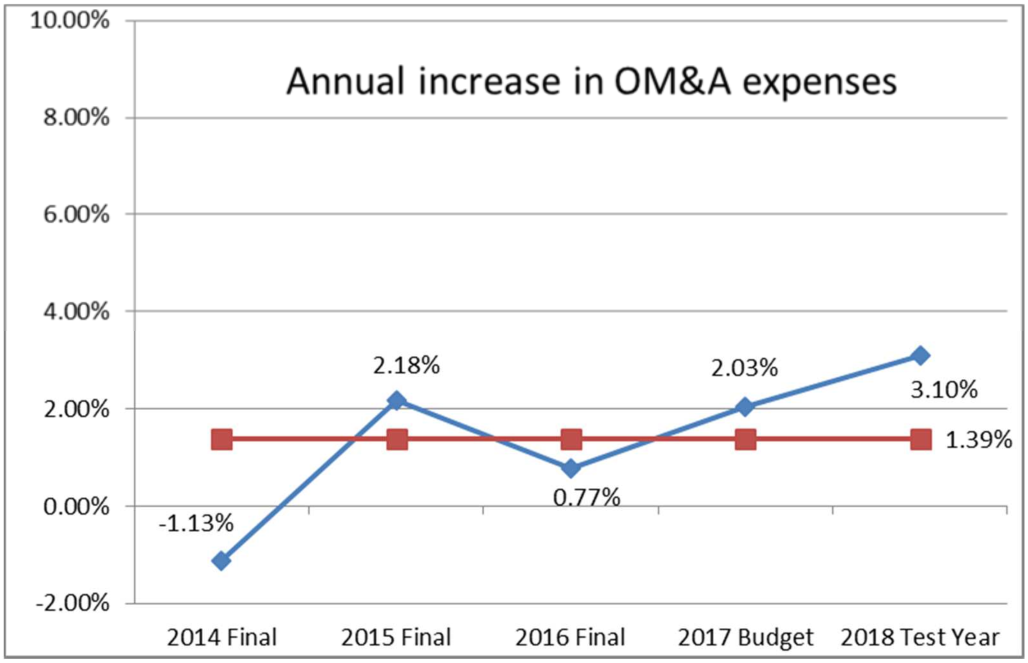
As shown in Figure 4-1 Actual/Forecast OM&A below, OM&A expenses have increased from $11.16 million in 2013 to $11.96 million in the 2018 test year request for approval. This equates to an average annual increase of 1.4%. Despite inflationary and regulatory pressures, the average annual increase of 1.4% over the 2013 to 2018 period has been below the rate of inflation.

Figure 4-1 – Actual/Forecast OM&A



The year over year percentage increases are indicated in Figure 4-2 Annual OM&A Percentage Increase.

Figure 4-2 – Annual OM&A Percentage Increase



PUC Distribution is requesting the following items in its Cost of Service rate application in 2018 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,
- An additional staff resource to address the 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 3.10%, which as noted above results in an average annual increase of 1.4% over 2013 actuals.

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.

2.4.2 Summary and Cost Driver Tables

Operating, Maintenance and Administrative ("OM&A") Test Year Levels

OM&A Budgeting Process Used by PUC Distribution

The operating budget is prepared annually by management and is reviewed and approved by the Board of Directors. The budget is prepared prior to the start of each fiscal year, and provides a plan against which actual results may be evaluated. Once approved the budget is only revised if a material change in the plan is required. Capital and operating budgets are formulated to achieve PUC Distribution's business objectives in a prudent and sustainable manner while considering customer rate impacts.

The following directives are used to prepare the annual budgets:

- Outside expenses for all department budgets are built using previous year actual, current year forecast and current year budgets as the base; for example, when compiling the 2017 budget, the previous year actual (2015), the current year forecast (2016) and the current year budget (2016) would be used;
- Significant variances in spending from prior years must be explained and documented;
- Review the headcount of the department for accuracy and outline any changes;
- Prepare a total labour budget by department using projected wage and benefit cost. Overtime and account distribution are based on previous years actual plus any identified changes for the future year.

- The Finance department then completes an initial consolidation of all departments to develop a draft budget. Finance works with each department to identity variances and issues for consideration.

- Senior management reviews the draft budget and makes changes to balance cost control with achieving core objectives. In an effort to contain costs and explore efficiencies and still provide an acceptable level or reliability and customer service, the team looks in detail for discretionary costs and identifies cost areas that can be delayed or addressed with alternative approaches.

- Senior management makes a submission to the Board of Directors on the proposed budget and formal approval is requested.

PUC Distribution's Test Year Operating, Maintenance and Administrative ("OM&A") expenses are $11,955,834 including expenses relating to the Low Income Energy Assistance Program ("LEAP") and payments in lieu of property taxes. A summary of OM&A expenses from the 2013 Board Approved to the 2018 Test Year is found in Table 4-1 below.

Table 4-1 - Summary of OM&A Expenses

	2013 Board Approved Less LEAP	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge	2018 Test
Operations	$ 3,301,081	$ 3,667,835	$ 3,558,777	$ 3,702,949	$ 3,771,352	$ 3,752,937	$ 4,026,057
Maintenance	$ 2,228,075	$ 2,324,284	$ 2,214,631	$ 2,274,649	$ 2,206,518	$ 2,103,645	$ 2,186,573
Billing & Collecting	$ 1,198,786	$ 1,274,108	$ 1,373,301	$ 1,417,758	$ 1,572,173	$ 1,618,876	$ 1,575,376
Community Relations	$ 579,787	$ 501,391	$ 557,701	$ 670,544	$ 626,657	$ 741,795	$ 618,800
Admin & General	$ 2,645,218	$ 4,372,332	$ 3,269,578	$ 3,152,837	$ 3,132,861	$ 3,314,987	$ 3,480,028
Taxes other than Income Taxes		$ 46,062	$ 40,740	$ 36,160	$ 31,755	$ 40,000	$ 45,000
LEAP		$ 19,873	$ 22,610	$ 22,926	$ 23,619	$ 24,000	$ 24,000
Total	**$ 9,952,947**	**$ 12,205,885**	**$ 11,037,338**	**$ 11,277,823**	**$ 11,364,935**	**$ 11,596,240**	**$ 11,955,834**
% Change (year over year)		22.64%	-9.57%	2.18%	0.77%	2.04%	3.10%
Building Expenses*		$ 1,042,725					
Normalized Total	**$ 9,952,947**	**$ 11,163,160**	**$ 11,037,338**	**$ 11,277,823**	**$ 11,364,935**	**$ 11,596,240**	**$ 11,955,834**
% Change (year over year)		12.16%	-1.13%	2.18%	0.77%	2.04%	3.10%

* The expense of $1,042,725 relates to the treatment of the new building usage fee included in Admin and General Expenses. As shown in Figure 4-3 below, 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. As a result, to ensure an apples-to-apples comparison of 2013 BA and 2013 Actuals, an adjustment is proposed to remove the $1.042M building expense. The treatment results in a variance in both revenue and expense with no net difference overall. The treatment was changed in the 2014 actual and onward to reflect the treatment in the cost of service rate application.

Figure 4-3 Building Usage Fee

PUC Distribution

	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**

Table 4-2 - OM&A Annual Change - 2013 BA to 2018 Test Year

	2013 BA	2013	2014	2015	2016	2017	2018
Total	**$ 9,952,947**	**$ 12,205,885**	**$ 11,037,338**	**$ 11,277,823**	**$ 11,364,935**	**$ 11,596,240**	**$ 11,955,834**
Building Expenses*		$ 1,042,725					
Normalized Total	**$ 9,952,947**	**$ 11,163,160**	**$ 11,037,338**	**$ 11,277,823**	**$ 11,364,935**	**$ 11,596,240**	**$ 11,955,834**

OM&A expenses reflect costs required to operate, maintain and sustain the electricity distribution operations, including new expenditures to address regulatory changes. PUC Distribution’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%. The majority of the increase occurred between 2012 and 2013.

Due to increased workload, regulatory requirements and costs necessary to service customers, PUC Distribution’s expenditures were $11.16 million in 2013 compared to the approved amount in rates of $9.95 million. The difference of $1.21 million is being absorbed by the shareholder. The increase of $1.21 million from 2012 to 2013 is in the following areas described in Table 4-3 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, as noted above the 2013 expenses have been reduced by the increased amount ($1,042,275) included in miscellaneous revenue which offsets the new shared corporate headquarter cost.

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. Indeed, since 2012, PUC Distribution has consistently earned below the deemed ROE, see Table 1-24: Scorecard Performance Category – Financial Ratios in section 2.1.7 Performance Management of Exhibit 1. Where there is a mismatch between costs and rates, there is a negative impact on the utility’s return on equity. Over time the costs for PUC Distribution have increased while the rates have remained the same, allowing ratepayers to benefit from artificially low rates for years. However, now it is time to properly align rates and costs in order to maintain the financial viability of PUC Distribution.

Table 4-3 PUC Distribution 2013 Expenditures

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 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	

OM&A expenses have increased from $11.16 million in 2013 to $11.96 million in the 2018 test year request. This equates to an average annual increase of 1.4%. Despite inflationary and regulatory pressures, the average annual increase over the 2013 to 2018 period has been below the rate of inflation.

Aside from the increase from 2012 to 2013, the other significant increase is between 2017 and the 2018 test year. 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 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 3.10%, which as noted above is an average annual increase of 1.4% over 2013 levels.

Associated Cost Drivers and Significant Changes

Table 4-4 - Summary of Cost Drivers - 2013 Actuals to 2018 Test Year

Description	Amount
2013 Actuals	$ 12,205,886
Building Usage Fee	-$ 1,042,275
2013 Actual Total	**$ 11,163,611**
Description of Cost Drivers	
Salaries, Wages & Benefits	$ 644,026
Building	-$ 173,796
Cost Drivers less than materiality	$ 321,992
OM&A Increase from 2013 Actuals	$ 792,222
OM&A % Increase	7.10%
2018 Test Year Expenses	**$ 11,955,833**

As shown in Table 4-4, Salaries, wages and benefits: is the most significant driver of PUC Distribution's OM&A costs, showing approximately a $644,000 increase from the 2013 Actual Year. PUC Distribution's complement has decreased by 3.45 FTEs since the 2013 Actual Year; however, total salaries and wages have increased by $474,764 and benefits have increased by $218,826 as outlined in Table 4-5 below. Total salaries, wages and benefits have increased less than the total wage rate increases due to the reduction of FTEs during this period.

Table 4-5 - Overall Compensation Trend Summary: 2013 Actual to 2018 Test Year

Description	2013 Actuals	2018 Test Year	Variance
FTE's	87.61	84.16	-3.45
			-3.94%
Salaries/Wages	$7,220,328	$7,695,092	$474,764
			6.58%
Benefits	$1,789,338	$2,008,164	$218,826
			12.23%
Total Compensation (Salary, Wages & Benefits	$9,009,666	$9,703,256	$693,590
			7.70%

Table 4-6 - Summary of Cost Drivers - 2017 Bridge Year to 2018 Test Year

Description	Amount
2017 Bridge Year	$ 11,596,241
Description of Cost Drivers	
Salaries, Wages & Benefits	$ 339,235
Cost Drivers less than materiality	$ 20,358
OM&A Increase from 2017 Bridge Year	$ 359,592
OM&A % Increase	3.10%
2018 Test Year Expenses	**$ 11,955,833**

Salaries, wages and benefits: is the most significant driver of PUC Distribution's OM&A costs, showing approximately a $339,235 increase from the 2017 Bridge Year. PUC Distribution's complement has decreased by 1.54 FTEs since the 2017 Bridge Year; however, total salaries and wages have increased by $109,033 and benefits have decreased by $20,449 as outlined in Table 4-7 below. Total salaries, wages and benefits have increased less than the total wage rate increases due to the reduction of FTEs during this period.

Table 4-7 - Overall Compensation Trend Summary: 2017 Bridge Year to 2018 Test Year

Description	2017 Bridge Year	2018 Test Year	Variance
FTE's	85.70	84.16	-1.54
			-1.80%
Salaries/Wages	$ 7,586,059	$ 7,695,092	$ 109,033
			1.44%
Benefits	$ 2,028,613	$ 2,008,164	-$ 20,449
			-1.01%
Total Compensation (Salary, Wages & Benefits	$ 9,614,672	$ 9,703,256	$ 88,584
			0.92%

Overall Trends in Costs

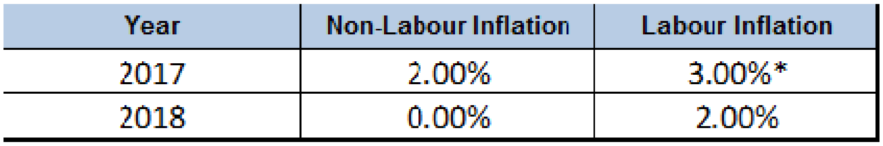
The overall trends in cost for OM&A per customer from 2013 to 2018 is 7.70%. The overall trend in cost for OM&A per customer from 2017-2018 is an increase of 0.92%. These increases factor in improvements in productivity, cost containment measures and account for inflation. In general terms, the changes in year-over-year employee compensation in OM&A is a result of several drivers including succession planning, attrition, vacancies, and sick leaves. Base salaries reflect the cost of living and salary progression increases arising from recent collective bargaining agreements with unionized employees as well as commensurate percentage increases for management staff.

The reduction in FTEs from 2013 to 2018 is largely a result of the allocation of staff members' time to affiliate services including PUC Services as well as attrition. There is less of a reduction of FTEs from 2017-2018 as on the balance there was less overlap of positions and less allocation of FTE time to affiliate services.

The relative increase in total compensation from 2013-2018 when compared to the reduction of FTEs is largely a result of annual increases in compensation for which PUC Distribution was responsible, despite FTE time being allocated away from PUC Distribution. The variance between the total compensation and FTEs is reduced in 2017-2018 because on the balance there was an increase in FTEs due to overlap of positions for training and succession purposes.

Inflation Rate Assumed

Table 4-8 – Non-Labour and Labour Inflation Factors



Year	Non-Labour Inflation	Labour Inflation
2017	2.00%	3.00%*
2018	0.00%	2.00%

As shown in Table 4-8, The inflation rate assumed for labour is 2% and 0% for non-labour. As noted about, while the IPI effective for a rate application in 2018 is 1.2%, PUC Distribution has reduced the non-labour inflation rate to 0% for budgeting purposes. PUC Distribution believes that the inflation increases will be offset by the expected operating efficiencies to be achieved in 2018.

Business Environment Changes

Since PUC Distribution's last rebasing in 2013, there has been a number of significant business environment changes that will impact operating costs – the introduction of Metering Inside the Settlement Timeframe (MIST); the introduction of Ontario One Call; Measurement Canada sampling requirements now that PUC Distribution's smart meters are approaching seal expiry; new Independent Electricity System Operator (IESO) requirements for under-frequency load shedding scheme; overhead transformer PCB testing; Renewed Regulatory Framework for Electric Distributors; and Ontario Clean Energy Benefit (OCEB) and Ontario Electricity Support Program (OESP) government programs for customers.

Mist Meters

PUC Distribution is required to change out approximately 360 existing non interval meters for customers that are >50 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. Communication costs are estimated to be an additional $45,000 per year.

Ontario One Call

The Ontario Underground Infrastructure Notification System Act, 2012, has made it mandatory for all infrastructure owners to be part of the Ontario One Call system. Over the historical period, locate request volumes have increased greatly due in part to the exposure brought about by this legislation and the ease with which locates can now be requested. Costs are estimated to be $18,000 one-time costs and $7,000 on-going annual costs. As a result of this, PUC Distribution has had to revise the processes it previously had in place to manage this increased workload. This included:

- Purchasing software to streamline the receipt and processing of requests;
- Purchasing hardware to allow requests to be processed electronically in the field, increasing efficiency;
- Increases in overtime to ensure legislated deadlines are met; and
- Integrating other business systems with the request processing environment (i.e. developing and accessing the data in the GIS (Geographic Information System) spatial database.

Smart Meter Sampling For Reverification

As part of a legislated requirement, PUC Distribution replaced approximately 30,000 electro-mechanical type revenue meters with electronic smart meters in 2009. The new electronic smart meters selected by PUC Distribution for use were manufactured by Sensus and had 10 year seal life and will expire in 2019. As per Measurement Canada requirements a meter with an expired seal cannot be left in service for revenue / billing purposes.

Measurement Canada's (MC) Statistical Method Specification (S-S-06) replaced the previous 1986 mechanical meter reverification standard LMB-EG-04; and defines how an electronic smart meter owner can utilize meter sampling for the purposes of extending the reverification period of an in-service lot of meters. Differing from the LMB-EG-04 Standard where the meter testing agency would be responsible for meter sampling data; the S-S-06 specification now places this and additional clerical data management and meter tracking responsibilities on the utility.

The internal labour necessary to accomplish the reverification process has yet to be determined.

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 vacancies estimated at $100,000 each for Salaries, Wages and Benefits.

Overhead Transformer PCB Testing

Environment and Climate Change Canada has issued the 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. It is estimated that Overhead Transformer PCB Testing will cost $80,000.

Renewed Regulatory Framework for Electric Distributors

In October 2012, the OEB released its Report, *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (RRFE). Over the last several years PUC Distribution has implemented several initiatives to address the customer focus area of the RRFE - services are provided in a manner that responds to identified needs and preferences of customers. Since it last rebasing in 2013, PUC Distribution has implemented the following to be more proactive with customers: added staff to focus on customer communications, upgraded the telephone system and added an interactive voice response system, made available social media interaction, issued customer satisfaction and safety surveys, continued the elementary school safety education program, issued a strategic direction plan survey, held public information sessions with the Sault Ste. Marie Public Library and the Sault Ste. Marie Innovation Centre, held neighbourhood information sessions, implemented customer connect (enhanced metering and billing information on line), upgraded the customer information system (CIS), implemented Mcare (field service order software) and an automated vehicle location (AVL) system to more efficiently respond to customer field requests. The estimated cost of these programs is $175,000.

Cessation/Implementation of the OCEB and the OESP respectively

Government and regulatory policy changes affect PUC Distribution in a variety of ways. The significant impacts of these changes are in the billing and customer service departments. Each policy change which modifies a customer bill is tested through both bill generation and bill printing. The impact on the customer service department is an increase in customer inquiries, which increases phone and email traffic. PUC Distribution is making efforts to reduce call volumes (online customer portal), but each policy change results in an influx of customer inquiries. This is particularly apparent when changes are made to low income programs.

The OCEB program ceased December 31, 2015 and was replaced with the OESP program. These programs changes required a programming change to PUC Distribution’s customer information and billing system. The required programming change was a custom change, for which, PUC Distribution incurred costs to implement/ remove OESP OCEB charges. The introduction of the OESP program in 2015 required integration of PUC Distribution’s CIS system with the provincial OESP validation system. This required information technology staff time as well as an additional custom programming cost for the CIS system. The change also came with impacts to the billing department as the OESP credit required changes to the bill generation and printing functions. The charges related to the cessation and implementation of the OCEB and OESP mostly consisted of staff salaries and wages which were not tracked separately.

2.4.2 Summary and Cost Driver Tables

PUC Distribution follows the Board's Accounting Procedures Handbook ("APH") in distinguishing work performed between operations and maintenance. A summary of PUC Distribution's OM&A expenses (5005-5695, 6110, 6205), including payments in lieu of property taxes and LEAP, for the 2013 Board Approved, 2013 Actual, 2014 Actual, 2015 Actual, 2016 Actual, 2017 Bridge and 2018 Test Year is provided in Table 4-9 - Summary of Recoverable OM&A Expenses below, which is consistent with the Board's Appendix 2-JA. A copy of the Board's Appendix 2-JA is also included in Appendix 1 to this Exhibit. PUC Distribution is proposing to receive the 2018 Test Year costs through distribution rates for the 2018 Test Year.

Table 4-9 - Summary of Recoverable OM&A Expenses

Appendix 2-JA
Summary of Recoverable OM&A Expenses

	Last Rebasing Year (2013 Board-Approved)	Last Rebasing Year (2013 Actuals)	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Operations	$ 3,560,312	$ 3,667,835	$ 3,558,777	$ 3,702,949	$ 3,771,352	$ 3,752,937	$ 4,026,057
Maintenance	$ 1,978,405	$ 2,324,284	$ 2,214,631	$ 2,274,649	$ 2,206,518	$ 2,103,645	$ 2,186,573
SubTotal	**$ 5,538,717**	**$ 5,992,119**	**$ 5,773,408**	**$ 5,977,598**	**$ 5,977,870**	**$ 5,856,582**	**$ 6,212,629**
%Change (year over year)	▨	▨	-3.6%	3.5%	0.0%	-2.0%	6.1%
%Change (Test Year vs Last Rebasing Year - Actual)							3.7%
Billing and Collecting	$ 1,163,141	$ 1,274,108	$ 1,373,301	$ 1,417,758	$ 1,572,173	$ 1,618,876	$ 1,575,376
Community Relations	$ 544,548	$ 501,391	$ 557,701	$ 670,544	$ 626,657	$ 741,795	$ 618,800
Administrative and General	$ 2,706,539	$ 4,438,267	$ 3,332,931	$ 3,211,923	$ 3,188,235	$ 3,378,987	$ 3,549,028
SubTotal	**$ 4,414,229**	**$ 6,213,766**	**$ 5,263,933**	**$ 5,300,225**	**$ 5,387,065**	**$ 5,739,658**	**$ 5,743,204**
%Change (year over year)	▨	▨	-15.3%	0.7%	1.6%	6.5%	0.1%
%Change (Test Year vs Last Rebasing Year - Actual)							-7.6%
Total	**$ 9,952,946**	**$ 12,205,885**	**$ 11,037,341**	**$ 11,277,823**	**$ 11,364,935**	**$ 11,596,240**	**$ 11,955,833**
%Change (year over year)	▨	▨	-9.6%	2.2%	0.8%	2.0%	3.1%

	Last Rebasing Year (2013 Board-Approved)	Last Rebasing Year (2013 Actuals)	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year
Operations	$ 3,560,312	$ 3,667,835	$ 3,558,777	$ 3,702,949	$ 3,771,352	$ 3,752,937	$ 4,026,057
Maintenance	$ 1,978,405	$ 2,324,284	$ 2,214,631	$ 2,274,649	$ 2,206,518	$ 2,103,645	$ 2,186,573
Billing and Collecting	$ 1,163,141	$ 1,274,108	$ 1,373,301	$ 1,417,758	$ 1,572,173	$ 1,618,876	$ 1,575,376
Community Relations	$ 544,548	$ 501,391	$ 557,701	$ 670,544	$ 626,657	$ 741,795	$ 618,800
Administrative and General	$ 2,706,539	$ 4,438,267	$ 3,332,931	$ 3,211,923	$ 3,188,235	$ 3,378,987	$ 3,549,028
Total	**$ 9,952,946**	**$ 12,205,885**	**$ 11,037,341**	**$ 11,277,823**	**$ 11,364,935**	**$ 11,596,240**	**$ 11,955,833**
%Change (year over year)	▨	▨	-9.6%	2.2%	0.8%	2.0%	3.1%

Table 4-10 - Summary of Recoverable OM&A Expenses Continued

	Last Rebasing Year (2013 Board-Approved)	Last Rebasing Year (2013 Actuals)	Variance 2013 Board-approved – 2013 Actuals	2014 Actuals	Variance 2014 vs. 2013 Actuals	2015 Actuals	Variance 2015 vs. 2014 Actuals	2016 Actuals	Variance 2016 Actuals vs. 2015 Actuals	2017 Bridge Year	Variance 2017 Bridge vs. 2016 Actuals	2018 Test Year	Variance 2018 Test vs. 2017 Bridge
Operations	$ 3,560,312	$ 3,667,835	$ 107,523	$ 3,558,777	-$ 109,058	$ 3,702,949	$ 144,172	$ 3,771,352	$ 68,403	$ 3,752,937	-$ 18,415	$ 4,026,057	$ 273,120
Maintenance	$ 1,978,405	$ 2,324,284	$ 345,879	$ 2,214,631	-$ 109,653	$ 2,274,649	$ 60,018	$ 2,206,518	-$ 68,131	$ 2,103,645	-$ 102,873	$ 2,186,573	$ 82,927
Billing and Collecting	$ 1,163,141	$ 1,274,108	$ 110,967	$ 1,373,301	$ 99,193	$ 1,417,758	$ 44,457	$ 1,572,173	$ 154,415	$ 1,618,876	$ 46,703	$ 1,575,376	-$ 43,500
Community Relations	$ 544,548	$ 501,391	-$ 43,157	$ 557,701	$ 56,310	$ 670,544	$ 112,843	$ 626,657	-$ 43,887	$ 741,795	$ 115,138	$ 618,800	-$ 122,995
Administrative and General	$ 2,706,539	$ 4,438,267	$ 1,731,728	$ 3,332,931	-$ 1,105,336	$ 3,211,923	-$ 121,008	$ 3,188,235	-$ 23,688	$ 3,378,987	$ 190,752	$ 3,549,028	$ 170,041
Total OM&A Expenses	$ 9,952,946	$ 12,205,885	$ 2,252,939	$ 11,037,341	-$ 1,168,544	$ 11,277,823	$ 240,482	$ 11,364,935	$ 87,112	$ 11,596,240	$ 231,305	$ 11,955,833	$ 359,593
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)													
Total Recoverable OM&A Expenses	$ 9,952,946	$ 12,205,885	$ 2,252,939	$ 11,037,341	-$ 1,168,544	$ 11,277,823	$ 240,482	$ 11,364,935	$ 87,112	$ 11,596,240	$ 231,305	$ 11,955,833	$ 359,593
Variance from previous year	▨	▨	▨	-$ 1,168,544	▨	$ 240,482	▨	$ 87,112	▨	$ 231,305	▨	$ 359,593	▨
Percent change (year over year)	▨	▨	▨	-10%	▨	2%	▨	1%	▨	2%	▨	3%	▨
Percent Change: Test year vs. Most Current Actual	▨	▨	▨	▨	▨	▨	▨	5.20%	▨	▨	▨	▨	▨
Simple average of % variance for all years	▨	▨	▨	▨	▨	▨	▨	-2.05%	▨	▨	▨	▨	2%
Compound Annual Growth Rate for all years	▨	▨	▨	▨	▨	▨	▨		▨	▨	▨	▨	-0.4%
Compound Growth Rate (2016 Actuals vs. 2013 Actuals)	▨	▨	▨	▨	▨	▨	▨	-2.35%	▨	▨	▨	▨	▨

Cost Drivers

Consistent with the Board's Appendix 2-JB, Table 4-11 provides a list of the cost drivers that affected year over year OM&A spending or, where the cost driver is common or recurring, expenditures that have impacted multiple years. A copy of the Board's Appendix 2-JB can also be found in Appendix 2 to this Exhibit.

Table 4-11 - Recoverable OM&A Cost Driver Table

Appendix 2-JB
Recoverable OM&A Cost Driver Table[1,3]

OM&A	Last Rebasing Year (2013 Actuals)	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year
Reporting Basis	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Opening Balance[2]	$ 9,952,946	$ 12,205,886	$ 11,037,340	$ 11,277,823	$ 11,364,937	$ 11,596,241
Salaries, Wages & Benefits	$416,110	($62,523)	$373,054	$50,665	($56,405)	$339,235
Administrative	($55,701)	($23,580)	$46,586	$24,712	($29,985)	($5,205)
Training	($18,740)	($720)	($1,855)	($50,130)	$67,417	$6,395
Material	$34,342	$7,415	($84,896)	$93,964	($84,619)	$0
Trucking/Equipment	$24,429	($32,089)	$400	$28,557	$25,389	($0)
Bad Debt Expense	$74,345	($63,203)	$53,146	$207,209	($41,704)	($87,473)
Community Relations	($54,077)	($10,576)	$34,152	($41,472)	$104,316	($11,547)
Building	$1,486,260	($1,151,580)	($126,779)	($21,395)	$41,352	$42,331
Insurance	$47,521	$42,338	$4,114	($5,801)	($62,932)	($0)
Property Taxes	$3,241	$5,296	$4,906	$4,858	$4,651	$1,022
Outside Services	$232,027	$90,396	($40,144)	($126,376)	$99,127	$9,834
Postage	($14,738)	$14,889	($2,687)	($27,132)	$44,320	$0
Professional Fees	$77,491	($20,838)	$19,009	($55,553)	$71,996	$60,000
Memberships, Licenses, Fees	$7,341	$9,049	($2,829)	$466	($6,361)	$0
Computers	($28,417)	$34,477	($38,616)	$39,283	$20,348	$0
Telephone/Fibre	$25,645	($1,975)	$7,503	($30,335)	$26,149	$0
Income Tax	($4,141)	($5,322)	($4,581)	($4,404)	$8,245	$5,000
Closing Balance[2]	$ 12,205,886	$ 11,037,340	$ 11,277,823	$ 11,364,937	$ 11,596,241	$ 11,955,833

The following explanations detail the primary cost drivers that have influenced the increase in PUC Distribution's OM&A Expenditures since the last Cost of Service Application, up to and including the 2018 Test Year. Each driver is summarized by its net change year over year. PUC Distribution has provided comments on those variances great than its materiality level of $110,400.

Change in Salaries, Wages and Benefits

Last Rebasing to 2013 Actual - $416,110

Salaries, wages and benefits have increased by $416,110 between the 2013 Board Approved and 2013 Actual OM&A expenditures. This increase is a result of:

- Line Department – (Operations and Maintenance) - $237,884
    - Shift from capital to OM&A (e.g. Telecom deficiencies)
    - Lineman returned from sick leave therefore increasing FTE's from 2012
    - Additional 230 hours of call outs due to adverse weather
- Engineering Department – (Operations and Maintenance) - $96,684
    - Payroll transition of hours from capital to OM&A
- Other aggregated immaterial fluctuations - $81,542

2014 Actual to 2015 Actual - $373,054

Salaries, wages and benefits have increased by $373,054 between the 2014 and 2015 Actual OM&A expenditures. This increase is a result of:

- Line Department – (Operations and Maintenance) – $112,724
    - Reduction of Bell Fibre To The Home (FTTH) work shifting salaries, wages and benefits from capital to OM&A
- Engineering Department – (Operations and Maintenance) - $80,349

    - Reduction of Bell FTTH work shifting salaries, wages and benefits from capital to OM&A

- Communication Department – (Administration) - $48,428
    - Addition of a Communication Supervisor tasked with supporting the customer engagement initiative
- Metering Department – (Operations and Maintenance) - $70,920
    - Payroll transition of hours from capital to OM&A
- Other aggregated immaterial fluctuations - $60,633

2017 Bridge to 2018 Test Year - $339,235

Salaries, wages and benefits have increased by $339,235 between the 2017 Bridge and 2018 Test OM&A expenditures. This increase is a result of:

- Line Department – (Operations and Maintenance) - $149,390
    - Payroll transition of hours from capital to OM&A
- Finance Department – (Administration) – $70,197
    - Addition of a regulatory staff member
- Stations Department – (Operations and Maintenance) – $141,619
    - Additional station electrician including job progression
- Other aggregated immaterial fluctuations – ($21,971)

Bad Debt Expense – (Administration)

2015 Actual to 2016 Actual - $207,209

PUC Distribution fell behind processing bad debts in 2014 and 2015, but made a concentrated effort in 2016 to bring write-offs up to date. Other factors that contributed to the higher level of bad expense are the economic uncertainty in Sault Ste. Marie and the increased cost of energy.

Building – (Administration)

Last Rebasing to 2013 Actual - $1,486,260

PUC Distribution's new integrated office and service centre building was fully occupied in 2013. The entire building was rented to PUC Services, who in turn rented a portion of the building to the Public Utilities Commission of the City of Sault Ste. Marie ("Public Utilities Commission") and a portion back to PUC Distribution. The rent from PUC Services for the entire building is included in miscellaneous revenue and the rent for only the portion of the building used by PUC Distribution is included in expenses. In addition to the rent, which is a new expense, PUC Distribution's share of property taxes, janitorial services and utilities also increased as a result of the new building.

Increases over 2012: Rent $1,032,000, Janitor $30,200, Utilities $89,100, Property taxes $243,900

2013 Actual to 2014 Actual – ($1,151,580)

Building expenses in 2014 were lower than the 2013 amount due to the change in treatment of the new building fees. Commencing in 2014 only the portion of the building used by PUC Services and the Public Utilities Commission was included in revenue and there is no charge back to PUC Distribution in expenses. This resulted in the reduced expense.

2014 Actual to 2015 Actual – ($126,779)

Building expenses in 2015 were $126,779 below 2014 expenses. A greater portion of the building expenses were allocated through Stores in 2015. In addition, janitorial and utilities expenses were under prior year.

Outside Services

Last Rebasing to 2013 Actual - $232,027

Line clearing costs in 2013 were $162,800 (Operations and Maintenance) higher than the 2013 Board approved and 2012 actual. The 2012 actual costs were at a low level due to the area cleared in 2012. PUC Distribution has redefined its line clearing areas to better balance the annual area to be cleared.

The net increase between the reduction in contracted meter reading costs and the increased cost to operate the smart meter system was $78,200 (Administration) in 2013.

Other aggregated immaterial fluctuations total ($8,973).

2015 Actual to 2016 Actual – ($126,376)

Increased expenses in 2016 were OEB fees ($38,600) (Administration), the required public safety survey ($9,500) (Administration) and line clearing ($61,300) (Operations and Maintenance). Line clearing costs are dependent on the area to be cleared and tendering results. These increases were more than offset by reduced expenses in 2016 in the following areas:

- 2015 included work to address an Engineering records backlog ($15,500) (Administration),

- Staff training expenses were less in 2016 than 2015 ($12,200) (Administration)

- Substation Maintenance ($18,100) - reduced vegetation control in 2016 vs. 2015 and additional substation inspections in 2015 vs. 2016 (Operations and Maintenance)
- Transformation station ($43,400) – 115 kv switch repair in 2015 (Operations and Maintenance)
- Transformer remedial work in 2016 was under the 2015 level ($141,800) (Operations and Maintenance)
- Other aggregated immaterial fluctuations total ($4,776).

Recoverable OM&A Cost Per Customer and Per Full Time Equivalent

Table 4-12 below is a summary of the OM&A cost per customer and per full-time equivalent (“FTE”). This table is consistent with the Board’s Appendix 2-L, which is included as Appendix 5 to this Exhibit. The number of customers is based on an annual average for each metered rate class.

Table 4-12 - Recoverable OM&A Cost per Customer and per Full Time Equivalent (FTE)

Appendix 2-L
Recoverable OM&A Cost per Customer and per FTE [1]

	Last Rebasing Year - 2013- Board Approved	Last Rebasing Year - 2013- Actual	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
OM&A Costs							
O&M	$ 5,538,717	$ 5,992,119	$ 5,773,408	$ 5,977,598	$ 5,977,870	$ 5,856,582	$ 6,212,629
Admin Expenses	$ 4,414,229	$ 6,213,766	$ 5,263,933	$ 5,300,225	$ 5,387,065	$ 5,739,658	$ 5,743,204
Total Recoverable OM&A from Appendix 2-JB [5]	$ 9,952,946	$ 12,205,885	$ 11,037,341	$ 11,277,823	$ 11,364,935	$ 11,596,240	$ 11,955,833
Number of Customers [2,4]	33,071	33,351	33,348	33,370	33,395	33,490	33,585
Number of FTEs [3,4]	87	87	89	84	85	86	84
Customers/FTEs	380.17	383.34	374.70	397.26	392.88	389.42	399.82
OM&A cost per customer							
O&M per customer	167.48	179.67	173.13	179.13	179.00	174.88	184.98
Admin per customer	133.48	186.31	157.85	158.83	161.31	171.38	171.01
Total OM&A per customer	300.96	365.98	330.97	337.96	340.32	346.26	355.99
OM&A cost per FTE							
O&M per FTE	63,670.73	68,874.93	64,869.75	71,161.88	70,327.88	68,099.80	73,959.87
Admin per FTE	50,744.10	71,422.60	59,145.31	63,097.92	63,377.24	66,740.21	68,371.48
Total OM&A per FTE	114,414.83	140,297.53	124,015.07	134,259.80	133,705.12	134,840.00	142,331.35

IAS 16 – Property, Plant & Equipment – Capitalization of Burdens was addressed in PUC Distribution's 2013 Cost of Service rate application. There are no increases or decreases in the test year relating to capitalized overhead.

OM&A Variance Analysis

A variance analysis was provided on the basis for cost drivers in Appendix 2-JB Recoverable OM&A Cost Driver Table in Table 4-11 above and attached as Appendix 2 to this Exhibit. In addition, identification in change of OM&A in test year in relation to change in capitalized overhead has been shown in Appendix 2-D, Table 4-13, below.

Table 4-13 – Overhead Expense

Appendix 2-D
Overhead Expense

Applicants are to provide a breakdown of OM&A before capitalization in the below table. OM&A before capitalization may be broken down by cost center, program, drivers or another format best suited to focus on capitalized vs. uncapitalized OM&A.

OM&A Before Capitalization	**2014 Historical Year**	**2015 Historical Year**	**2016 Historical Year**	**2017 Bridge Year**	**2018 Test Year**
Total OM&A Before Capitalization (B)	$ 12,900,367	$ 13,023,046	$ 12,985,961	$ 13,369,918	$ 13,625,799

Applicants are to provide a breakdown of capitalized OM&A in the below table. Capitalized OM&A may be broken down using the categories listed in the table below if possible. Otherwise, applicants are to provide its own break down of capitalized OM&A.

Capitalized OM&A	**2014 Historical Year**	**2015 Historical Year**	**2016 Historical Year**	**2017 Bridge Year**	**2018 Test Year**	**Directly Attributable? (Yes/No)**	**Explanation for Change in Overhead Capitalized**
Material	$ 270,974	$ 339,460	$ 300,712	$ 356,433	$ 363,562	Yes	
Engineering	$ 632,251	$ 564,975	$ 553,561	$ 607,495	$ 549,312	Yes	
Trucking	$ 595,906	$ 570,833	$ 491,515	$ 503,803	$ 513,879	Yes	
Supervisory	$ 363,896	$ 269,955	$ 275,237	$ 305,947	$ 243,213	Yes	
Total Capitalized OM&A (A)	$ 1,863,026	$ 1,745,223	$ 1,621,026	$ 1,773,677	$ 1,669,966		

% of Capitalized OM&A (=A/B)	14%	13%	12%	13%	12%		

2.4.3 Program Delivery Costs With Variance Analysis

PUC Distribution has a variety of programs, activities and initiatives that are imperative to provide safe, reliable and affordable service to customers. In Table 4-14 below, PUC Distribution has identified its programs and major functions on a comparative basis from 2013 Board Approved to the 2018 Test Year. This table is consistent with the Board's Appendix 2-JC, which can also be found in Appendix 3 to this Exhibit. These programs contribute to achieving the new Renewed Regulatory Framework performance outcomes of Customer Focus, Operational Effectiveness and Public Policy Responsiveness. This shows the alignment of PUC Distribution's direct costs and the management of the costs associated with the outcomes. An analysis is provided below on all material variances that exceed the materiality threshold for the 2018 Test Year versus the 2016 Actuals and the 2018 Test Year versus the 2013 Board Approved amounts.

Table 4-14 - OM&A Programs Table

Appendix 2-JC
OM&A Programs Table

Programs	Last Rebasing Year (2013 Board-Approved)	Last Rebasing Year (2013 Actuals)	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year	Variance (Test Year vs. 2016 Actuals)	Variance (Test Year vs. Last Rebasing Year (2013 Board-
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Operations									
Overhead Lines	$ 891,022	$ 886,027	$ 999,996	$ 833,710	$ 913,151	$ 977,516	$ 970,784	57,634	79,762
Underground Lines	$ 99,541	$ 103,879	$ 204,384	$ 194,355	$ 183,526	$ 157,706	$ 204,473	20,946	104,931
Operations Supervisory	$ 575,828	$ 677,616	$ 607,190	$ 661,003	$ 622,028	$ 649,055	$ 646,625	24,597	70,797
Load Dispatching	$ 255,221	$ 269,912	$ 252,338	$ 223,194	$ 232,038	$ 199,331	$ 214,485	-17,553	-40,736
Stations	$ 848,217	$ 905,156	$ 741,856	$ 747,612	$ 733,615	$ 798,954	$ 930,301	196,686	82,084
Transformers	$ 14,242	$ 8,202	$ 1,013	$ 3,984	$ 15,664	$ 17,276	$ 9,257	-6,408	-4,986
Meters	$ 423,008	$ 369,650	$ 319,706	$ 485,787	$ 550,630	$ 497,223	$ 584,371	33,742	161,364
Transmission	$ 1,136	$ 43,834	$ 38,620	$ 40,955	$ 50,381	$ 82,221	$ 83,563	33,182	82,427
Miscellaneous Operating	$ 452,096	$ 403,559	$ 397,481	$ 512,349	$ 470,320	$ 373,656	$ 382,197	-88,122	-69,899
Sub-Total	3,560,312	3,667,836	3,562,584	3,702,949	3,771,353	3,752,937	4,026,057	254,704	465,744
Maintenance									
Overhead Lines	$ 1,332,909	$ 1,688,546	$ 1,576,853	$ 1,288,038	$ 1,371,983	$ 1,343,956	$ 1,367,903	-4,080	34,994
Underground Lines	$ 258,634	$ 344,540	$ 306,555	$ 342,920	$ 360,487	$ 297,419	$ 304,847	-55,640	46,213
Stations	$ 265,799	$ 190,299	$ 243,581	$ 350,955	$ 345,773	$ 348,351	$ 339,888	-5,885	74,088
Transformers	$ 46,920	$ 22,017	$ 27,815	$ 211,054	$ 71,121	$ 32,374	$ 121,563	50,442	74,643
Meters	$ 74,143	$ 78,882	$ 56,018	$ 81,682	$ 57,154	$ 81,546	$ 52,372	-4,782	-21,770
Sub-Total	1,978,405	2,324,284	2,210,823	2,274,649	2,206,518	2,103,645	2,186,573	-19,946	208,168
Customer Service									
Bad Debt Expense	$ 107,680	$ 182,025	$ 127,593	$ 181,321	$ 378,852	$ 350,000	$ 261,613	-117,239	153,933
Customer Billing	$ 757,150	$ 811,476	$ 966,425	$ 888,033	$ 851,360	$ 914,837	$ 962,453	111,093	205,303
Customer Collections	$ 298,311	$ 280,607	$ 279,283	$ 348,403	$ 341,961	$ 354,038	$ 351,309	9,348	52,998
Community Relations	$ 544,548	$ 501,391	$ 557,701	$ 670,544	$ 626,657	$ 741,795	$ 618,800	-7,858	74,251
								0	0
Sub-Total	1,707,690	1,775,499	1,931,002	2,088,302	2,198,830	2,360,671	2,194,175	-4,655	486,486
Administration									
Income Tax	$ 50,202	$ 46,062	$ 40,740	$ 36,160	$ 31,755	$ 40,000	$ 45,000	13,245	-5,202
Insurance	$ 61,588	$ 147,363	$ 198,627	$ 205,612	$ 198,796	$ 131,136	$ 127,642	-71,154	66,054
LEAP	$ 19,054	$ 19,873	$ 22,610	$ 22,926	$ 23,270	$ 24,000	$ 24,000	730	4,946
Audit, Legal & Consulting	$ 116,025	$ 134,157	$ 230,840	$ 227,542	$ 139,566	$ 255,252	$ 209,185	69,619	93,160
Regulatory Affairs	$ 206,943	$ 297,503	$ 121,885	$ 149,856	$ 246,739	$ 350,292	$ 405,761	159,021	198,818
Building	$ 512,532	$ 2,005,468	$ 823,330	$ 653,778	$ 699,549	$ 653,602	$ 741,040	41,490	228,508
Administrative	$ 1,740,196	$ 1,787,842	$ 1,894,898	$ 1,916,048	$ 1,848,560	$ 1,924,705	$ 1,996,402	147,842	256,206
Sub-Total	2,706,539	4,438,267	3,332,931	3,211,923	3,188,235	3,378,987	3,549,028	360,793	842,489
Miscellaneous								0	0
Total	**9,952,946**	**12,205,886**	**11,037,340**	**11,277,823**	**11,364,937**	**11,596,241**	**11,955,833**	**590,896**	**2,002,887**

Materiality Threshold

In accordance with Chapter 2 Filing Requirements, an applicant must provide justification for changes from year to year to its rate base, capital expenditures and OM&A spending above a materiality threshold. PUC Distribution's materiality threshold is calculated as .5% of proposed base distribution revenue requirements for distributors with a revenue requirements greater than $10 million and less than or equal to $200 million. As such, PUC Distribution has selected the threshold of $110,400 for variance analysis.

Program Delivery Variance Analysis

Stations

Test Year vs 2016 actuals - $196,686

Areas of increase in Station operations in the 2018 Test Year over the 2016 Actual include, labour costs ($148,900), training ($16,500), building utilities ($26,500) and other immaterial variances ($4,786). As per the Independent Electric System Operator (IESO), "Market Participants must use the Reliability Compliance Tool to manage their compliance reporting requirements specified by the Ontario Reliability Compliance Program (ORCP)." PUC Distribution must be compliant with a total of eleven requirements from three different reliability standards. The three standards are: PRC-005-2(i), PRC-006-1 and PRC-008-0. The station maintenance and inspection program is based on a continuous cycle, with each of PUC Distribution's distribution stations being completed on a six year cycle and transmission stations being completed on a four year cycle. Staff resources and training have been increased in order to meet the standards.

Meters

Test Year vs Last Rebasing 2013 - $161,364

PUC Distribution Meter Department labour and vehicle costs have transitioned from capital to OM&A.

In addition, as part of a legislated requirement, PUC Distribution replaced approximately 30,000 electro-mechanical type revenue meters with electronic smart meters in 2009. The new electronic smart meters selected by PUC Distribution for use were manufactured by Sensus and had 10 year seal life and will expire in 2019. As per Measurement Canada (MC) requirements a meter with an expired seal cannot be left in service for revenue / billing purposes. MC's Statistical Method Specification (S-S-06) specification now places meter sampling and additional clerical data management and meter tracking responsibilities on the utility.

Bad Debt Expense

Test Year vs 2016 actuals – ($117,239)

PUC Distribution fell behind processing bad debts in 2014 and 2015, but made a concentrated effort in 2016 to bring write-offs up to date. Therefore bad debts in 2016 were higher than normal.

Test Year vs Last Rebasing 2013 - $153,933

Factors that contribute to the higher level of bad expense from the last rebasing are the economic uncertainty in Sault Ste. Marie and the increased cost of energy.

Customer Billing

Test Year vs 2016 actuals – $111,093

Increases in billing costs from 2016 actual to the test year include Postage ($44,000), training ($8,000) and billing software ($4,000) and other immaterial variances ($5,093). In addition PUC Distribution is required to change existing non interval meters for customers that are >50 kW which will increase MIST meter reading/communication costs by approximately $50,000 per year.

Test Year vs Last Rebasing 2013 - $205,303

Increases in billing costs from last rebasing to the test year include Postage ($61,600), training ($7,500), billing software ($9,700), wages and benefits ($7,000) and other immaterial variances ($497). PUC Distribution is required to change existing non interval meters for customers that are >50 kW which will increase MIST meter reading/communication costs by approximately $50,000 per year. The remainder of the cost increase relates to time of use billing costs which were underestimated by approximately $70,000 in the 2013 rebasing year.

Regulatory Affairs

Test Year vs 2016 actuals – $159,021

The increases in test year expenses over 2016 actuals include regulatory consultant fees to assist with the cost of service rate application ($82,000), additional staff time dedicated to the rate application ($72,000) and regulatory training ($3,500) and other immaterial variances ($1,521).

Test Year vs Last Rebasing 2013 - $198,818

The increases in test year expenses include increased OEB fees ($54,000), regulatory consultant fees to assist with the cost of service rate application ($120,000), additional staff time dedicated to the rate application ($15,000) and regulatory training ($3,500) and other immaterial variances ($6,318).

Building

Test Year vs Last Rebasing 2013 - $228,508

PUC Distribution’s new integrated office and service centre building was fully occupied in 2013. Increases from the last rebasing year to the test year include janitorial costs ($20,000), utilities ($135,000), property taxes ($224,000) and internal labour costs to service the building ($69,000) offset by an increased allocation of building costs to stores operations (-

$106,000), a reduction due not incurring costs for the former administrative building (-$110,000) and other immaterial variances ($3,492).

Administrative

Test Year vs 2016 actuals – $147,842

The increases in Administrative expense in the test year over 2016 actuals include an increase in management labour costs ($88,000) and asset utilization costs ($63,000) and other immaterial variances (-$3,158).

In addition to inflationary increases to salaries and wages, PUC Distribution added a Budget and Reporting Analyst to enhance the quantity and quality of information being provided to management allowing them to make informed decisions regarding their department and efficiency opportunities.

An increase to the allocation of the Asset utilization costs, in accordance with the shared services model described below in the Allocation Methodology section and in Exhibit 1 at section 2.3.1.9 of this Application.

Test Year vs Last Rebasing 2013 - $256,206

The increases in Administrative expense in the test year over the last rebasing year include an increase in management labour costs ($330,000), increased telephone fees ($28,000), reduced outside services (-$50,000) in Human Resources, IT and Health and Safety areas, and reduced postage (-$46,000) and other immaterial variances (-$5,794).

In addition to inflationary increases to salaries and wages, PUC Distribution added a Budget and Reporting Analyst to enhance the quantity and quality of information being provided to management allowing them to make informed decisions regarding their department and efficiency opportunities.

Transitional Costs for the VP Finance and CEO

The increased telephone fees are a result of the addition of the Interactive Voice Response System (IVR) which has enhanced customer communications and increased mobile phone plan costs in order to permit the office in a truck initiative.

Reduced outside services – effort to internally complete tasks rather than outsourcing

2.4.3.1. Workforce Planning and Employee Compensation

Compensation System

PUC Distribution has a long term service agreement with PUC Services for the operation of its distribution system. PUC does not have employees; however, in addition to regular salaries and wages, PUC Services offers the following compensation system to PUC Distribution equivalent employees.

Unionized Workers

Approximately 77% of PUC Distribution's workforce is unionized. The compensation for unionized employees is negotiated through the collective bargaining process and includes both office and trades workers represented by the Power Workers Union (PWU) Local Cupe 1000, in separate "Office" and "Outside" agreements.

PUC Distribution's collective agreements provide for annual payroll increases and employee step progressions. Labour rates and benefits are adjusted based on negotiated percentages as per the collective agreement. The commencement and expiry dates of PUC Distribution's current collective agreements are shown in Table 4-15 below. Table 4-16 shows the wage increases for management between 2012 and 2017.

Table 4-15 – Current Collective Agreements

Bargaining Unit	Contract Period	Wage Increase
PWU Office	May 1, 2011 to April 30, 2014	May 1, 2012: 2.8% May 1, 2013: 3.0%
PWU Outside	May 1, 2011 to April 30, 2014	May 1, 2012: 2.8% May 1, 2013: 3.0%
PWU Office	May 1, 2014 to April 30, 2018	May 1, 2014: 2.5% May 1, 2015: 2.8% May 1, 2016: 2.95% May 1, 2017: 3.0%
PWU Outside	May 1, 2014 to April 30, 2018	May 1, 2014: 2.5% May 1, 2015: 2.8% May 1, 2016: 2.95% May 1, 2017: 3.0%

Table 4-16 – Management Salary Increases

Management Increase	Period	Wage Increase
Management	2012 to 2017	2012: 2.8% 2013: 3.0% 2014: 2.5% 2015: 2.8% 2016: 0.9% 2017: 0.0%

The wage increase shown in the table above for each bargaining unit is applicable to each year of the contract. Each job classification in the collective bargaining agreements has a basic job description and a wage rate progression scale that increases from a minimum to a maximum rate.

A new collective agreement for both bargaining units is to begin on May 1, 2018.

Executive, Management & Non-Union Employees

Executive and Management compensation plan consists of salaries and benefits. Each position within the company has been placed on a pay scale which is reviewed periodically by senior management.

As with unionized employees, compensation for this group of employees provides for annual payroll increases and employee step progressions (for those employees below 100%) upon Board of Director approval.

Health Benefits

Employee benefit plans are to address the health and welfare of PUC Distribution's employees. There are separate benefits plans for active Management/Non-Union, PWU employees and retired employees. The PWU and retiree benefit plans are subject to change during the collective bargaining process, and the Management/Non-Union plan typically follows suit if improvements are awarded. Actuarial Valuations for PUC Services for years 2015 and 2017 are attached as Appendix 11.

Succession Planning

PUC Distribution has implemented succession planning prior to the Application and continues to monitor key employee retirement eligibility and employee intentions where known, in order to plan for the necessary employee succession.

The following summarizes Management's plans regarding succession vulnerability.

Powerline

PUC Distribution currently has a crew of qualified and experienced Powerline Technicians, with 5 out of 29 Powerline Technicians who can retire within the next five years. PUC Distribution has a sufficient number of qualified and experienced Powerline Technicians and will utilize apprenticeship programs to ensure adequate ability to fill vacancies as they occur.

Stations & Metering

PUC Distribution currently has a staff complement of 14 people within the stations and metering department, with 4 being eligible for retirement within the next five years. PUC Distribution will utilize apprenticeship programs to ensure adequate ability to fill vacancies as they occur.

Executive

The senior management team is at risk for impending retirements. Of the four Executive level staff (CEO and 3 VP's), one VP is retiring in 2018 while the other two VP's are within the potential retirement age and could retire within the next 5 years.

FTE & Employee Costs

As required, employee complement by FTE, compensation and benefits are set below in Table 4-17. This table is consistent with the Board Appendix 2-K and a copy can also be found in Appendix 4 to this Exhibit.

Table 4-17 – FTEs and Employee Costs (Appendix 2-K)

Appendix 2-K
Employee Costs

	Last Rebasing Year - 2013- Board Approved	Last Rebasing Year - 2013- Actual	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year
Number of Employees (FTEs including Part-Time)[1]							
Management (including executive)	19.42	18.35	18.58	18.15	19.75	20.19	19.10
Non-Management (union and non-union)	67.57	69.27	69.64	66.47	65.17	65.51	65.05
Total	86.99	87.61	88.22	84.63	84.91	85.70	84.16
Total Salary and Wages including ovetime and incentive pay							
Management (including executive)	$ 1,917,059	$ 1,980,372	$ 2,072,404	$ 1,999,948	$ 2,164,199	$ 2,264,896	$ 2,219,285
Non-Management (union and non-union)	$ 4,130,942	$ 5,239,956	$ 5,556,363	$ 5,181,452	$ 5,102,891	$ 5,321,163	$ 5,475,807
Total	$ 6,048,001	$ 7,220,328	$ 7,628,767	$ 7,181,400	$ 7,267,090	$ 7,586,059	$ 7,695,092
Total Benefits (Current + Accrued) [2]							
Management (including executive)	$ 429,613	$ 396,127	$ 475,333	$ 513,666	$ 585,139	$ 572,644	$ 562,869
Non-Management (union and non-union)	$ 1,617,450	$ 1,393,211	$ 1,414,264	$ 1,386,930	$ 1,401,771	$ 1,455,969	$ 1,445,296
Total	$ 2,047,063	$ 1,789,338	$ 1,889,597	$ 1,900,596	$ 1,986,910	$ 2,028,613	$ 2,008,164
Total Compensation (Salary, Wages, & Benefits)							
Management (including executive)	$ 2,346,672	$ 2,376,499	$ 2,547,737	$ 2,513,614	$ 2,749,338	$ 2,837,540	$ 2,782,154
Non-Management (union and non-union)	$ 5,748,392	$ 6,633,167	$ 6,970,627	$ 6,568,382	$ 6,504,662	$ 6,777,132	$ 6,921,103
Total	$ 8,095,064	$ 9,009,666	$ 9,518,364	$ 9,081,996	$ 9,254,000	$ 9,614,672	$ 9,703,257

PUC Distribution, through its affiliate PUC Services Inc. operates using a shared services model. PUC Distribution has no employees but rather relies on PUC Services to provide the necessary resources at cost to operate the distribution utility.

The number of employees shown above in Table 4-17 is based on the computation of the number of full time equivalent (FTE) positions throughout each of the fiscal years. Staff members hired by or resigning from PUC are prorated in that year as a portion of an FTE based on the hours worked. The FTE calculation is based on hours worked by PUC Services employees, including overtime hours that are directly and indirectly attributable to PUC. The table excludes Board of Directors and employees dedicated to non-rate regulated activities. PUC does not include hours for staff on short term disability or long term disability. The salaries and wages amounts include all salaries and wages paid, inclusive of incentive pay, overtime, vacation, holidays, sick leave, bereavement leave and other miscellaneous paid leaves.

The benefits amount comprise the employer's portion of statutory benefits, including CPP, EI, EHT and WSIB. In addition, benefit amounts comprise of the company's cost for providing: OMERS and other Employee Benefits as described in Table 4-19 - Employee Benefits Charged to OM&A and Capital below.

FTE, Wages & Benefits Variance Analysis

PUC Distribution completed the Board's Appendix 2-K, which is included above as Table 4-17. Table 4-18 below details employee costs from 2013 Board Approved through to the 2018 Test Year. All FTE's with their corresponding wages and benefits are included in the variance analysis below.

Table 4-18 - FTE and Employee Cost Variances

	2013 Board Approved vs 2013 Actual	2013 Actual vs 2014 Actual	2014 Actual vs 2015 Actual	2015 Actual vs 2016 Actual	2016 Actual vs 2017 Bridge	2017 Bridge vs 2018 Test
Number of Employees (FTEs including Part-Time)[1]						
Management (including executive)	- 1.07	0.23	- 0.43	1.59	0.44	- 1.08
Non-Management (union and non-union)	1.70	0.37	- 3.16	- 1.30	0.34	- 0.46
Total	0.62	0.60	- 3.59	0.29	0.78	- 1.54
Total Salary and Wages including ovetime and incentive pay						
Management (including executive)	63,313	$ 92,032	-$ 72,456	$ 164,251	$ 100,697	-$ 45,611
Non-Management (union and non-union)	1,109,014	$ 316,407	-$ 374,911	-$ 78,561	$ 218,272	$ 154,645
Total	$1,172,327	$ 408,439	-$ 447,367	$ 85,690	$ 318,969	$ 109,034
Total Benefits (Current + Accrued) [2]						
Management (including executive)	- 33,486	$ 79,206	$ 38,333	$ 71,473	-$ 12,495	-$ 9,775
Non-Management (union and non-union)	- 224,239	$ 21,053	-$ 27,334	$ 14,841	$ 54,198	-$ 10,673
Total	-$ 257,725	$ 100,259	$ 10,999	$ 86,314	$ 41,703	-$ 20,449
Total Compensation (Salary, Wages, & Benefits)						
Management (including executive)	$ 29,827	$ 171,238	-$ 34,123	$ 235,724	$ 88,202	-$ 55,386
Non-Management (union and non-union)	$ 884,775	$ 337,460	-$ 402,245	-$ 63,720	$ 272,469	$ 143,971
Total	$ 914,602	$ 508,698	-$ 436,368	$ 172,004	$ 360,672	$ 88,585

The FTE calculation is based on hours worked by PUC Services employees, including overtime hours that are directly and indirectly attributable to PUC Distribution.

Both of PUC Services' Management and Non-Management employees have seen small fluctuations since the Last Rebasing in 2013. Material changes in FTE's, salaries and wages, and benefits are as follows:

2013 Board Approved vs. 2013 Actual: (1.07) Management FTE; 1.70 Union FTE;

$1,172,327 Salary & Wages; ($257,725) Benefits

In addition to minor fluctuations in hours allocated to PUC Distribution, the FTE variance for 2013 includes:

Management

- Did not fill Smart Systems Analyst Job (1.0) FTE
- Aggregated non-material allocation in FTE reducing by (0.07) FTE

Union

- Engineering department transitions increase 1.06 FTE
- Did not fill GIS Tech position (0.50) FTE
- “After Hours” Operators allocated time to PUC increased 0.62 FTE
- Line department labour under allocated in 2013 BA – Lineman charged more time to PUC than in the 2013 BA increasing by 0.87 FTE
- Substation Electrician off on Short Term Disability decreasing by (0.30) FTE
- Aggregated non-material allocation in FTE reducing by (0.05) FTE

The salaries and wages variance of $1,172,327 was attributable to:

- Non-productive labour costs (i.e. vacations, holidays, sick time, and bereavement) were included in the Total Benefit amount for the 2013 Board Approved ($437,166). In the 2013 Actuals, these costs are included in Total Salary and Wages.
- Allocated labour dollars for the Stores Department ($132,429) and Fleet Mechanics ($103,264) were not included in Salaries and Wages in the 2013 Board Approved

amounts as these costs are allocated though material and trucking costs but was included in the 2013 Actuals.

- Overtime costs in the Line and Engineering Departments were increased in 2013 ($451,237) due in part to the Bell FTTH Project and higher than expected storm repairs.

The benefit variance of ($257,725) was attributable to:

- Non-productive labour costs (i.e. vacations, holidays, sick time, and bereavement) were included in the Total Benefit amount for the 2013 Board Approved ($437,166). In the 2013 Actuals, these costs are included in Total Salary and Wages.
- As an offset to the reduction noted above, the allocation of benefit costs are increased ($179,441) due to the increases to Salaries and Wages, described above.

2013 Actual vs. 2014 Actual: 0.23 Management FTE; 0.37 Union FTE; $408,440 Salary & Wages

In addition to minor fluctuations in hours allocated to PUC Distribution, the FTE variance for 2014 includes:

Management

- Addition of a Facilities Supervisor increasing by 0.44 FTE
- Overlap for the Billing Supervisor replacement increasing by 0.33 FTE
- Regulatory staff time not allocated to PUC reduced by (0.19) FTE
- Aggregated non-material allocation in FTE reducing by (0.35) FTE

Union

- Substation Electrician returned from Short Term Disability increasing by 0.31 FTE
- Overlap for the System Operator position replacement increasing by 0.36 FTE
- Aggregated non-material allocation in FTE increasing by (0.30) FTE

In addition to regular inflationary increases applied to salaries and wages, the labour variance of $408,440 was also attributable to:

- addition of a Facilities Supervisor position
- overlap during the transition of the Billing Supervisor
- Return of Substation Electrician position from Short Term Disability
- Increased overtime from the Bell FTTH Project

2014 Actual vs. 2015 Actual: (0.43) Management FTE; (3.16) Union FTE; ($447,367) Salary & Wages

In addition to minor fluctuations in hours allocated to PUC Distribution, the FTE variance for 2015 includes:

Management

- Addition of a Communications Supervisor accountable for customer engagement and internal and external corporate communication increasing by 0.55 FTE
- Temporary contract position in Finance eliminated reducing by (0.33) FTE
- Overlap for the Billing Supervisor replacement eliminated reducing by (0.52) FTE
- Aggregated non-material allocation in FTE reducing by (0.13) FTE

Union

- Reduction of FTE in the corporate labour pool and in Stores who allocated time to water main breaks reducing by (1.90) FTE
- Overlap for the System Operator position replacement eliminated reducing by (0.66) FTE
- Engineering FTE rate reduced due to work not related to PUC Distribution being completed and the ending of a contract worker reducing by (0.68) FTE
- Safety and Environment Office Assistant – Added in 2015 increasing by 0.12 FTE
- Aggregated non-material allocation in FTE reducing by (0.04) FTE

In addition to regular inflationary increases applied to salaries and wages, the labour variance of ($447,367) was also attributable to:

- Reduced overtime on the Bell FTTH Project
- Engineering salaries allocated to non PUC Distribution related work

2015 Actual vs. 2016 Actual: 1.59 Management FTE; (1.30) Union FTE

In addition to minor fluctuations in hours allocated to PUC Distribution, the FTE variance for 2016 includes:

Management

- Manager – Conservation, Facilities & Fleet position added as three departments merged into one increasing by 0.5 FTE
- Temporary Admin Assistant position added increasing by 0.33 FTE
- HR Admin Assistant retirement transition overlap increasing by 0.14 FTE

- Protection and Control Engineer allocation of time increasing by 0.24
- Aggregated non-material allocation in FTE increasing by 0.38 FTE

Union

- Line department Power Line Technician reduced by (0.88) FTE
- Locates department – employee off due to sickness reducing (0.28) FTE
- Fleet Services Technician position added increasing by 0.5 FTE
- Engineering allocation to LED Streetlights project reduced by (0.57) FTE
- Aggregated non-material allocation in FTE reducing by (0.07) FTE

2016 Actual vs. 2017 Bridge: 0.44 Management FTE; 0.34 Union FTE; $318,969 Salary & Wages

In addition to minor fluctuations in hours allocated to PUC Distribution, the FTE variance for 2017 includes:

Management

- Supervisor of Billing position was removed in 2017 reducing by (0.51) FTE
- Lines Manager retirement transition overlap increasing by 0.35 FTE
- Stations & Metering Manager retirement transition overlap increasing by 0.48 FTE
- Addition of a Budgeting and Reporting Analyst increasing by 0.44 FTE
- Temporary Admin Assistant position removed reducing by (0.40) FTE

- Aggregated non-material allocation in FTE increasing by 0.08 FTE

Union

- Substation Electrician position added increasing by 1.0 FTE
- Reduction of a Power Line Technician positions reduced by (0.72) FTE
- Aggregated non-material allocation in FTE increasing by 0.06 FTE

In addition to regular inflationary increases applied to salaries and wages, the labour variance of $318,969 was also attributable to:

- Multiple staff replacements with overlap for training purposes including;
  - Lines Manager
  - Stations & Metering Manager
- Addition of a Budgeting and Reporting Analyst position
- Elimination of the Billing Supervisor position
- Substation Electrician position added to replace retirement of a Substation Electrician in 2016

2017 Bridge vs. 2018 Test: (1.08) Management FTE; (0.46) Union FTE

In addition to minor fluctuations in hours allocated to PUC Distribution, the FTE variance for 2018 includes:

Management

- Reduction of overlap due to multiple staff replacements for training purposes including;

    - Lines Manager reduced by (0.35) FTE
    - Stations & Metering Manager reduced by (0.48) FTE
- Retirement of the Manager of Customer Engagement & Locates which was not replaced reduced by (0.55) FTE
- Retirement of the Director of Safety & Environment which was not replaced reduced by (0.45) FTE
- Addition of a Regulatory Assistant position increasing by 0.72 FTE
- Staff replacements with overlap for training purposes including;
    - President and CEO increasing 0.45 FTE
    - VP, Finance and Corporate Support increasing by 0.24 FTE
- Aggregated non-material allocation in FTE increasing by 0.06 FTE

Union

- Addition of a Substation Electrician position increasing by 1 FTE
- Elimination of the Dispatcher position reducing by (0.50) FTE
- Elimination of Engineering Technician position reducing by (0.42) FTE
- ”After Hours” Operator FTE overlap eliminated in 2018 reducing by (0.59) FTE
- Aggregated non-material allocation in FTE increasing by 0.05 FTE

Incentive Based Pay

PUC Services seeks to encourage an incentive based performance culture by aligning employees' efforts with corporate vision and the short and long term goals of PUC Distribution. At present, an incentive based pay system exists for all non-union employees excluding the President and CEO. PUC Distribution supports the Balanced Scorecard methodology in setting corporate and individual goals to foster continuous improvement and cost reductions that support a healthy balance sheet that provides value to customers by keeping rates reasonable.

Executive Pay

PUC Services' executive pay philosophy considers compensation from throughout Ontario at other like-sized or similarly structured utilities, ensuring that executives are compensated at levels consistent with comparable organizations. Such compensation levels are reviewed on a regular basis and benchmarked against the MEARIE Group Management Salary Survey administered by Korn Ferry Hay Group. The executive group salaries, a portion of which are allocated to PUC Distribution, are at or near the average of the LDCs surveyed.

Benefits

A comprehensive and competitive benefits package exists which includes medical and dental insurance, life insurance, vacation and leave policies and a company sponsored retirement plan.

The plans are designed to address the health and welfare needs of the employee population. The benefit packages are consistent across the organization for 190 employees, including the executive team. The only inconsistencies are life insurance coverage (non-union staff receive 2 times current base salary versus union staff receive 1.5 time's current base salary and a health care spending account for non-union employees.

Employee Benefit Programs

PUC Distribution has a long term service agreement with PUC Services for the operation its distribution system. PUC does not have employees; however, PUC Services offers the following benefits to PUC Distribution equivalent employees:

- Ontario Municipal Employee Retirement Savings ("OMERS") – PUC Services remits 9% on the first $54,900 of earnings (subject to various inclusions and exclusions) and 14.6% of earnings thereafter (also subject to various inclusions and exclusions).
- Lone Term Disability ("LTD") – PUC Services benefit provider is Medavie Blue Cross. PUC Services' premiums cover current employees until age 65.
- Life Insurance Benefits – PUC Services benefit provider is Medavie Blue Cross and is in place until age 65.
- Health Care & Dental Benefits – PUC Services benefit provider is Medavie Blue Cross and is in place until age 65.
- Employee & Family Assistance Program (EFAP) – this program is offered through a local provider, Group Health Centre, and assists employees and their immediate family members in assessing and resolving work, health and life issues.

OMERS Pension Plan

PUC Services employees are members of the Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer pension plan in which most Ontario LDCs participate. As such, PUC Services pension benefit costs are consistent with other participating Ontario LDCs. While OMERS is a Defined Benefit plan, for accounting purposes it is effectively treated as a Defined Contribution plan by the participating distributors including PUC Services. This means that the annual employer contributions made to the plan are the same as the accrual accounting expense recorded for financial statement purposes. Pension premium information from 2012 to 2016 Actual and 2017

Bridge Year and 2018 Test Year can be found in Table 4-19 Employee Benefits Charged to OM&A and Capital below. For the 2018 Test Year, PUC assumed OMERS rates of 9.0% on earning up to the Year's Maximum Pensionable Earnings (YMPE) limits and 14.6% on earning over YMPE limits. The 2017 YMPE is $55,300 and the 2018 YMPE is $55,900.

Employee Future Benefits

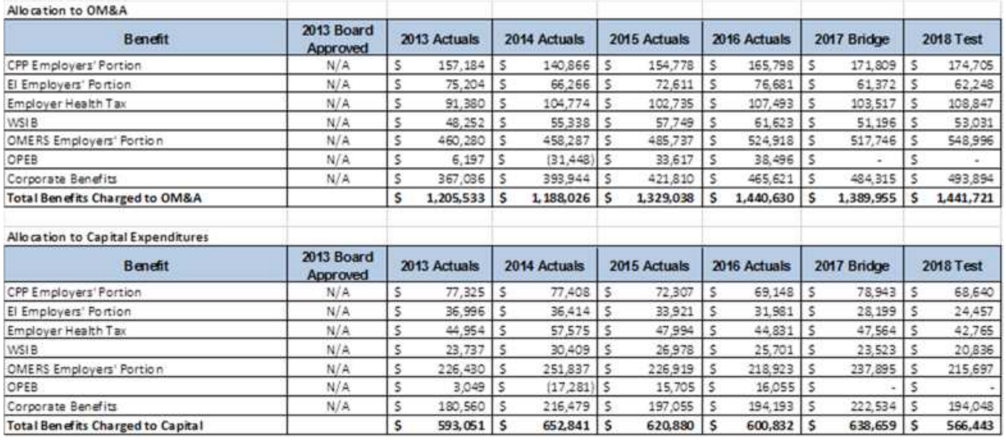
PUC Services provides post-employment benefit life insurance and health care to retirees under the age of 65 through a group defined benefit plan.

The cost of post-employment benefits are actuarially determined using the projected benefit method prorated on service and based on assumptions that reflect management 's best estimates. The current service cost for the period is equal to the employee's service rendered in the period. Past service costs from the plan amendments are amortized on a straight line basis over the average remaining service period of the employee's active date of amendment.

PUC Services recovers their OPEB costs based on the accrual method. This method recognizes the cost of OPEBs as an employee's service is rendered and the benefit is earned. PUC Distribution's shared portion of the accrued amount is allocated as an overhead on direct labour on an annual basis. As such, PUC Distribution's obligation for OPEBs is treated similar to pension funding where there is no future obligations.

As noted above, PUC Distribution does not have employees, therefore an actuary report of PUC Services is included as Attachment [●].

Table 4-19 - Employee Benefits Charged to OM&A and Capital



Allocation to OM&A

Benefit	2013 Board Approved	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge	2018 Test
CPP Employers' Portion	N/A	$ 157,184	$ 140,866	$ 154,778	$ 165,798	$ 171,809	$ 174,705
EI Employers' Portion	N/A	$ 75,204	$ 66,266	$ 72,611	$ 76,681	$ 61,372	$ 62,248
Employer Health Tax	N/A	$ 91,380	$ 104,774	$ 102,735	$ 107,493	$ 103,517	$ 108,847
WSIB	N/A	$ 48,252	$ 55,338	$ 57,749	$ 61,623	$ 51,196	$ 53,031
OMERS Employers' Portion	N/A	$ 460,280	$ 458,287	$ 485,737	$ 524,918	$ 517,746	$ 548,996
OPEB	N/A	$ 6,197	$ (31,448)	$ 33,617	$ 38,496	$ -	$ -
Corporate Benefits	N/A	$ 367,036	$ 393,944	$ 421,810	$ 465,621	$ 484,315	$ 493,894
Total Benefits Charged to OM&A		**$ 1,205,533**	**$ 1,188,026**	**$ 1,329,038**	**$ 1,440,630**	**$ 1,389,955**	**$ 1,441,721**

Allocation to Capital Expenditures

Benefit	2013 Board Approved	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge	2018 Test
CPP Employers' Portion	N/A	$ 77,325	$ 77,408	$ 72,307	$ 69,148	$ 78,943	$ 68,640
EI Employers' Portion	N/A	$ 36,996	$ 36,414	$ 33,921	$ 31,981	$ 28,199	$ 24,457
Employer Health Tax	N/A	$ 44,954	$ 57,575	$ 47,994	$ 44,831	$ 47,564	$ 42,765
WSIB	N/A	$ 23,737	$ 30,409	$ 26,978	$ 25,701	$ 23,523	$ 20,836
OMERS Employers' Portion	N/A	$ 226,430	$ 251,837	$ 226,919	$ 218,923	$ 237,895	$ 215,697
OPEB	N/A	$ 3,049	$ (17,281)	$ 15,705	$ 16,055	$ -	$ -
Corporate Benefits	N/A	$ 180,560	$ 216,479	$ 197,055	$ 194,193	$ 222,534	$ 194,048
Total Benefits Charged to Capital		**$ 593,051**	**$ 652,841**	**$ 620,880**	**$ 600,832**	**$ 638,659**	**$ 566,443**

2.4.3.2 Shared Services and Corporate Cost Allocation

PUC Distribution is a virtual utility. All of its costs are shared corporate services as defined in the Affiliate Relationship Code. The following Tables 4-20 through 4-33 details the corporate cost allocation for each year in the historic period as well as the test year. These tables are followed by a description of the allocation methodology and variance analysis.

Table 4-20 – Shared Services and Corporate Cost Allocation for 2013 BA

Appendix 2-N
Shared Services and Corporate Cost Allocation [1]

Year: 2013 Approved

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	**To**			**$**	**$**
PUC Distribution	PUC Services	Building rental		$ -	$ -

Table 4-21– Shared Services and Corporate Cost Allocation for 2013 Actual

Year: 2013 Actual

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	**To**			**$**	**$**
PUC Distribution	PUC Services	Building rental - 2013	Cost - no markup	$2,281,174.80	$2,281,174.80

Table 4-22 – Shared Services and Corporate Cost Allocation for 2014 Actual

Year: 2014 Actual

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	**To**			**$**	**$**
PUC Distribution	PUC Services	Building rental - 2014	Cost - no markup	$1,246,600.41	$1,246,600.41

Table 4-23 – Shared Services and Corporate Cost Allocation for 2015 Actual

Year: 2015 Actual

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	**To**			**$**	**$**
PUC Distribution	PUC Services	Building rental - 2015	Cost - no markup	$1,240,120.24	$1,240,120.24

Table 4-24 – Shared Services and Corporate Cost Allocation for 2016 Actual

Year: 2016 Actual

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	**To**			**$**	**$**
PUC Distribution	PUC Services	Building rental - 2016	Cost - no markup	$1,293,858.00	$1,293,858.00

Table 4-25 – Shared Services and Corporate Cost Allocation for 2017 Bridge Year

Year: 2017 Bridge Year

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
PUC Distribution	PUC Services	Building rental - 2017	Cost - no markup	$1,332,390.95	$1,332,390.95

Table 4-26 – Shared Services and Corporate Cost Allocation for 2018 Test Year

Year: 2018 Test Year

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
PUC Distribution	PUC Services	Building rental - 2018	Cost - no markup	$1,334,160.93	$1,334,160.93

Table 4-27 – Shared Services and Corporate Cost Allocation for 2013 BA

Year: 2013 approved

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
PUC Services	PUC Distribution	Billing Acct 5305 to 5315	Cost - no markup	56.00%	$514,918
PUC Services	PUC Distribution	Collections Acct 5320 to 5335	Cost - no markup	56.00%	$271,543
PUC Services	PUC Distribution	Customer Services Acct 5405 to 5420	Cost - no markup	56.00%	$525,651
PUC Services	PUC Distribution	Admin Acct 5605 to 5635, 5665, 5675	Cost - no markup	45.71%	$2,299,422
					$3,611,533

Table 4-28 – Shared Services and Corporate Cost Allocation for 2013 Actual

Year: 2013 Actual

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	**To**			**%**	**$**
PUC Services	PUC Distribution	Billing Acct 5305 to 5315	Cost - no markup	56.00%	$394,555
PUC Services	PUC Distribution	Collections Acct 5320 to 5335	Cost - no markup	74.00%	$237,502
PUC Services	PUC Distribution	Customer Services Acct 5405 to 5420	Cost - no markup	56.00%	$403,080
PUC Services	PUC Distribution	Admin Acct 5605 to 5635, 5665, 5675	Cost - no markup	45.71%	$3,760,722
					$4,795,859

Table 4-29 – Shared Services and Corporate Cost Allocation for 2014

Year: 2014

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	**To**			**%**	**$**
PUC Services	PUC Distribution	Billing Acct 5305 to 5315	Cost - no markup	56.00%	$506,728
PUC Services	PUC Distribution	Collections Acct 5320 to 5335	Cost - no markup	74.00%	$238,375
PUC Services	PUC Distribution	Customer Services Acct 5405 to 5420	Cost - no markup	56.00%	$475,209
PUC Services	PUC Distribution	Admin Acct 5605 to 5635, 5665	Cost - no markup	42.31%	$1,852,229
PUC Services	PUC Distribution	Building Acct 5675	Cost - no markup	46.45%	$823,324
					$3,895,865

Table 4-30 – Shared Services and Corporate Cost Allocation for 2015

Year: 2015

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	**To**			**%**	**$**
PUC Services	PUC Distribution	Billing Acct 5305 to 5315	Cost - no markup	56.00%	$537,963
PUC Services	PUC Distribution	Collections Acct 5320 to 5335	Cost - no markup	74.00%	$287,187
PUC Services	PUC Distribution	Customer Services Acct 5405 to 5420	Cost - no markup	56.00%	$583,187
PUC Services	PUC Distribution	Admin Acct 5605 to 5635, 5665	Cost - no markup	42.31%	$1,867,667
PUC Services	PUC Distribution	Building Acct 5675	Cost - no markup	46.45%	$653,778
					$3,929,783

Table 4-31 – Shared Services and Corporate Cost Allocation for 2016

Year: 2016

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	**To**			**%**	**$**
PUC Services	PUC Distribution	Billing Acct 5305 to 5315	Cost - no markup	56.00%	$477,914
PUC Services	PUC Distribution	Collections Acct 5320 to 5335	Cost - no markup	74.00%	$264,047
PUC Services	PUC Distribution	Customer Services Acct 5405 to 5420	Cost - no markup	56.00%	$552,394
PUC Services	PUC Distribution	Admin Acct 5605 to 5635, 5665	Cost - no markup	42.31%	$1,695,803
PUC Services	PUC Distribution	Building Acct 5675	Cost - no markup	46.45%	$699,549
					$3,689,707

Table 4-32 – Shared Services and Corporate Cost Allocation for 2017 Bridge

Year: 2017 Bridge

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	**To**			**%**	**$**
PUC Services	PUC Distribution	Billing Acct 5305 to 5315	Cost - no markup	56.00%	$553,232
PUC Services	PUC Distribution	Collections Acct 5320 to 5335	Cost - no markup	74.00%	$282,863
PUC Services	PUC Distribution	Customer Services Acct 5405 to 5420	Cost - no markup	56.00%	$637,503
PUC Services	PUC Distribution	Admin Acct 5605 to 5635, 5665	Cost - no markup	41.31%	$1,856,868
PUC Services	PUC Distribution	Building Acct 5675	Cost - no markup	46.45%	$652,802
					$3,983,268

Table 4-33 – Shared Services and Corporate Cost Allocation for 2018 Test

Year: 2018 Test

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	**To**			**%**	**$**
PUC Services	PUC Distribution	Billing Acct 5305 to 5315	Cost - no markup	56.00%	$566,235
PUC Services	PUC Distribution	Collections Acct 5320 to 5335	Cost - no markup	74.00%	$294,605
PUC Services	PUC Distribution	Customer Services Acct 5405 to 5420	Cost - no markup	56.00%	$524,535
PUC Services	PUC Distribution	Admin Acct 5605 to 5635, 5665	Cost - no markup	41.31%	$1,847,687
PUC Services	PUC Distribution	Building Acct 5675	Cost - no markup	46.45%	$740,240
					$3,973,302

Allocation Methodology

PUC Services Inc. provides billing, collection, customer service, and administration services to the affiliated group 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 below. It should be noted that any cost that can be directly associated with a specific company or contract is charged to that company or contract, as a pass-through to that company at cost.

KPMG reviewed PUC Services' method for allocating shared services in the fall of 2001. The review included consideration that the method determining cost allocation must be appropriate for many different users such as the OEB, Canada Customs and Revenue Agency, the Corporation of the City of Sault Ste. Marie and the affiliated companies. The areas identified for allocation were billing, collecting, customer service, and administration. A number of possible cost drivers were identified including: number of customers, number of bills generated, total relative expenditures before allocated costs, square footage, number of employees, service revenues, asset value, etc. The following allocators/cost drivers in Table 4-34 were recommended at the time:

Table 4-34 - Cost Drivers and Allocators

Area	**Allocator**
Billing	Number of Customers
Collecting	Number of Customers
Customer Service	Number of Customers
Administration	Service Revenue

The allocation factors were internally reviewed on an annual basis up to the year ended December 31, 2006 for reasonableness and changing circumstances.

In preparation for the 2008 Cost of Service rate filing, and in response to the concerns expressed by the Board in its Decision and Order regarding PUC Distribuion's 2006 rates, a consultant was engaged to review processes related to charging of shared services costs to the affiliated companies from PUC Services. RDI Consulting Inc.'s Full Absorption Cost Allocation Report was filed with PUC Distribution's 2008 Cost of Service Rate Application (attached as Appendix 9). There have been two changes in the allocation method from the RDI report. Commencing in 2012 no portion of the administrative expenses has been allocation to the capital as a result IFRS. In addition, commencing in 2014 the allocation method for building costs were split from Administrative costs and allocated based on the portion of the building used by each of the occupants. The allocation percentages have been reviewed annually and have been adjusted due to any changed circumstances such as the divestiture of PUC Telecom.

The following Table 4-35 details the allocation percentages to the affiliates for each of the shared services.

Table 4-35 - Allocations to Affiliates

	Allocator	PUC Distribution	PUC Services	Public Utilities Commission	Total
Allocation to Affiliates					
Billing	# of Customers	56%		44%	100%
Collections	# of Customers	56%		44%	100%
Customer Service	# of Customers	56%		44%	100%
Administrative	Labour related effort	42%	16%	42%	100%
Building	% of building utilized	46%	46%	8%	100%

Shared Services and Corporate Cost Allocation - Variance Analysis

The following Table 4-36 details the variance analysis of the shared services and corporate cost allocation.

Table 4-36 - Shared Services and and Corporate Cost Allocation Variance Analysis

	Years				
Service Offered	**2013 Board Approved**	**2016 Actual**	**2018 Test**	**Test Year vs. Last Actual ($)**	**Test Year vs. Board Approved ($)**
Billing	$ 425,073	$ 477,914	$ 566,235	$ 88,321	$ 141,162
Collections	$ 257,666	$ 264,047	$ 294,605	$ 30,558	$ 36,939
Customer Service	$ 392,125	$ 552,394	$ 524,535	-$ 27,859	$ 132,410
Administrative	$ 1,669,818	$ 1,695,803	$ 1,847,687	$ 151,884	$ 177,869
Building	$ 512,532	$ 699,549	$ 740,240	$ 40,691	$ 227,708
Building Accounting Change					
Total	**$ 3,257,214**	**$ 3,689,707**	**$ 3,973,302**	**$ 283,595**	**$ 716,088**

Billing

Test Year vs. Board Approved

Increases from the 2013 rebase to the 2018 test year include postage ($62,000), wages ($50,000) as a result in an increase to the allocation of time to joint expenses that was offset by a reduction in direct charges to PUC, software ($8,000), billing printer lease ($4,000), mail inserting equipment maintenance ($4,000) and training ($8,000).

Customer Service

Test Year vs. Board Approved

Increases from the 2013 rebase to the 2018 test year include software ($26,000), wages ($111,000) as a result of in an increase in resources for customer engagement including the addition of a Communication Supervisor tasked with supporting the customer engagement initiative.

Administrative

Test Year vs. Last Actual

Increases from the last actual to test year include: software ($47,000), telephone ($27,000), training ($20,000) and wages ($52,000). The wage change includes the transition for the CEO and VP Finance, addition of a Budget and Reporting Analyst offset by reductions to the Director of Safety and Environment and temporary administrative assistant.

Test Year vs. Board Approved

The increase from the Board approved to test year is in the area of wages ($172,000). The increase includes general wage rate increases over the five year period, the transition for the CEO and VP Finance positions, and the addition of a Budget and Reporting Analyst. These increases are offset by the reduction to the Director of Safety and Environment.

Building

Test Year vs. Board Approved

PUC Distribution’s new integrated office and service centre building was fully occupied in 2013. Increases from the last rebasing year to the test year include janitorial costs ($20,000), utilities ($135,000), property taxes ($224,000) and internal labour costs to service the building ($69,000) offset by an increased allocation of building costs to stores operations (-$106,000) and a reduction due not incurring costs for the former administrative building (-$110,000).

Shared Services from Affiliates

Affiliate Board Of Director Costs

There are no Board of Director costs from any of PUC's affiliates included in PUC Distribution's costs.

2.4.3.3. Purchases of Non-Affiliate Services

PUC Distribution's purchasing policy establishes the principles, requirements, accountabilities and guidelines for the purchase of goods and services. A copy of the purchasing policy is attached. PUC Distribution confirms that it is in compliance with the Purchasing Policy. Table 4-37 below lists PUC Distribution's purchases that exceeded the materiality threshold in 2013, 2014, 2015, 2016 and 2017. PUC Distribution anticipates using the same vendors for 2018, however new suppliers are continuously being sourced. Occasionally it is necessary to obtain services or products utilizing a single or sole process. The details of the single/sole source process is included in the attached purchasing policy as Appendix 6.

Table 4-37 – Vendor Purchases

Line No.	Vendor Number	Vendor Name	Product/Service	Method of Selection	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge
1	00069	STELLA-JONES INC - GUELPH UTIL	Wood Poles	Competitive Bid	$188,146.13	$256,837.70	$247,525.37	$190,594.84	$208,716.65	$133,387.46
2	00070	GUILLEVIN INTERNATIONAL	PVC,Safety Items, Tools	Competitive Bid	$195,725.79	$250,550.96	$211,618.67	$151,574.86	$149,032.72	$113,288.64
3	00105	NEDCO DIVISION OF REXEL	Misc Elect products/wire	Competitive Bid	$125,264.75		$233,854.41			
4	00117	PALMER CONSTRUCTION GROUP	Vaccum Truck Rent	Competitive Bid		$133,413.22				
5	00149	S & C ELECTRIC CAN LTD	Switchgear	Competitive Bid	$208,725.60	$264,226.62				$234,150.34
6	00214	S & T ELECTRICAL	Misc Electrical work	Competitive Bid	$129,452.96	$1,577,318.22	$401,487.09			
7	00229	S S MARIE INNOVATION CENTRE	GIS Services	Sole Source	$320,420.22	$290,510.33	$315,422.73	$361,181.06	$376,869.41	$353,672.89
8	00231	ERGO OFFICE PLUS	Office Supplies/Furniture	Competitive Bid	$227,389.35	$240,779.28	$112,251.62			
9	00272	ABB INC.	Substation Transformers	Competitive Bid	$216,494.44	$113,668.96	$316,631.65			
10	00292	GENERAL ELECTRIC CANADA	Breaker & Trx Repair	Competitive Bid		$383,221.60	$140,691.22			
11	00360	SURVALENT TECHNOLOGY	Scada software	Competitive Bid	$225,909.60					
12	00389	MGP ARCHITECTS ENGINEER	Architect Services	Competitive Bid	$516,292.17	$115,861.25				
13	00397	POLE CARE INTERNATIONAL	Pole Testing	Competitive Bid	$136,242.86	$127,645.86	$125,542.09			
14	00422	ONTARIO ENERGY BOARD	OEB Fees	Regulated				$121,181.74	$160,609.88	$158,227.46
15	00451	CITY OF SAULT STE MARIE	Wilson St. Construction	Competitive Bid	$130,176.65					
16	00544	SIEMENS CANADA LIMITED	Sub 10 - 12kV Switchgear	Competitive Bid		$305,746.36				
17	00561	ANIXTER POWER SOLUTIONS (HD)	TRX and Pole Line Hardw	Competitive Bid	$1,302,421.71	$1,516,808.40	$1,121,095.60	$1,065,680.68	$1,146,550.54	$933,441.19
18	00819	COSTELLO ASSOCIATES	Scada software	Competitive Bid	$125,535.78					
19	00858	BELL CANADA -PREV. BELL ALIANT	Pole Attachements	Regulated		$126,002.07	$112,225.55		$119,706.50	$133,264.69
20	00875	WSP CANADA INC.	Sub 16 Rebuild	Competitive Bid					$120,156.02	$215,978.85
21	01017	RODAN ENERGY & METERING	Wholesale Meters	Competitive Bid	$122,751.57					
22	01040	DOUBLE S CONSTRUCTION	Underground House Serv	Competitive Bid	$183,787.67					
23	01124	EATON ELECTRICAL GROUP	Sub 1 -Testing and Comm	Competitive Bid		$132,040.50				
24	01137	ASCENT (FORMERLY TILTRAN)	Switch, Fibre, Cable Inst	Competitive Bid	$151,758.19					
25	01197	WILDERNESS ENVIRONMENTAL	Line Clearing	Competitive Bid				$563,344.80		
26	01241	PICKARD CONSTRUCTION	Equip Rental/Services	Competitive Bid			$176,101.15	$212,741.98	$192,360.81	$114,132.86
27	01326	NEDCO	Misc Elect products/wire	Competitive Bid	$469,513.32	$604,163.28	$454,471.55			
28	01334	VIRELEC LTD.	Substation Relay Rep	Competitive Bid		$702,352.42	$121,404.41			
29	01356	CY RHEAULT CONSTRUCTION LTD.	Contractor - new building	Competitive Bid	$18,144,602.62	$3,780,904.24				
30	01404	ASPLUNDH CANADA ULC	Line Clearing	Competitive Bid	$441,347.42	$672,214.94	$782,870.33		$604,319.80	$570,488.84
31	01419	PINCHIN LTD.	Environmental Services	Single Source				$156,387.83		
32	01434	IBI GROUP	Sub10 Rebuild-Eng Serv	Competitive Bid	$173,522.81					
33	01460	NOVINIUM	Cable Injection	Competitive Bid	$123,396.88					
34	01485	ASCENT	Breaker	Competitive Bid	$137,569.14					
35	01629	EPTCON LTD.	TSI Substation Work	Competitive Bid		$313,085.82	$361,294.17	$176,968.18		
36	01742	CUSTOMER FIRST INC.	Pilot Program Develop	Joint project with other LDCs				$118,654.65		$228,147.00
37	01832	COOPER INDUSTRIES (ELEC) INC	Voltage Regulators	Competitive Bid				$165,080.12		
38	01905	S & T GROUP	Customer Demand	Competitive Bid						$317,937.16
					$23,996,447.63	**$11,907,352.03**	**$5,234,487.61**	**$3,283,390.74**	**$3,078,322.33**	**$3,506,117.38**

2.4.3.4. One-Time Costs

PUC Distribution has included on-time costs of $130,000 in its 2018 test year revenue requirement based on a five year recovery until the next cost of service Application. Details of this one-time cost recovery are in the following section.

2.4.3.5. Regulatory Costs

PUC Distribution's regulatory staff reports to the Finance Division and is staffed by the Rates and Regulatory Affairs Officer, who is responsible for preparing regulatory filings and rate applications, performing settlement reviews and reconciliations, ensuring regulatory and legislative compliance, performing business and process reviews, participating in regulatory consultations and providing reporting and timely responses to regulatory bodies.

PUC Distribution has included the costs associated with the Application in the revenue requirement. Annual ongoing costs include the OEB assessment ($160,000), section 30 costs, miscellaneous regulatory and training costs ($23,000), and staff resources ($93,000) allocated to regulatory matters. Costs that are not incurred annually totalling $585,000 have been spread over the 5 year rate period and have been included in test year expenses at $130,000 per year. One-time costs include consulting costs for legal and consulting assistance from experienced subject matter experts.

Table 4-38 below details the components of one time costs.

Table 4-38 PUC Distribution One Time Costs

Service	Cost	# of Occurrences in Rate Period	Expense Included in Test Year
Legal and rates consulting expenses to complete the application	$300,000	1	$60,000
Services related to the Distribution System Plan and Asset Management Plan	$100,000	1	$20,000
Customer engagement services	$30,000	1	$6,000
Legal and rates consulting expenses for the settlement conference	$50,000	1	$10,000
Intervenor expenses	$60,000	1	$12,000
Settlement conference expenses	$10,000	1	$2,000
Customer surveys (every 2 yrs)	$20,000	3	$10,000
safety survey (every 2 yrs)	$10,000	2	$5,000
LRAM consulting services	$5,000	5	$5,000
	$585,000		$130,000

Total costs of $405,760 have been included in expenses in the 2018 test year.

Table 4-39 below, Appendix 2-M is included to detail the change in regulatory costs between the last rebasing and the current Application.

Table 4-39 - Appendix 2-M Regulatory Cost Schedule

Appendix 2-M
Regulatory Cost Schedule

	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost? [2]	Last Rebasing Year (2013 Board Approved)	Most Current Actuals Year 2016	2017 Bridge Year	Annual % Change	2018 Test Year	Annual % Change
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
1	OEB Annual Assessment	5655		On-Going	$ 102,000	$ 152,424	$ 150,000	-1.59%	$ 180,000	20.00%
2	OEB Section 30 Costs (Applicant-originated)									
3	OEB Section 30 Costs (OEB-initiated)	5655		On-Going	$ 5,000	$ 8,019	$ 10,000	24.70%	$ 10,000	0.00%
4	Expert Witness costs for regulatory matters									
5	Legal costs for regulatory matters									
6	Consultants' costs for regulatory matters	5655		On-Going	$ 31,250	$ 48,200	$ 150,800	212.86%	$ 106,816	-29.17%
7	Operating expenses associated with staff resources allocated to regulatory matters	5655		On-Going	$ 132,791	$ 38,096	$ 39,492	3.66%	$ 95,341	141.42%
8	Operating expenses associated with other resources allocated to regulatory matters [1]									
9	Other regulatory agency fees or assessments									
10	Any other costs for regulatory matters (please define)									
11	Intervenor costs	5655		On-Going					$ 14,000	
12	Sub-total - Ongoing Costs [3]	▨	$ -	▨	$ 271,041	$ 246,739	$ 350,292	41.97%	$ 406,157	15.95%
13	Sub-total - One-time Costs [4]	▨	$ -	▨	$ -	$ -	$ -		$ -	
14	Total	▨	$ -	▨	$ 271,041	$ 246,739	$ 350,292	41.97%	$ 406,157	15.95%

2.4.3.6. Low-Income Energy Assistance Programs (“LEAP”)

The delivery of LEAP relies heavily on the cooperation between PUC Distribution and its lead social agency, United Way – Community Assistance Trust, to administer the program within PUC Distribution’s Service Territory.

In accordance with Filing Guidelines 2.4.3.6, PUC Distribution has included $24,000 of expense in test year expenses. PUC Distribution understands that the included figure of $24,000 has been used throughout the application. This is $2,497 less than the calculated amount of $26,497. At the time the final rates are determined, PUC will update this figure as calculated in Table 4-40 – LEAP. In the table below, this amount is based on 0.12% of the 2018 Test Year. This amount has been included in Account 6205 – Donations, to ensure that it is captured appropriately in the Revenue Requirement.

PUC Distribution’s 2018 Test Year Revenue Requirement does not include any legacy low income energy assistance programs.

Table 4-40 – LEAP

	2018 Test Year
Service Revenue Requirement	$ 22,081,244
LEAP %	0.12%
LEAP Amount	$ 26,497
LEAP Amount Used	$ 24,000

2.4.3.7. Charitable and Political Donations

Other than the LEAP charitable donations discussed in Section 2.4.3.6 above, PUC Distribution has not included any other charitable donations in OM&A expenses.

PUC Distribution also confirms it does not make political contributions; therefore no political contributions have nee included for recovery.

2.4.4 Depreciation, Amortization And Depletion

Depreciation Policy

Amortization on capital assets is calculated as follows:

- PUC Distribution uses the pooling of assets for all fixed assets. Amortization is calculated on a straight line basis over the estimated useful life of the assets commencing when the asset is put in service
- In its previous Cost of Service Application (2013) PUC Distribution reviewed the useful life of its assets with the aid of the Asset Depreciation Study by Kinetrics
- There have been no changes to any amortization periods for capital assets since the last Cost of Service Application
- Effective 2017, PUC Distribution's current Amortization policy has been updated to match OEB guidelines with half year amortization on capital additions. Prior to 2017, PUC Distribution's amortization policy has been to take a full year's amortization on

capital additions during the current year. As per OEB guidelines, LDCs are required to use the half-year rule when accounting for amortization expense. Audited Financial Statements for 2013, 2014, 2015 and 2016 include full year amortization on capital additions. For the purposes of regulatory accounting and this rate application, PUC Distribution has applied the half year rule for calculating depreciation expense from 2014 to the 2016.

- For the purposes of calculating depreciation for this Application, the half-year rule has been applied for all 2017 Bridge Year and 2018 Test Year capital additions and capital contributions in accordance with Section 2.4.4 of Chapter 2 of the Board's Filing Requirements.
- Tables 4-42 to 4-47 provide a summary by year for 2013 Actual, 2014 Actual, 2015 Actual, 2016 Actual, 2017 Bridge and 2018 Test Year, respectively, of PUC Distribution's depreciation expense.

In 2012, PUC Distribution modified useful lives as described in the 2013 Cost of Service Application, EB-2012-0162. In 2017, an error in the depreciation that occurred upon conversion to Modified IFRS in 2012 was discovered. For the purpose of this application, PUC Distribution has corrected the error and restated depreciation for 2012 to 2016. Table 4-41 below provides an accumulated depreciation reconciliation for 2013 to 2016 from the audited values to the continuity schedule values.

Table 4-41 – Accumulated Depreciation Reconciliation

	2013	2014	2015	2016
Year End Audit	**52,595,690**	**3,896,379**	**7,976,379**	**12,072,523**
Adjustments:				
Depreciation Changes	(1,317,061)	(516,333)	(1,261,605)	(1,770,615)
Contributed Capital after IFRS conversion		(13,072)	(44,900)	(88,042)
Values as per Continuity	**$ 51,278,629**	**$ 3,366,974**	**$ 6,669,874**	**$ 10,213,866**

Depreciation Changes

Upon conversion to Modified IFRS in 2012, depreciation in OEB accounts 1830, 1835, 1840, 1845 and 1855 were incorrectly calculated. Starting in 2012, the depreciation amount was calculated using the gross asset amount instead of the Net Book Value, therefore inflating depreciation. Since the error is significant, adjustments were made in 2017. The depreciation change in 2014, 2015 and 2016 also includes the adjustment from full year to half year depreciation.

Construction in progress assets are not depreciated until the project is complete. Interest is not typically capitalized to the cost of assets constructed as the life cycle of construction projects are usually less than one year.

The tables beginning with Table 4-42 and ending with Table 4-47 provide a summary by year for 2013 Actual, 2014 Actual, 2015 Actual, 2016 Actual, 2017 Bridge Year and 2018 Test Year of depreciation expense including asset amounts and depreciation rates. These tables reflect the Accumulated Depreciation balances in the Fixed Asset Continuity schedule in Exhibit 2, which are consistent with the Board’s Appendix 2-BA.

Table 4-42– Depreciation 2013

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1706	Land Rights	602,307			602,307	0			0	602,307
N/A	1725	Poles and Fixtures	1,875,300		121,813	1,753,487	204,242	66,718	121,813	149,148	1,604,339
N/A	1730	Conductors	90,074			90,074	19,081	7,099		26,180	63,894
N/A	1735	UG Conduit	1,017,328		31,461	985,866	109,571	37,736	31,461	115,846	870,020
N/A	1740	UG Conductor	244,819			244,819	21,784	7,783		29,567	215,252
N/A	1805	Land	89,160			89,160	0			0	89,160
CEC	1806	Land Rights	153,573	555		154,128	0			0	154,128
47	1808	Buildings and Fixtures	24,138,419	1,861,467		25,999,886	713,261	661,658		1,374,919	24,624,967
13	1810	Leasehold Improvements	0			0	0			0	0
47	1815	Transformer Station Equipment - Normally Primary above 50 kV	8,608,060	448,214		9,056,274	3,353,684	210,868		3,564,552	5,491,722
47	1820	Distribution Station Equipment - Normally Primary below 50 kV	10,648,862	3,832,429		14,481,291	6,428,451	240,222		6,668,673	7,812,618
47	1825	Storage Battery Equipment	19,241			19,241	4,879	640		5,519	13,722
47	1830	Poles, Towers and Fixtures	12,848,549	2,320,239		15,168,788	4,438,928	283,445		4,722,373	10,446,415
47	1835	Overhead Conductors and Devices	13,188,626	763,655		13,952,281	5,437,497	169,054		5,606,551	8,345,730
47	1840	Underground Conduit	10,626,856	226,255		10,853,111	8,228,190	78,890		8,307,080	2,546,031
47	1845	Underground Conductors and Devices	19,762,325	400,996		20,163,321	8,298,720	427,501		8,726,221	11,437,101
47	1850	Line Transformers	16,784,572	675,571	25,049	17,435,095	7,914,410	316,591		8,231,001	9,204,094
47	1855	Services	4,072,588	833,240		4,905,828	351,697	93,542		445,240	4,460,588
47	1860	Meters	10,366,772	271,622	4,298,049	6,340,345	4,280,639	428,593	2,837,860	1,871,372	4,468,973
N/A	1865	Other Installations on Customer's Premises				0	0			0	0
N/A	1905	Land				0	0			0	0
CEC	1906	Land Rights				0	0			0	0
47	1908	Buildings and Fixtures				0	0	0		0	0
13	1910	Leasehold Improvements				0	0			0	0
8	1915	Office Furniture and Equipment				0	0			0	0
10	1920	Computer Equipment - Hardware	20,338			20,338	16,850	2,127		18,977	1,361
12	1925	Computer Software	534,008	1,500		535,508	324,937	104,597		429,534	105,974
10	1930	Transportation Equipment				0	0			0	0
8	1935	Stores Equipment				0	0			0	0
8	1940	Tools, Shop and Garage Equipment				0	0			0	0
8	1945	Measurement and Testing Equipment				0	0			0	0
8	1950	Power Operated Equipment				0	0			0	0
8	1955	Communication Equipment				0	0			0	0
8	1960	Miscellaneous Equipment				0	0			0	0
47	1970	Load Management Controls - Customer Premises	0			0	0			0	0
47	1975	Load Management Controls - Utility Premises				0	0			0	0
47	1980	System Supervisory Equipment	4,193,036	161,782		4,354,818	2,768,287	204,920		2,973,207	1,381,610
47	1985	Sentinel Lighting Rentals				0	0			0	0
47	1990	Other Tangible Property				0	0			0	0
47	1995	Contributions and Grants	(11,772,809)	(1,376,260)		(13,149,068)	(1,670,785)	(316,544)		(1,987,329)	(11,161,739)
	2005	Property under Capital Lease				0				0	0
		Total before Work in Process	**128,112,005**	**10,421,265**	**4,476,372**	**134,056,899**	**51,244,324**	**3,025,441**	**2,991,134**	**51,278,631**	**82,778,268**
WIP		Work in Process				0	0			0	0
	2070	Other Utility Plant - assets not in use				0				0	0
		Total after Work in Process	**128,112,005**	**10,421,265**	**4,476,372**	**134,056,899**	**51,244,324**	**3,025,441**	**2,991,134**	**51,278,631**	**82,778,268**
							Less: Fully Allocated Depreciation				
							Contributed Capital				
							Communication				
							Net Depreciation	3,025,441			

Table 4-43 – Depreciation 2014

			Cost					Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance		Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1706	Land Rights	602,307			602,307		0			0	602,307
N/A	1725	Poles and Fixtures	1,604,339			1,604,339		0	39,130		39,130	1,565,209
N/A	1730	Conductors	63,894			63,894		0	1,997		1,997	61,897
N/A	1735	UG Conduit	870,020			870,020		0	24,858		24,858	845,163
N/A	1740	UG Conductor	215,252			215,252		0	9,784		9,784	205,468
N/A	1805	Land	89,160			89,160		0			0	89,160
CEC	1806	Land Rights	154,128	6,798		160,926		0			0	160,926
47	1808	Buildings and Fixtures	24,624,967	244,854		24,869,821		0	675,297		675,297	24,194,524
13	1810	Leasehold Improvements	0			0		0			0	0
47	1815	Transformer Station Equipment - Normally Prim	5,491,722	617,923		6,109,645		0	236,546		236,546	5,873,099
47	1820	Distribution Station Equipment - Normally Prim	7,812,618	1,245,158		9,057,776		0	370,683		370,683	8,687,092
47	1825	Storage Battery Equipment	13,722			13,722		0	653		653	13,068
47	1830	Poles, Towers and Fixtures	10,446,415	2,281,968		12,728,383		0	262,774		262,774	12,465,609
47	1835	Overhead Conductors and Devices	8,345,730	960,049		9,305,779		0	239,826		239,826	9,065,953
47	1840	Underground Conduit	2,546,031	282,137		2,828,168		0	214,991		214,991	2,613,177
47	1845	Underground Conductors and Devices	11,437,101	582,719		12,019,820		0	504,549		504,549	11,515,270
47	1850	Line Transformers	9,204,094	645,934		9,850,028		0	244,077		244,077	9,605,951
47	1855	Services	4,460,588	541,557		5,002,145		0	130,675		130,675	4,871,471
47	1860	Meters	4,468,973	141,089		4,610,062		0	410,973		410,973	4,199,089
N/A	1865	Other Installations on Customer's Premises	0			0		0			0	0
N/A	1905	Land	0			0		0			0	0
CEC	1906	Land Rights	0			0		0			0	0
47	1908	Buildings and Fixtures	0			0		0			0	0
13	1910	Leasehold Improvements	0			0		0			0	0
8	1915	Office Furniture and Equipment	0			0		0			0	0
10	1920	Computer Equipment - Hardware	1,361			1,361		0	1,361		1,361	(0)
12	1925	Computer Software	105,974			105,974		0	105,974		105,974	(0)
10	1930	Transportation Equipment	0			0		0			0	0
8	1935	Stores Equipment	0			0		0			0	0
8	1940	Tools, Shop and Garage Equipment	0			0		0			0	0
8	1945	Measurement and Testing Equipment	0			0		0			0	0
8	1950	Power Operated Equipment	0			0		0			0	0
8	1955	Communication Equipment	0			0		0			0	0
8	1960	Miscellaneous Equipment	0			0		0			0	0
47	1970	Load Management Controls - Customer Premis	0			0		0			0	0
47	1975	Load Management Controls - Utility Premises	0			0		0			0	0
47	1980	System Supervisory Equipment	1,381,610	156,593		1,538,203		0	234,183		234,183	1,304,020
47	1985	Sentinel Lighting Rentals	0			0		0			0	0
47	1990	Other Tangible Property	0			0		0			0	0
47	1995	Contributions and Grants	(11,161,739)	(1,045,731)		(12,207,470)		0	(341,358)		(341,358)	(11,866,112)
	2005	Property under Capital Lease	0			0		0			0	0
		Total before Work in Process	**82,778,268**	**6,661,048**	**0**	**89,439,316**		**0**	**3,366,973**	**0**	**3,366,973**	**86,072,343**
WIP		Work in Process	0			0		0			0	0
	2070	Other Utility Plant - assets not in use	0			0		0			0	0
		Total after Work in Process	**82,778,268**	**6,661,048**	**0**	**89,439,316**		**0**	**3,366,973**	**0**	**3,366,973**	**86,072,343**

Less: Fully Allocated Depreciation	
Contributed Capital	
Communication	
Net Depreciation	3,366,973

Table 4-44 – Depreciation 2015

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1706	Land Rights	602,307			602,307	0			0	602,307
N/A	1725	Poles and Fixtures	1,604,339			1,604,339	39,130	39,130		78,260	1,526,079
N/A	1730	Conductors	63,894			63,894	1,997	1,997		3,993	59,901
N/A	1735	UG Conduit	870,020			870,020	24,858	24,858		49,715	820,305
N/A	1740	UG Conductor	215,252			215,252	9,784	9,784		19,568	195,684
N/A	1805	Land	89,160			89,160	0			0	89,160
CEC	1806	Land Rights	160,926	5,693		166,619	0			0	166,619
47	1808	Buildings and Fixtures	24,869,821	66,532		24,936,353	675,297	678,518		1,353,815	23,582,538
13	1810	Leasehold Improvements	0			0	0			0	0
47	1815	Transformer Station Equipment - Normally Prima	6,109,645	100,183		6,209,828	236,546	245,522		482,068	5,727,760
47	1820	Distribution Station Equipment - Normally Prima	9,057,776	865,058		9,922,834	370,683	397,061		767,745	9,155,089
47	1825	Storage Battery Equipment	13,722			13,722	653	653		1,307	12,415
47	1830	Poles, Towers and Fixtures	12,728,383	1,854,371		14,582,754	262,774	308,733		571,507	14,011,247
47	1835	Overhead Conductors and Devices	9,305,779	1,150,860		10,456,639	239,826	257,417		497,243	9,959,395
47	1840	Underground Conduit	2,828,168	339,474		3,167,642	214,991	221,207		436,197	2,731,444
47	1845	Underground Conductors and Devices	12,019,820	785,894		12,805,714	504,549	521,657		1,026,206	11,779,507
47	1850	Line Transformers	9,850,028	1,127,232		10,977,260	244,077	266,241		510,318	10,466,942
47	1855	Services	5,002,145	357,901		5,360,046	130,675	141,918		272,593	5,087,454
47	1860	Meters	4,610,062	52,944		4,663,006	410,973	417,441		828,414	3,834,592
N/A	1865	Other Installations on Customer's Premises	0			0	0			0	0
N/A	1905	Land	0			0	0			0	0
CEC	1906	Land Rights	0			0	0			0	0
47	1908	Buildings and Fixtures	0			0	0			0	0
13	1910	Leasehold Improvements	0			0	0			0	0
8	1915	Office Furniture and Equipment	0			0	0			0	0
10	1920	Computer Equipment - Hardware	1,361		1,361	(0)	1,361		1,361	0	(0)
12	1925	Computer Software	105,974		105,974	(0)	105,974		105,974	0	(0)
10	1930	Transportation Equipment	0			0	0			0	0
8	1935	Stores Equipment	0			0	0			0	0
8	1940	Tools, Shop and Garage Equipment	0			0	0			0	0
8	1945	Measurement and Testing Equipment	0			0	0			0	0
8	1950	Power Operated Equipment	0			0	0			0	0
8	1955	Communication Equipment	0			0	0			0	0
8	1960	Miscellaneous Equipment	0			0	0			0	0
47	1970	Load Management Controls - Customer Premise	0			0	0			0	0
47	1975	Load Management Controls - Utility Premises	0			0	0			0	0
47	1980	System Supervisory Equipment	1,538,203	4,551		1,542,754	234,183	238,212		472,395	1,070,360
47	1985	Sentinel Lighting Rentals	0			0	0			0	0
47	1990	Other Tangible Property	0			0	0			0	0
47	1995	Contributions and Grants	(12,207,470)	(454,801)		(12,662,271)	(341,358)	(360,115)		(701,473)	(11,960,798)
	2005	Property under Capital Lease	0			0	0			0	0
		Total before Work in Process	**89,439,316**	**6,255,892**	**107,335**	**95,587,872**	**3,366,973**	**3,410,235**	**107,335**	**6,669,872**	**88,918,000**
WIP		Work in Process	0			0	0			0	0
	2070	Other Utility Plant - assets not in use	0			0					0
		Total after Work in Process	**89,439,316**	**6,255,892**	**107,335**	**95,587,872**	**3,366,973**	**3,410,235**	**107,335**	**6,669,872**	**88,918,000**
							Less: Fully Allocated Depreciation				
							Contributed Capital				
							Communication				
							Net Depreciation	3,410,235			

Table 4-45– Depreciation 2016

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1706	Land Rights	602,307			602,307	0			0	602,307
N/A	1725	Poles and Fixtures	1,604,339			1,604,339	78,260	39,130		117,391	1,486,949
N/A	1730	Conductors	63,894			63,894	3,993	1,997		5,990	57,904
N/A	1735	UG Conduit	870,020			870,020	49,715	24,858		74,573	795,447
N/A	1740	UG Conductor	215,252			215,252	19,568	9,784		29,353	185,900
N/A	1805	Land	89,160			89,160	0			0	89,160
CEC	1806	Land Rights	166,619	7,064		173,683	0			0	173,683
47	1808	Buildings and Fixtures	24,936,353	82,630		25,018,983	1,353,815	680,892		2,034,707	22,984,276
13	1810	Leasehold Improvements	0			0	0			0	0
47	1815	Transformer Station Equipment - Normally Prima	6,209,828	275,737		6,485,565	482,068	250,221		732,289	5,753,276
47	1820	Distribution Station Equipment - Normally Primar	9,922,834	276,939		10,199,773	767,745	411,336		1,179,081	9,020,692
47	1825	Storage Battery Equipment	13,722			13,722	1,307	653		1,960	11,762
47	1830	Poles, Towers and Fixtures	14,582,754	1,601,920		16,184,674	571,507	347,136		918,643	15,266,031
47	1835	Overhead Conductors and Devices	10,456,639	1,278,318		11,734,957	497,243	277,660		774,904	10,960,053
47	1840	Underground Conduit	3,167,642	377,141		3,544,783	436,197	228,373		664,570	2,880,212
47	1845	Underground Conductors and Devices	12,805,714	333,422		13,139,136	1,026,206	535,648		1,561,855	11,577,281
47	1850	Line Transformers	10,977,260	1,279,182		12,256,442	510,318	295,574		805,892	11,450,550
47	1855	Services	5,360,046	349,553		5,709,599	272,593	150,761		423,354	5,286,246
47	1860	Meters	4,663,006	83,653		4,746,659	828,414	421,994		1,250,408	3,496,251
N/A	1865	Other Installations on Customer's Premises	0			0	0			0	0
N/A	1905	Land	0			0	0			0	0
CEC	1906	Land Rights	0			0	0			0	0
47	1908	Buildings and Fixtures	0			0	0			0	0
13	1910	Leasehold Improvements	0			0	0			0	0
8	1915	Office Furniture and Equipment	0			0	0			0	0
10	1920	Computer Equipment - Hardware	(0)			(0)	0			0	(0)
12	1925	Computer Software	(0)			(0)	0			0	(0)
10	1930	Transportation Equipment	0			0	0			0	0
8	1935	Stores Equipment	0			0	0			0	0
8	1940	Tools, Shop and Garage Equipment	0			0	0			0	0
8	1945	Measurement and Testing Equipment	0			0	0			0	0
8	1950	Power Operated Equipment	0			0	0			0	0
8	1955	Communication Equipment	0			0	0			0	0
8	1960	Miscellaneous Equipment	0			0	0			0	0
47	1970	Load Management Controls - Customer Premise	0			0	0			0	0
47	1975	Load Management Controls - Utility Premises	0			0	0			0	0
47	1980	System Supervisory Equipment	1,542,754	43,067		1,585,821	472,395	239,402		711,797	874,024
47	1985	Sentinel Lighting Rentals	0			0	0			0	0
47	1990	Other Tangible Property	0			0	0			0	0
47	1995	Contributions and Grants	(12,662,271)	(450,272)		(13,112,543)	(701,473)	(371,428)		(1,072,901)	(12,039,642)
	2005	Property under Capital Lease	0			0	0			0	0
		Total before Work in Process	**95,587,872**	**5,538,354**	**0**	**101,126,227**	**6,669,872**	**3,543,993**	**0**	**10,213,865**	**90,912,362**
WIP	2055	Work in Process	0			0	0			0	0
	2070	Other Utility Plant	0			0				0	0
		Total after Work in Process	**95,587,872**	**5,538,354**	**0**	**101,126,227**	**6,669,872**	**3,543,993**	**0**	**10,213,865**	**90,912,362**

Note: Opening balances in Cost and Accumulated Depreciation have been adjusted to agree to the opening balances in the General Ledger, which have been adjusted for IFRS purposes.

Less: Fully Allocated Depreciation	
Contributed Capital	
Communication	
Net Depreciation	3,543,993

Table 4-46– Depreciation 2017

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1706	Land Rights	602,307			602,307	0			0	602,307
N/A	1725	Poles and Fixtures	1,604,339			1,604,339	117,391	39,130		156,521	1,447,819
N/A	1730	Conductors	63,894			63,894	5,990	1,997		7,987	55,907
N/A	1735	UG Conduit	870,020			870,020	74,573	24,858		99,431	770,589
N/A	1740	UG Conductor	215,252			215,252	29,353	9,784		39,137	176,115
N/A	1805	Land	89,160			89,160	0			0	89,160
CEC	1806	Land Rights	173,683	2,446		176,129	0			0	176,129
47	1808	Buildings and Fixtures	25,018,983			25,018,983	2,034,707	682,544		2,717,251	22,301,732
13	1810	Leasehold Improvements	0			0	0			0	0
47	1815	Transformer Station Equipment - Normally Prima	6,485,565	442,651		6,928,216	732,289	259,201		991,490	5,936,726
47	1820	Distribution Station Equipment - Normally Prima	10,199,773	636,897		10,836,670	1,179,081	422,759		1,601,840	9,234,830
47	1825	Storage Battery Equipment	13,722			13,722	1,960	653		2,614	11,108
47	1830	Poles, Towers and Fixtures	16,184,674	1,380,875		17,565,549	918,643	380,278		1,298,921	16,266,628
47	1835	Overhead Conductors and Devices	11,734,957	873,437		12,608,394	774,904	295,592		1,070,495	11,537,899
47	1840	Underground Conduit	3,544,783	262,089		3,806,872	664,570	234,765		899,335	2,907,536
47	1845	Underground Conductors and Devices	13,139,136	385,581		13,524,717	1,561,855	544,636		2,106,490	11,418,226
47	1850	Line Transformers	12,256,442	1,050,773		13,307,215	805,892	323,951		1,129,843	12,177,372
47	1855	Services	5,709,599	425,178		6,134,777	423,354	160,445		583,799	5,550,978
47	1860	Meters	4,746,659	213,868		4,960,527	1,250,408	431,912		1,682,320	3,278,207
N/A	1865	Other Installations on Customer's Premises	0			0	0			0	0
N/A	1905	Land	0			0	0			0	0
CEC	1906	Land Rights	0			0	0			0	0
47	1908	Buildings and Fixtures	0			0	0			0	0
13	1910	Leasehold Improvements	0			0	0			0	0
8	1915	Office Furniture and Equipment	0			0	0			0	0
10	1920	Computer Equipment - Hardware	(0)			(0)	0			0	(0)
12	1925	Computer Software	(0)			(0)	0			0	(0)
10	1930	Transportation Equipment	0			0	0			0	0
8	1935	Stores Equipment	0			0	0			0	0
8	1940	Tools, Shop and Garage Equipment	0			0	0			0	0
8	1945	Measurement and Testing Equipment	0			0	0			0	0
8	1950	Power Operated Equipment	0			0	0			0	0
8	1955	Communication Equipment	0			0	0			0	0
8	1960	Miscellaneous Equipment	0			0	0			0	0
47	1970	Load Management Controls - Customer Premise	0			0	0			0	0
47	1975	Load Management Controls - Utility Premises	0			0	0			0	0
47	1980	System Supervisory Equipment	1,585,821	4,186		1,590,007	711,797	240,584		952,381	637,627
47	1985	Sentinel Lighting Rentals	0			0	0			0	0
47	1990	Other Tangible Property	0			0	0			0	0
47	1995	Contributions and Grants	(13,112,543)	(996,060)		(14,108,603)	(1,072,901)	(389,507)		(1,462,408)	(12,646,195)
	2005	Property under Capital Lease	0			0	0			0	0
		Total before Work in Process	**101,126,227**	**4,681,921**	**0**	**105,808,148**	**10,213,865**	**3,663,582**	**0**	**13,877,447**	**91,930,701**
	2070	Other utility plant	0			0					0
WIP	2055	Work in Process	0			0	0			0	0
		Total after Work in Process	**101,126,227**	**4,681,921**	**0**	**105,808,148**	**10,213,865**	**3,663,582**	**0**	**13,877,447**	**91,930,701**

Less: Fully Allocated Depreciation	
Contributed Capital	
Communication	
Net Depreciation	3,663,582

Table 4-47– Depreciation 2018

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1706	Land Rights	602,307			602,307	0			0	602,307
N/A	1725	Poles and Fixtures	1,604,339			1,604,339	156,521	39,130		195,651	1,408,688
N/A	1730	Conductors	63,894			63,894	7,987	1,997		9,983	53,911
N/A	1735	UG Conduit	870,020			870,020	99,431	24,858		124,289	745,732
N/A	1740	UG Conductor	215,252			215,252	39,137	9,784		48,921	166,331
N/A	1805	Land	89,160			89,160	0			0	89,160
CEC	1806	Land Rights	176,129	1,621		177,750	0			0	177,750
47	1808	Buildings and Fixtures	25,018,983	63,099		25,082,082	2,717,251	683,596		3,400,847	21,681,235
13	1810	Leasehold Improvements	0			0	0			0	0
47	1815	Transformer Station Equipment - Normally Prima	6,928,216	122,779		7,050,995	991,490	266,269		1,257,759	5,793,236
47	1820	Distribution Station Equipment - Normally Prima	10,836,670	526,035		11,362,705	1,601,840	437,296		2,039,136	9,323,569
47	1825	Storage Battery Equipment	13,722			13,722	2,614	653		3,267	10,455
47	1830	Poles, Towers and Fixtures	17,565,549	1,586,992		19,152,541	1,298,921	413,255		1,712,176	17,440,365
47	1835	Overhead Conductors and Devices	12,608,394	1,034,718		13,643,112	1,070,495	311,493		1,381,988	12,261,124
47	1840	Underground Conduit	3,806,872	214,630		4,021,502	899,335	239,532		1,138,868	2,882,634
47	1845	Underground Conductors and Devices	13,524,717	352,285		13,877,002	2,106,490	553,859		2,660,350	11,216,652
47	1850	Line Transformers	13,307,215	1,272,911		14,580,126	1,129,843	352,997		1,482,841	13,097,285
47	1855	Services	6,134,777	457,483		6,592,260	583,799	171,479		755,277	5,836,983
47	1860	Meters	4,960,527	146,036		5,106,563	1,682,320	443,908		2,126,228	2,980,335
N/A	1865	Other Installations on Customer's Premises	0			0	0			0	0
N/A	1905	Land	0			0	0			0	0
CEC	1906	Land Rights	0			0	0			0	0
47	1908	Buildings and Fixtures	0			0	0			0	0
13	1910	Leasehold Improvements	0			0	0			0	0
8	1915	Office Furniture and Equipment	0			0	0			0	0
10	1920	Computer Equipment - Hardware	(0)			(0)	0			0	(0)
12	1925	Computer Software	(0)			(0)	0			0	(0)
10	1930	Transportation Equipment	0			0	0			0	0
8	1935	Stores Equipment	0			0	0			0	0
8	1940	Tools, Shop and Garage Equipment	0			0	0			0	0
8	1945	Measurement and Testing Equipment	0			0	0			0	0
8	1950	Power Operated Equipment	0			0	0			0	0
8	1955	Communication Equipment	0			0	0			0	0
8	1960	Miscellaneous Equipment	0			0	0			0	0
47	1970	Load Management Controls - Customer Premise	0			0	0			0	0
47	1975	Load Management Controls - Utility Premises	0			0	0			0	0
47	1980	System Supervisory Equipment	1,590,007	29,766		1,619,773	952,381	241,432		1,193,813	425,960
47	1985	Sentinel Lighting Rentals	0			0	0			0	0
47	1990	Other Tangible Property	0			0	0			0	0
47	1995	Contributions and Grants	(14,108,603)	(450,000)		(14,558,603)	(1,462,408)	(407,583)		(1,869,991)	(12,688,612)
	2005	Property under Capital Lease	0			0	0			0	0
		Total before Work in Process	**105,808,148**	**5,358,355**	**0**	**111,166,503**	**13,877,447**	**3,783,956**	**0**	**17,661,403**	**93,505,100**
	2070	Other utility plant	0			0					0
WIP	2055	Work in Process	0			0	0			0	0
		Total after Work in Process	**105,808,148**	**5,358,355**	**0**	**111,166,503**	**13,877,447**	**3,783,956**	**0**	**17,661,403**	**93,505,100**
							Less: Fully Allocated Depreciation				
			108,487,325				Contributed Capital				
							Communication				
							Net Depreciation	3,783,956			

Table 4-48– Depreciation and Amortization Variance Summary

OEB	Description	2013	2014	2015	2016	2017	2018
1706	Land Rights						
1725	Poles and Fixtures	(4,404)	(27,588)	0	0	0	0
1730	Conductors	(469)	(5,102)	0	0	0	0
1735	UG Conduit	(1,043)	(12,878)	0	0	0	0
1740	UG Conductor	(215)	2,001	0	0	0	0
1805	Land						
1806	Land Rights						
1808	Buildings and Fixtures	622,819	13,639	3,222	2,373	1,653	1,052
1810	Leasehold Improvements						
1815	Transformer Station Equipment - Normally Primary above 50 kV	6,541	25,678	8,976	4,699	8,980	7,068
1820	Distribution Station Equipment - Normally Primary below 50 kV	95,811	130,461	26,378	14,275	11,423	14,537
1825	Storage Battery Equipment	(0)	13	0	0	0	0
1830	Poles, Towers and Fixtures	51,509	(20,672)	45,959	38,403	33,142	32,976
1835	Overhead Conductors and Devices	12,753	70,772	17,591	20,243	17,931	15,901
1840	Underground Conduit	4,525	136,101	6,216	7,166	6,392	4,767
1845	Underground Conductors and Devices	25,584	77,048	17,108	13,991	8,988	9,223
1850	Line Transformers	16,263	(72,514)	22,165	29,333	28,377	29,046
1855	Services	5,272	37,132	11,243	8,843	9,684	11,033
1860	Meters	(1,159,752)	(17,620)	6,468	4,553	9,917	11,997
1865	Other Installations on Customer's Premises						
1905	Land						
1906	Land Rights						
1908	Buildings and Fixtures						
1910	Leasehold Improvements						
1915	Office Furniture and Equipment						
1920	Computer Equipment - Hardware	(5,408)	(766)	(1,361)	0	0	0
1925	Computer Software	(207,840)	1,377	(105,974)	0	0	0
1930	Transportation Equipment						
1935	Stores Equipment						
1940	Tools, Shop and Garage Equipment						
1945	Measurement and Testing Equipment						
1950	Power Operated Equipment						
1955	Communication Equipment						
1960	Miscellaneous Equipment						
1970	Load Management Controls - Customer Premises						
1975	Load Management Controls - Utility Premises						
1980	System Supervisory Equipment	8,089	29,263	4,029	1,190	1,181	849
1985	Sentinel Lighting Rentals						
1990	Other Tangible Property						
1995	Contributions and Grants	(34,407)	(24,814)	(18,757)	(11,313)	(18,079)	(18,076)
	Total	**(564,372)**	**341,532**	**43,262**	**133,758**	**119,590**	**120,373**

Overall the net depreciation difference on an account by account basis was below the materiality threshold.

2013 Account 1808 Buildings – increase in annual depreciation of $622,819 – new integrated office and service centre building in service for a full year

2013 Account 1860 Meters – decrease in annual depreciation of $1,159,752 – approved one time regulatory entry for smart meters occurred in 2012

2013 Account 1925 Computer Software – decrease in annual depreciation of $207,840 – approved one time regulatory entry for computer software associated with smart meters occurred in 2012

Asset Retirement Obligations ("AROs")

PUC Distribution has not recorded any Asset Retirement Obligations in fixed assets.

A detailed list of the asset service lives using Kinetrics study has been provided in Table 4-49 Appendix 2-BB.

Table 4-49 - Appendix 2-BB Service Life Comparison

Appendix 2-BB
Service Life Comparison
Table F-1 from Kinetics Report[1]

		Asset Details			Useful Life			USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
Parent*	#	Category| Component | Type			MIN UL	TUL	MAX UL			Years	Rate	Years	Rate	Below Min TUL	Above Max TUL
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	1830	Poles, Towers and Fixtures	45	2%	45	2%	No	No
			Overall		35	45	75	1725	Poles, Towers and Fixtures	45		45			
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	2	Fully Dressed Concrete Poles	Overall		50	60	80								
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	3	Fully Dressed Steel Poles	Overall		60	60	80								
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	4	OH Line Switch			30	45	55								
	4	OH Line Switch			30	45	55								
	5	OH Line Switch Motor			15	25	25								
	6	OH Line Switch RTU			15	20	20								
	7	OH Integral Switches			35	45	60								
	7	OH Integral Switches			35	45	60								
	8	OH Conductors			50	60	75	1835	Overhead Conductors and Devices	60	2%	60	2%	No	No
	8	OH Conductors			50	60	75	1730	Overhead Conductors and Devices	45		45			
	9	OH Transformers & Voltage Regulators			30	40	60	1850	Line Transformers	40	3%	40	3%	No	No
	10	OH Shunt Capacitor Banks			25	30	40								
	11	Reclosers			25	40	55								
	11	Reclosers			25	40	55	1730	Overhead Conductors and Devices	45	2%	45	2%	No	No
TS & MS	12	Power Transformers	Overall		30	45	60	1820	Distribution Station Equipment<50kV	40	3%	40	3%	No	No
			Bushing		10	20	30								
			Tap Changer		20	30	60								
	13	Station Service Transformer			30	45	55	1820	Distribution Station Equipment<50kV	40	3%	40	3%	No	No
	14	Station Grounding Transformer			30	40	40								
	15	Station DC System	Overall		10	20	30								
			Battery Bank		10	15	15								
			Charger		20	20	30								
	16	Station Metal Clad Switchgear	Overall		30	40	60	1820	Distribution Station Equipment<50kV	40	3%	40	3%	No	No
			Removable Breaker		25	40	60								
	17	Station Independent Breakers			35	45	65	1820	Distribution Station Equipment<50kV	40	3%	40	3%	No	No
	18	Station Switch			30	50	60	1820	Distribution Station Equipment<50kV	40	3%	40	3%	No	No
	19	Electromechanical Relays			25	35	50								
	20	Solid State Relays			10	30	45								
	21	Digital & Numeric Relays			15	20	20								
	22	Rigid Busbars			30	55	60								
	23	Steel Structure			35	50	90								
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables			60	65	75								
	25	Primary Ethylene-Propylene Rubber (EPR) Cables			20	25	25								
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried			20	25	30								
	27	Primary Non-TR XLPE Cables in Duct			20	25	30								
	27	Primary Non-TR XLPE Cables in Duct			20	25	30	1740	Underground Conductors and Devices	25	4%	25	4%	No	No
	30	Secondary PILC Cables			70	75	80								
	30	Secondary PILC Cables			70	75	80								
	31	Secondary Cables Direct Buried			25	35	40	1845	Underground Conductors and Devices	40	3%	40	3%	No	No
	31	Secondary Cables Direct Buried			25	35	40	1740	Underground Conductors and Devices	25	4%	25	4%	No	No
	32	Secondary Cables in Duct			35	40	60	1845	Underground Conductors and Devices	40	3%	40	3%	No	No
	32	Secondary Cables in Duct			35	40	60								
	33	Network Tranformers	Overall		20	35	50								
			Protector		20	35	40								
	34	Pad-Mounted Transformers			25	40	45	1850	Line Transformers	40	3%	40	3%	No	No
	35	Submersible/Vault Transformers			25	35	45								
	36	UG Foundation			35	55	70	1840	Underground Conduit	50	2%	50	2%	No	No
	36	UG Foundation			35	55	70	1735	Underground Conduit	40	3%	40	3%	No	No
	37	UG Vaults	Overall		40	60	80								
			Roof		20	30	45								
	38	UG Vault Switches			20	35	50								
	39	Pad-Mounted Switchgear			20	30	45	1845	Underground Conductors and Devices	40	3%	40	3%	No	No
	39	Pad-Mounted Switchgear			20	30	45	1740	Underground Conductors and Devices	25	4%	25	4%	No	No
	40	Ducts			30	50	85	1840	Underground Conduit	50	2%	50	2%	No	No
	40	Ducts			30	50	85	1735	Underground Conduit	40	3%	40	3%	No	No
	41	Concrete Encased Duct Banks			35	55	80								
	42	Cable Chambers			50	60	80								
S	43	Remote SCADA			15	20	30	1980	System Supervisory Equipment	20	5%	20	5%	No	No

Table F-2 from Kinetics Report[1]

	Asset Details		Useful Life Range		USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
#	Category| Component | Type						Years	Rate	Years	Rate	Below Min Range	Above Max Range
1	Office Equipment		5	15								
2	Vehicles	Trucks & Buckets	5	15								
		Trailers	5	20								
		Vans	5	10								
3	Administrative Buildings		50	75	1808	Buildings and Fixtures	50	2%	50	2%	No	No
4	Leasehold Improvements		Lease dependent									
5	Station Buildings	Station Buildings	50	75								
		Parking	25	30								
		Fence	25	60								
		Roof	20	30								
6	Computer Equipment	Hardware	3	5	1920	Computer Equipment-Hardware	5	20%	5	20%	No	No
		Software	2	5	1925	Computer Software	5	20%	5	20%	No	No
7	Equipment	Power Operated	5	10								
		Stores	5	10								
		Tools, Shop, Garage Equipment	5	10								
		Measurement & Testing Equipment	5	10								
8	Communication	Towers	60	70								
		Wireless	2	10								
9	Residential Energy Meters		25	35								
10	Industrial/Commercial Energy Meters		25	35								
11	Wholesale Energy Meters		15	30	1860	Meters	15	7%	15	7%	No	No
12	Current & Potential Transformer (CT & PT)		35	50								
13	Smart Meters		5	15	1860	Meters	15	7%	15	7%	No	No
14	Repeaters - Smart Metering		10	15	1860	Meters	15	7%	15	7%	No	No
15	Data Collectors - Smart Metering		15	20	1860	Meters	15	7%	15	7%	No	No

2.4.5 Taxes Or Payments In Lieu Of Taxes (Pils) And Property Taxes

PUC Distribution is subject to Payment in Lieu ("PILS") under Section 93 of the *Electricity Act, 1998*, as amended. PUC Distribution does not pay Section 89 proxy taxes, and is exempt from the payment of income and capital taxes under the *Income Tax Act* (Canada) and the *Ontario Corporations Tax Act*. A copy of the 2016 Federal T2 and Ontario C23 tax return has been provide in Appendix 8 to this Exhibit.

PUC Distribution confirms that the financial statements filed with its 2016 corporate income tax returns are the same as the 2016 audited financial statements filed with this application.

In accordance with the filing instructions, PUC Distribution has completed the Board's PILS Work Form and has filed this model in live excel format.

PILS for the 2018 Test Year

The 2018 Test Year's PILS have been calculated at $269,325. The details of the calculations are in the Income Tax/ PILS Work Form in Appendix 10.

The 2018 Test Year PILS have been determined by applying substantively enacted 2018 tax rates against Taxable Income. The 2018 Taxable Income amount has been determined by taking Utility Income before Taxes and applying Schedule 1 corporate tax adjustments to this number.

Utility Income Before Taxes

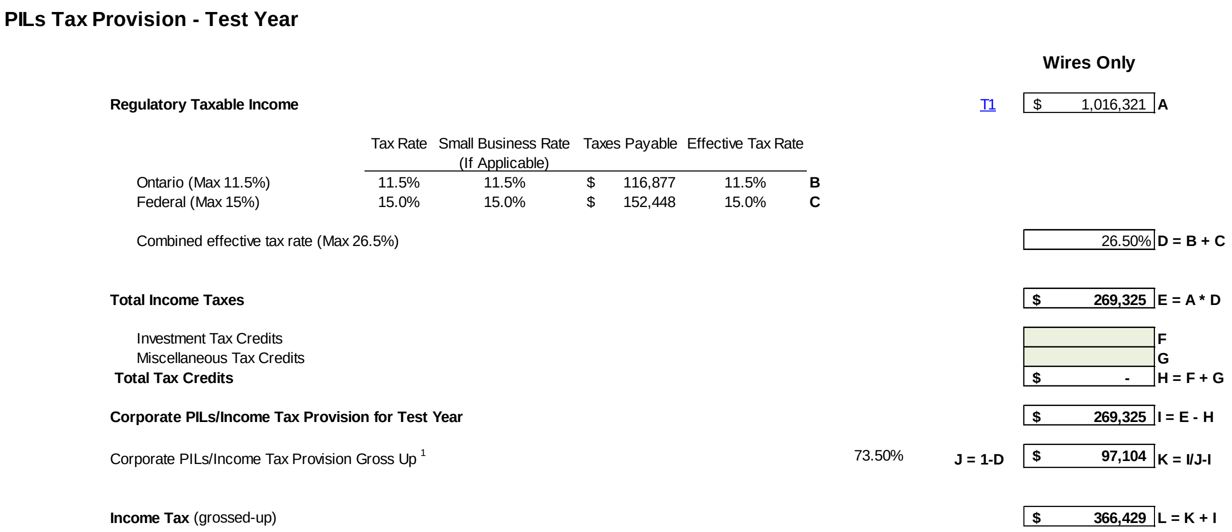
This is calculated based on the 2018 expected total revenues less the 2018 expected cost and expenses. The Utility income before taxes in 2018 is $3,585,733. The details of this calculation can be found in Exhibit 6, Table 6-1.

Tax Adjustments

Tax adjustments are made for both temporary and permanent differences and reserves. Significant temporary differences included are the differences between depreciation for accounting purposes versus capital cost allowance (CCA) for tax purposes.

The tax provision for the 2018 Test Year is detailed in Table 4-50 below as follows:

Table 4-50: PILS Tax Provision 2018 Test Year



PILs Tax Provision - Test Year

	Tax Rate	Small Business Rate (If Applicable)	Taxes Payable	Effective Tax Rate				Wires Only	
Regulatory Taxable Income							T1	$ 1,016,321	A
Ontario (Max 11.5%)	11.5%	11.5%	$ 116,877	11.5%	B				
Federal (Max 15%)	15.0%	15.0%	$ 152,448	15.0%	C				
Combined effective tax rate (Max 26.5%)								26.50%	D = B + C
Total Income Taxes								**$ 269,325**	E = A * D
Investment Tax Credits									F
Miscellaneous Tax Credits									G
Total Tax Credits								**$ -**	H = F + G
Corporate PILs/Income Tax Provision for Test Year								**$ 269,325**	I = E - H
Corporate PILs/Income Tax Provision Gross Up ^{1}						73.50%	J = 1-D	**$ 97,104**	K = I/J-I
Income Tax (grossed-up)								**$ 366,429**	L = K + I

Expected 2018 Tax Rates

PUC Distribution used a combined income tax rate of 26.5% for the 2018 Test Year.

Tax Calculation

The following Table 4-51 presents the tax calculation for the 2018 Test Year.

Table 4-51: Tax Calculation 2018 Test Year

Taxable Income - Test Year

	T2 S1 line #	Working Paper Reference	Test Year Taxable Income
Net Income Before Taxes		A.	3,585,733
Additions:			
Interest and penalties on taxes	103		
Amortization of tangible assets 2-4 ADJUSTED ACCOUNTING DATA P489	104		3,783,956
Amortization of intangible assets 2-4 ADJUSTED ACCOUNTING DATA P490	106		
Recapture of capital cost allowance from Schedule 8	107		
Gain on sale of eligible capital property from Schedule 10	108		
Income or loss for tax purposes- joint ventures or partnerships	109		
Loss in equity of subsidiaries and affiliates	110		
Loss on disposal of assets	111		
Charitable donations	112		
Non-deductible meals and entertainment expense	121		
Total Additions			**3,783,956**
Deductions:			
Capital cost allowance from Schedule 8	403	T8	5,716,913
Total Deductions		calculated	**5,716,913**
NET INCOME FOR TAX PURPOSES		calculated	**1,652,776**
Charitable donations	311		
Taxable dividends received under section 112 or 113	320		
Non-capital losses of preceding taxation years from Schedule 7-1	331	T4	636,455
Net-capital losses of preceding taxation years (Please show calculation)	332	T4	0
Limited partnership losses of preceding taxation years from Schedule 4	335		
REGULATORY TAXABLE INCOME		calculated	**1,016,321**

Tax Calculations and PILs

Capital Cost Allowance

Details of the Capital Cost Allowance continuity schedules for the 2017 Bridge Year and the 2018 Test Year are provided in Tables 4-52 and 4-53 below as follows:

Table 4-52 – CCA Continuity Schedule 2017

Class Description	Working Paper Reference	UCC Regulated Historical Year	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Bridge Year CCA		UCC End of Bridge Year
Distribution System - post 1987	H8	$ 44,009,981.00			$ 44,009,981	$ -	$ 44,009,981	4%	$ 1,760,399		$ 42,249,582
Non-residential Buildings Reg. 1100(1)(a.1) election	H8	$ 140,815.00			$ 140,815	$ -	$ 140,815	6%	$ 8,449		$ 132,366
Distribution System - pre 1988	H8				$ -	$ -	$ -	6%	$ -		$ -
General Office/Stores Equip	H8	$ 1,818,822.00			$ 1,818,822	$ -	$ 1,818,822	20%	$ 363,764		$ 1,455,058
Computer Hardware/ Vehicles	H8				$ -	$ -	$ -	30%	$ -		$ -
Certain Automobiles	H8				$ -	$ -	$ -	30%	$ -		$ -
Computer Software	H8				$ -	$ -	$ -	100%	$ -		$ -
Lease # 1	H8				$ -	$ -	$ -		$ -		$ -
Lease #2	H8				$ -	$ -	$ -		$ -		$ -
Lease # 3	H8				$ -	$ -	$ -		$ -		$ -
Lease # 4	H8				$ -	$ -	$ -		$ -		$ -
Franchise	H8				$ -	$ -	$ -		$ -		$ -
New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	H8				$ -	$ -	$ -	8%	$ -		$ -
Fibre Optic Cable	H8				$ -	$ -	$ -	12%	$ -		$ -
Certain Energy-Efficient Electrical Generating Equipment	H8				$ -	$ -	$ -	30%	$ -		$ -
Certain Clean Energy Generation Equipment	H8				$ -	$ -	$ -	50%	$ -		$ -
Computers & Systems Software acq'd post Mar 22/04	H8				$ -	$ -	$ -	45%	$ -		$ -
Data Network Infrastructure Equipment (acq'd post Mar 22/04)	H8				$ -	$ -	$ -	30%	$ -		$ -
Distribution System - post February 2005	H8	$ 40,643,530.00	$ 4,679,475		$ 45,323,005	$ 2,339,738	$ 42,983,268	8%	$ 3,438,661		$ 41,884,344
Data Network Infrastructure Equipment - post Mar 2007	H8				$ -	$ -	$ -	55%	$ -		$ -
Computer Hardware and system software	H8				$ -	$ -	$ -	100%	$ -		$ -
CWIP	H8				$ -	$ -	$ -	0%	$ -		$ -
Eligible Capital Property (acq'd pre Jan 1, 2017)[1]	H10	$ 2,503,211.25			$ 2,503,211	$ -	$ 2,503,211	7%	$ 175,225		$ 2,327,986
Eligible Capital Property (acq'd post Jan 1, 2017)[1]		$ -			$ -	$ -	$ -	5%	$ -		$ -
					$ -	$ -	$ -		$ -		$ -
					$ -	$ -	$ -		$ -		$ -
					$ -	$ -	$ -		$ -		$ -
					$ -	$ -	$ -		$ -		$ -
					$ -	$ -	$ -		$ -		$ -
					$ -	$ -	$ -		$ -		$ -
					$ -	$ -	$ -		$ -		$ -
					$ -	$ -	$ -		$ -		$ -
TOTAL		$ 89,116,359	$ 4,679,475	$ -	$ 93,795,834	$ 2,339,738	$ 91,456,097		$ 5,746,499	B1	$ 88,049,336

Table 4-53 – CCA Continuity Schedule 2018

Class	Class Description	Working Paper Reference	UCC Test Year Opening Balance	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA		UCC End of Test Year
1	Distribution System - post 1987	B8	$ 42,249,582			$ 42,249,582	$ -	$ 42,249,582	4%	$ 1,689,983		$ 40,559,598
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	B8	$ 132,366			$ 132,366	$ -	$ 132,366	6%	$ 7,942		$ 124,424
2	Distribution System - pre 1988	B8	$ -			$ -	$ -	$ -	6%	$ -		$ -
8	General Office/Stores Equip	B8	$ 1,455,058			$ 1,455,058	$ -	$ 1,455,058	20%	$ 291,012		$ 1,164,046
10	Computer Hardware/ Vehicles	B8	$ -			$ -	$ -	$ -	30%	$ -		$ -
10.1	Certain Automobiles	B8	$ -			$ -	$ -	$ -	30%	$ -		$ -
12	Computer Software	B8	$ -			$ -	$ -	$ -	100%	$ -		$ -
13 1	Lease # 1	B8	$ -			$ -	$ -	$ -		$ -		$ -
13 2	Lease #2	B8	$ -			$ -	$ -	$ -		$ -		$ -
13 3	Lease # 3	B8	$ -			$ -	$ -	$ -		$ -		$ -
13 4	Lease # 4	B8	$ -			$ -	$ -	$ -		$ -		$ -
14	Franchise	B8	$ -			$ -	$ -	$ -		$ -		$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than	B8	$ -			$ -	$ -	$ -	8%	$ -		$ -
42	Fibre Optic Cable	B8	$ -			$ -	$ -	$ -	12%	$ -		$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment	B8	$ -			$ -	$ -	$ -	30%	$ -		$ -
43.2	Certain Clean Energy Generation Equipment	B8	$ -			$ -	$ -	$ -	50%	$ -		$ -
45	Computers & Systems Software acq'd post Mar 22/04	B8	$ -			$ -	$ -	$ -	45%	$ -		$ -
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	B8	$ -			$ -	$ -	$ -	30%	$ -		$ -
47	Distribution System - post February 2005	B8	$ 41,884,344	5,356,734		$ 47,241,078	$ 2,678,367	$ 44,562,711	8%	$ 3,565,017		$ 43,676,061
50	Data Network Infrastructure Equipment - post Mar 2007	B8	$ -			$ -	$ -	$ -	55%	$ -		$ -
52	Computer Hardware and system software	B8	$ -			$ -	$ -	$ -	100%	$ -		$ -
95	CWIP	B8	$ -			$ -	$ -	$ -	0%	$ -		$ -
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)1	B8	$ 2,327,986			$ 2,327,986	$ -	$ 2,327,986	7%	$ 162,959		$ 2,165,027
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)1	B8	$ -			$ -	$ -	$ -	5%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
	TOTAL		$ 88,049,336	$ 5,356,734	$ -	$ 93,406,070	$ 2,678,367	$ 90,727,703		$ 5,716,913	T1	$ 87,689,157

A reconciliation between PUC Distribution’s December 31, 2016 Undepreciatd Capital Cost (“UCC”) balance per the filed tax return and the balance used for the opening UCC balance for the 2017 Bridge Year is provided in Table 4-54 below as follows:

Tabl4-54: Reconciliation of the 2016 UCC Balance

Description	Class Number	December 31, 2016 UCC Balance per S(8)	Opening UCC Balance for 2017 Bridge Year
Distribution System - 1988-Feb 22, 2005	1	$ 23,100,100	$ 44,009,981
New Building	1	$ 20,909,881	$ -
New Building Additions	1b	$ 140,815	$ 140,815
Smart Meters	8	$ 1,818,822	$ 1,818,822
Distribution System - post Feb 22, 2005	47	$ 40,643,530	$ 40,643,530
Total		**$ 86,613,148**	**$ 86,613,148**

Loss Carry Forwards

At the end of 2017, PUC Distribution had projected a loss carry forward of $3,182,275. As noted above in Table 4-55: Tax Calculation 2018 Test Year, PUC Distribution has amortized the $3,182,275 over 5 years beginning in 2018 deducting $636,455 from the 2018 Net Income for Tax Purposes.

Table 4-55 – Corporate Tax Rates

Corporate Tax Rates

Corporate Tax Rates for Tax Year:	2017 Bridge	2018 Test
Federal Income Tax	11.50%	11.50%
Ontario Income Tax	15.00%	15.00%
Combined Income Tax	26.50%	26.50%

Calculation of Tax Credits

PUC Distribution did not include any tax credits, other additions or other deductions in its 2018 Test Year.

Integrity Checks

PUC Distribution confirms the following in Table 4-56: Integrity Checks below:

Table 4-56: Integrity Checks

	Item	Utility Confirmation (Y/N)
1	The depreciation and amortization added back in the application's PILs model agree with the numbers disclosed in the rate base section of the application	Y
2	The capital additions and deductions in the UCC/ CCA Schedule 8 agree with the rate base section for historical, bridge and test years	Y
3	Schedule 8 of the most recent federal T2 tax return filed with the application has a closing December 31 historical year UCC that agrees with the opening (January 1) bridge year UCC. If the amounts do not agree, then the applicant must provide a reconciliation with explanations. Distributors must segregate non- distribution tax amounts on Schedule 8.	Y
4	The CCA deductions in the application's PILs tax model for historical, bridge and test years (as applicable) agree with the numbers in the UCC schedules for the same years filed in the application	Y
5	Loss carry-forwards, if any, from the tax returns (Schedule 4) agree with those disclosed in the application	Y
6	A discussion is included in the application as to when the loss carry-forwards, if any, will be fully utilized	Y
7	CCA is maximized even if there are tax loss carry-forwards	Y
8	Accounting OPEB and pension amounts added back on Schedule 1 to reconcile accounting income to net income for tax purposes, must agree with the OM&A analysis for compensation. The amounts deducted must be reasonable when compared with the notes in the audited financial statements, FSCO reports, and the actuarial valuations.	N/A
9	The income tax rate used to calculate the tax expense must be consistent with the utility's actual tax facts and evidence filed in the application.	Y

Property Taxes

PUC Distribution pays property taxes to the Corporation of the City of Sault Ste. Marie (the City). In addition, PUC Distribution makes annual payments to Ontario Electricity Financial Corporation ("OEFC") for Payment in Lieu of Property Taxes. Property taxes are billed by the City and calculated using MPAC property values and tax assessment rates. PUC Distribution has been including property taxes paid to the City of Sault Ste. Marie in operating accounts 4815, 5012 and 5675. Commencing in 2017, PUC Distribution will be recording the expenses previously charged to account 5675 – Maintenance of General Plant into account 6105 – Taxes Other Than Income Taxes. Table 4-53 – Total Taxes, Other than Income Table 4-57 below shows the continuity of total property taxes for all years up to and including the Test Year

Table 4-57 – Total Taxes, Other than Income

	2013	2014	2015	2016	2017	2018
Total Property Taxes	$404,463	$382,868	$391,708	$391,755	$385,742	$397,617

2.4.5.1. Non-Recoverable and Disallowed Expenses

PUC Distribution does not have any expenses that are deducted for general tax purposes but for which recovery in 2018 distribution rates would be disallowed.

2.4.6 Conservation and Demand Management ("CDM") Costs

2.4.6.1. Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA")

Background

In 2008, the Ontario Energy Board released its *Guidelines for Electricity Distributor Conservation and Demand Management* (EB-2008-0037) that included a provision for distributors to recover revenues lost as a result of Conservation and Demand Management (CDM) initiatives through a "Lost Revenue Adjustment Mechanism" or LRAM. The Guidelines described how the LRAM would be calculated, tracking in accounting systems and disposed of.

On March 31, 2010 the Minister of Energy and Infrastructure issued a Directive to the Ontario Energy Board setting out a framework for conservation and demand management (CDM) initiatives in the 2011 to 2014 period. As part of that Directive, the Minister instructed that "the Board should have regard to the objective that lost revenues that result from CDM programs should not act as a disincentive to a distributor."

To address this and other requirements of the Minister's directive, the OEB released updated *Guidelines for Electricity Distributor Conservation and Demand Management* (EB-2012-003; 26 April 2012) that set out rules for a Lost Revenue Adjustment Mechanism Variance

Account (LRAMVA) that took into account CDM initiatives that were captured in the load forecast and rates.

The OEB established Account 1568 as the LRAMVA to capture the difference between the OEB-approved CDM forecast and actual results at the customer rate class level.

On May 19, 2016, the OEB issued the Report of the OEB: Updated Policy for the Lost Revenue Adjustment Mechanism Calculation: Lost Revenues and Peak Demand Savings from Conservation and Demand Management Programs (the LRAMVA Report). The OEB updated its policy on how peak demand savings from energy efficiency and demand response programs should be treated for LRAMVA purposes.

CDM in the PUC load forecast

PUC Distribution made an estimate of CDM savings and built this into its load forecast as part of its 2013 cost of service rate application, and prepared a table showing the "LRAMVA Threshold", against which lost revenues from CDM should be prepared. That table was part of the Settlement Agreement, which is appended to the Board decision (EB-2012-0162, Table 7 and p. 20 of the Settlement Agreement). The LRAMVA Threshold is based on estimated CDM savings in 2011, 2012 and 2013.

PUC CDM initiatives

PUC Distribution contracted with the Ontario Power Authority (OPA, which has now been merged into the Independent Electricity System Operator – IESO) to offer a suite of CDM programs to customers in a variety of rate classes for the 2011-2014 period and subsequently with the IESO for the 2015-2020 period. The final 2016 annual verified results report is the most recent final CDM evaluation report available from the IESO. That report shows energy savings, peak demand reductions and persistence of these for 2015 and 2016 programs. The spreadsheet has been uploaded to the RESS portal as:

- “Final-Verified-2016-Annual-LDC-CDM-Program-Results-Resport-PUC-Distribution-Inc-20170630.xlsx”

IESO had previously provided a similar report on PUC Distribution’s program initiatives for 2011 through 2014, as well as separate reports showing persistence of these savings for 2011-2013 and for 2014. All three spreadsheets have been uploaded to the RESS portal as follows:

- “2011-2014 Final Results Report_HCPUC Distribution Inc..xlsx”
- “PUC Persistence 2011-2013.xlsx”
- “PUC 2014 Persistence June 15-2006.xlsx”

PUC Distribution relied primarily on these reports for determining the verified savings. These reports are based on the most recent input assumptions available at the time of the evaluation. The exception where these reports do not provide an adequate basis for calculating lost revenues is for PUC Distribution’s street lighting project. Street lights are billed by kW, but savings for street lighting do not affect peak demand, which is what is reported by the IESO. For this project, PUC Distribution relied on actual changes in billing attributable to the program. Net to gross factors for those specific projects were taken from the IESO verified results. Calculations of this are shown on Tab 8 of the OEB LRAMVA work form which has been uploaded to the RESS Portal:

- “PUC 2016 OEB LRAM Workform.xlsb”

Calculation of LRAMVA

PUC Distribution disposed of lost revenues from 2011–2012 CDM programs in 2011–2012 in PUC Distribution’s 2013 and 2014 rate cases. The LRAMVA Threshold estimated from 2011–2013 CDM programs in 2013 is compared to the calculated lost revenue from verified final CDM results. The difference between these two is the LRAMVA value PUC Distribution is claiming for 2013 – 2016. Disposition is being requested for the following revenue losses:

- Lost revenues in 2013 related to programs offered in 2011,
- Lost revenues in 2013 related to programs offered in 2012,
- Lost revenues in 2013 related to programs offered in 2013,
- Lost revenues in 2014 related to programs offered in 2011,
- Lost revenues in 2014 related to programs offered in 2012,
- Lost revenues in 2014 related to programs offered in 2013,
- Lost revenues in 2014 related to programs offered in 2014.
- Lost revenues in 2015 related to programs offered in 2011,
- Lost revenues in 2015 related to programs offered in 2012,
- Lost revenues in 2015 related to programs offered in 2013,
- Lost revenues in 2015 related to programs offered in 2014,
- Lost revenues in 2015 related to programs offered in 2015,
- Lost revenues in 2016 related to programs offered in 2011,
- Lost revenues in 2016 related to programs offered in 2012,
- Lost revenues in 2016 related to programs offered in 2013,
- Lost revenues in 2016 related to programs offered in 2014,
- Lost revenues in 2016 related to programs offered in 2015, and
- Lost revenues in 2016 related to programs offered in 2016.

Details of the calculation of the LRAMVA balance are presented in the third party report prepared by IndEco Strategic Consulting Inc., *PUC Distribution Inc. 2013-2016 LRAMVA* (attached in Appendix 7) and in the OEB LRAMVA work form. Of note is that savings were allocated to rate classes based on project specific results, and carrying charges were calculated using OEB approved interest rates. Interest rates from the present to April 2018 were assumed to remain constant.

Table 4-58 summarizes the LRAMVA amounts by customer class.

Table 4-58 LRAMVA by Customer Class

Customer Class	Billing Unit	Principal ($)	Carrying Charges ($)	Total LRAMVA ($)
Residential	kWh	$67,238	$188	$67,426
GS<50 kW	kWh	$255,590	$9,166	$264,755
GS 50 to 4,999 kW	kW	$82,129	$2,509	$84,638
Unmetered Scattered Load	kWh	-$1,397	-$53	-$1,450
Sentinel Lighting	kW	-$1,051	-$40	-$1,091
Street Lighting	kW	$60,586	$812	$61,398
Total		**$463,095**	**$12,582**	**$475,677**

PUC Distribution proposes to recover these amounts over one year. Table 4-59 below presents the proposed LRAMVA rate riders as calculated in the 2018 COS Rate Generation Model for PUC Distribution customers.

Table 4-59 - Proposed LRAMVA rate riders PUC

Customer class	**Billing determinant**	**LRAMVA amount**	**Forecast load**	**Proposed rate rider**
Residential	kWh	$67,426		$0.0000
GS<50 kW	kWh	$264,755		$0.0000
GS 50 to 4,999 kW	kW	$84,638		$0.0000
Unmetered scattered load	kWh	-$1,450		$0.0000
Sentinel lighting	kW	-$1,091		$0.0000
Street lighting	kW	$61,398		$0.0000

APPENDIX 1

App. 2-JA OMA Summary Analysis

Appendix 2-JA
Summary of Recoverable OM&A Expenses

	Last Rebasing Year (2013 Board-Approved)	Last Rebasing Year (2013 Actuals)	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Operations	$ 3,560,312	$ 3,667,835	$ 3,558,777	$ 3,702,949	$ 3,771,352	$ 3,752,937	$ 4,026,057
Maintenance	$ 1,978,405	$ 2,324,284	$ 2,214,631	$ 2,274,649	$ 2,206,518	$ 2,103,645	$ 2,186,573
SubTotal	**$ 5,538,717**	**$ 5,992,119**	**$ 5,773,408**	**$ 5,977,598**	**$ 5,977,870**	**$ 5,856,582**	**$ 6,212,629**
%Change (year over year)			-3.6%	3.5%	0.0%	-2.0%	6.1%
%Change (Test Year vs Last Rebasing Year - Actual)							3.7%
Billing and Collecting	$ 1,163,141	$ 1,274,108	$ 1,373,301	$ 1,417,758	$ 1,572,173	$ 1,618,876	$ 1,575,376
Community Relations	$ 544,548	$ 501,391	$ 557,701	$ 670,544	$ 626,657	$ 741,795	$ 618,800
Administrative and General	$ 2,706,539	$ 4,438,267	$ 3,332,931	$ 3,211,923	$ 3,188,235	$ 3,378,987	$ 3,549,028
SubTotal	**$ 4,414,229**	**$ 6,213,766**	**$ 5,263,933**	**$ 5,300,225**	**$ 5,387,065**	**$ 5,739,658**	**$ 5,743,204**
%Change (year over year)			-15.3%	0.7%	1.6%	6.5%	0.1%
%Change (Test Year vs Last Rebasing Year - Actual)							-7.6%
Total	**$ 9,952,946**	**$ 12,205,885**	**$ 11,037,341**	**$ 11,277,823**	**$ 11,364,935**	**$ 11,596,240**	**$ 11,955,833**
%Change (year over year)			-9.6%	2.2%	0.8%	2.0%	3.1%

	Last Rebasing Year (2013 Board-Approved)	Last Rebasing Year (2013 Actuals)	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year
Operations	$ 3,560,312	$ 3,667,835	$ 3,558,777	$ 3,702,949	$ 3,771,352	$ 3,752,937	$ 4,026,057
Maintenance	$ 1,978,405	$ 2,324,284	$ 2,214,631	$ 2,274,649	$ 2,206,518	$ 2,103,645	$ 2,186,573
Billing and Collecting	$ 1,163,141	$ 1,274,108	$ 1,373,301	$ 1,417,758	$ 1,572,173	$ 1,618,876	$ 1,575,376
Community Relations	$ 544,548	$ 501,391	$ 557,701	$ 670,544	$ 626,657	$ 741,795	$ 618,800
Administrative and General	$ 2,706,539	$ 4,438,267	$ 3,332,931	$ 3,211,923	$ 3,188,235	$ 3,378,987	$ 3,549,028
Total	**$ 9,952,946**	**$ 12,205,885**	**$ 11,037,341**	**$ 11,277,823**	**$ 11,364,935**	**$ 11,596,240**	**$ 11,955,833**
%Change (year over year)			-9.6%	2.2%	0.8%	2.0%	3.1%

	Last Rebasing Year (2013 Board-Approved)	Last Rebasing Year (2013 Actuals)	Variance 2013 Board-approved – 2013 Actuals	2014 Actuals	Variance 2014 vs. 2013 Actuals	2015 Actuals	Variance 2015 vs. 2014 Actuals	2016 Actuals	Variance 2016 Actuals vs. 2015 Actuals	2017 Bridge Year	Variance 2017 Bridge vs. 2016 Actuals	2018 Test Year	Variance 2018 Test vs. 2017 Bridge
Operations	$ 3,560,312	$ 3,667,835	$ 107,523	$ 3,558,777	-$ 109,058	$ 3,702,949	$ 144,172	$ 3,771,352	$ 68,403	$ 3,752,937	-$ 18,415	$ 4,026,057	$ 273,120
Maintenance	$ 1,978,405	$ 2,324,284	$ 345,879	$ 2,214,631	-$ 109,653	$ 2,274,649	$ 60,018	$ 2,206,518	-$ 68,131	$ 2,103,645	-$ 102,873	$ 2,186,573	$ 82,927
Billing and Collecting	$ 1,163,141	$ 1,274,108	$ 110,967	$ 1,373,301	$ 99,193	$ 1,417,758	$ 44,457	$ 1,572,173	$ 154,415	$ 1,618,876	$ 46,703	$ 1,575,376	-$ 43,500
Community Relations	$ 544,548	$ 501,391	-$ 43,157	$ 557,701	$ 56,310	$ 670,544	$ 112,843	$ 626,657	-$ 43,887	$ 741,795	$ 115,138	$ 618,800	-$ 122,995
Administrative and General	$ 2,706,539	$ 4,438,267	$ 1,731,728	$ 3,332,931	-$ 1,105,336	$ 3,211,923	-$ 121,008	$ 3,188,235	-$ 23,688	$ 3,378,987	$ 190,752	$ 3,549,028	$ 170,041
Total OM&A Expenses	$ 9,952,946	$ 12,205,885	$ 2,252,939	$ 11,037,341	-$ 1,168,544	$ 11,277,823	$ 240,482	$ 11,364,935	$ 87,112	$ 11,596,240	$ 231,305	$ 11,955,833	$ 359,593
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)													
Total Recoverable OM&A Expenses	$ 9,952,946	$ 12,205,885	$ 2,252,939	$ 11,037,341	-$ 1,168,544	$ 11,277,823	$ 240,482	$ 11,364,935	$ 87,112	$ 11,596,240	$ 231,305	$ 11,955,833	$ 359,593
Variance from previous year				-$ 1,168,544		$ 240,482		$ 87,112		$ 231,305		$ 359,593	
Percent change (year over year)				-10%		2%		1%		2%		3%	
Percent Change: Test year vs. Most Current Actual								5.20%					
Simple average of % variance for all years								-2.05%					2%
Compound Annual Growth Rate for all years													-0.4%
Compound Growth Rate (2016 Actuals vs. 2013 Actuals)								-2.35%					

APPENDIX 2

App. 2-JB OMA Cost Drivers

Appendix 2-JB
Recoverable OM&A Cost Driver Table[1, 3]

OM&A	Last Rebasing Year (2013 Actuals)	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year
Reporting Basis	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Opening Balance[2]	$ 9,952,946	$ 11,037,340	$ 11,277,823	$ 11,364,937	$ 11,596,241
Salaries, Wages & Benefits	$416,110	$373,054	$50,665	($56,405)	$339,235
Administrative	($55,701)	$46,586	$24,712	($29,985)	($5,205)
Training	($18,740)	($1,855)	($50,130)	$67,417	$6,395
Material	$34,342	($84,896)	$93,964	($84,619)	$0
Trucking/Equipment	$24,429	$400	$28,557	$25,389	($0)
Bad Debt Expense	$74,345	$53,146	$207,209	($41,704)	($87,473)
Community Relations	($54,077)	$34,152	($41,472)	$104,316	($11,547)
Building	$1,486,260	($126,779)	($21,395)	$41,352	$42,331
Insurance	$47,521	$4,114	($5,801)	($62,932)	($0)
Property Taxes	$3,241	$4,906	$4,858	$4,651	$1,022
Outside Services	$232,027	($40,144)	($126,376)	$99,127	$9,834
Postage	($14,738)	($2,687)	($27,132)	$44,320	$0
Professional Fees	$77,491	$19,009	($55,553)	$71,996	$60,000
Memberships, Licenses, Fees	$7,341	($2,829)	$466	($6,361)	$0
Computers	($28,417)	($38,616)	$39,283	$20,348	$0
Telephone/Fibre	$25,645	$7,503	($30,335)	$26,149	$0
Income Tax	($4,141)	($4,581)	($4,404)	$8,245	$5,000
Closing Balance[2]	$ 12,205,886	$ 11,277,823	$ 11,364,937	$ 11,596,241	$ 11,955,833

APPENDIX 3

App. 2-JC OMA Programs

Appendix 2-JC
OM&A Programs Table

Programs	Last Rebasing Year (2013 Board-Approved)	Last Rebasing Year (2013 Actuals)	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year	Variance (Test Year vs. 2016 Actuals)	Variance (Test Year vs. Last Rebasing Year (2013 Board-
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Operations									
Overhead Lines	$ 891,022	$ 886,027	$ 999,996	$ 833,710	$ 913,151	$ 977,516	$ 970,784	57,634	79,762
Underground Lines	$ 99,541	$ 103,879	$ 204,384	$ 194,355	$ 183,526	$ 157,706	$ 204,473	20,946	104,931
Operations Supervisory	$ 575,828	$ 677,616	$ 607,190	$ 661,003	$ 622,028	$ 649,055	$ 646,625	24,597	70,797
Load Dispatching	$ 255,221	$ 269,912	$ 252,338	$ 223,194	$ 232,038	$ 199,331	$ 214,485	-17,553	-40,736
Stations	$ 848,217	$ 905,156	$ 741,856	$ 747,612	$ 733,615	$ 798,954	$ 930,301	196,686	82,084
Transformers	$ 14,242	$ 8,202	$ 1,013	$ 3,984	$ 15,664	$ 17,276	$ 9,257	-6,408	-4,986
Meters	$ 423,008	$ 369,650	$ 319,706	$ 485,787	$ 550,630	$ 497,223	$ 584,371	33,742	161,364
Transmission	$ 1,136	$ 43,834	$ 38,620	$ 40,955	$ 50,381	$ 82,221	$ 83,563	33,182	82,427
Miscellaneous Operating	$ 452,096	$ 403,559	$ 397,481	$ 512,349	$ 470,320	$ 373,656	$ 382,197	-88,122	-69,899
Sub-Total	3,560,312	3,667,836	3,562,584	3,702,949	3,771,353	3,752,937	4,026,057	254,704	465,744
Maintenance									
Overhead Lines	$ 1,332,909	$ 1,688,546	$ 1,576,853	$ 1,288,038	$ 1,371,983	$ 1,343,956	$ 1,367,903	-4,080	34,994
Underground Lines	$ 258,634	$ 344,540	$ 306,555	$ 342,920	$ 360,487	$ 297,419	$ 304,847	-55,640	46,213
Stations	$ 265,799	$ 190,299	$ 243,581	$ 350,955	$ 345,773	$ 348,351	$ 339,888	-5,885	74,088
Transformers	$ 46,920	$ 22,017	$ 27,815	$ 211,054	$ 71,121	$ 32,374	$ 121,563	50,442	74,643
Meters	$ 74,143	$ 78,882	$ 56,018	$ 81,682	$ 57,154	$ 81,546	$ 52,372	-4,782	-21,770
Sub-Total	1,978,405	2,324,284	2,210,823	2,274,649	2,206,518	2,103,645	2,186,573	-19,946	208,168
Customer Service									
Bad Debt Expense	$ 107,680	$ 182,025	$ 127,593	$ 181,321	$ 378,852	$ 350,000	$ 261,613	-117,239	153,933
Customer Billing	$ 757,150	$ 811,476	$ 966,425	$ 888,033	$ 851,360	$ 914,837	$ 962,453	111,093	205,303
Customer Collections	$ 298,311	$ 280,607	$ 279,283	$ 348,403	$ 341,961	$ 354,038	$ 351,309	9,348	52,998
Community Relations	$ 544,548	$ 501,391	$ 557,701	$ 670,544	$ 626,657	$ 741,795	$ 618,800	-7,858	74,251
								0	0
Sub-Total	1,707,690	1,775,499	1,931,002	2,088,302	2,198,830	2,360,671	2,194,175	-4,655	486,486
Administration									
Income Tax	$ 50,202	$ 46,062	$ 40,740	$ 36,160	$ 31,755	$ 40,000	$ 45,000	13,245	-5,202
Insurance	$ 61,588	$ 147,363	$ 198,627	$ 205,612	$ 198,796	$ 131,136	$ 127,642	-71,154	66,054
LEAP	$ 19,054	$ 19,873	$ 22,610	$ 22,926	$ 23,270	$ 24,000	$ 24,000	730	4,946
Audit, Legal & Consulting	$ 116,025	$ 134,157	$ 230,840	$ 227,542	$ 139,566	$ 255,252	$ 209,185	69,619	93,160
Regulatory Affairs	$ 206,943	$ 297,503	$ 121,885	$ 149,856	$ 246,739	$ 350,292	$ 405,761	159,021	198,818
Building	$ 512,532	$ 2,005,468	$ 823,330	$ 653,778	$ 699,549	$ 653,602	$ 741,040	41,490	228,508
Administrative	$ 1,740,196	$ 1,787,842	$ 1,894,898	$ 1,916,048	$ 1,848,560	$ 1,924,705	$ 1,996,402	147,842	256,206
Sub-Total	2,706,539	4,438,267	3,332,931	3,211,923	3,188,235	3,378,987	3,549,028	360,793	842,489
Miscellaneous								0	0
Total	**9,952,946**	**12,205,886**	**11,037,340**	**11,277,823**	**11,364,937**	**11,596,241**	**11,955,833**	**590,896**	**2,002,887**

APPENDIX 4

App. 2-K Employee Costs

Appendix 2-K
Employee Costs

	Last Rebasing Year - 2013- Board Approved	Last Rebasing Year - 2013- Actual	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year
Number of Employees (FTEs including Part-Time)[1]							
Management (including executive)	19.42	18.35	18.58	18.15	19.75	20.19	19.10
Non-Management (union and non-union)	67.57	69.27	69.64	66.47	65.17	65.51	65.05
Total	86.99	87.61	88.22	84.63	84.91	85.70	84.16
Total Salary and Wages including ovetime and incentive pay							
Management (including executive)	$ 1,917,059	$ 1,980,372	$ 2,072,404	$ 1,999,948	$ 2,164,199	$ 2,264,896	$ 2,219,285
Non-Management (union and non-union)	$ 4,130,942	$ 5,239,956	$ 5,556,363	$ 5,181,452	$ 5,102,891	$ 5,321,163	$ 5,475,807
Total	$ 6,048,001	$ 7,220,328	$ 7,628,767	$ 7,181,400	$ 7,267,090	$ 7,586,059	$ 7,695,092
Total Benefits (Current + Accrued) [2]							
Management (including executive)	$ 429,613	$ 396,127	$ 475,333	$ 513,666	$ 585,139	$ 572,644	$ 562,869
Non-Management (union and non-union)	$ 1,617,450	$ 1,393,211	$ 1,414,264	$ 1,386,930	$ 1,401,771	$ 1,455,969	$ 1,445,296
Total	$ 2,047,063	$ 1,789,338	$ 1,889,597	$ 1,900,596	$ 1,986,910	$ 2,028,613	$ 2,008,164
Total Compensation (Salary, Wages, & Benefits)							
Management (including executive)	$ 2,346,672	$ 2,376,499	$ 2,547,737	$ 2,513,614	$ 2,749,338	$ 2,837,540	$ 2,782,154
Non-Management (union and non-union)	$ 5,748,392	$ 6,633,167	$ 6,970,627	$ 6,568,382	$ 6,504,662	$ 6,777,132	$ 6,921,103
Total	$ 8,095,064	$ 9,009,666	$ 9,518,364	$ 9,081,996	$ 9,254,000	$ 9,614,672	$ 9,703,257

APPENDIX 5

App. 2-L Per Customer and Per FTE

Appendix 2-L

Recoverable OM&A Cost per Customer and per FTE [1]

	Last Rebasing Year - 2013- Board Approved	Last Rebasing Year - 2013- Actual	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
OM&A Costs							
O&M	$ 5,538,717	$ 5,992,119	$ 5,773,408	$ 5,977,598	$ 5,977,870	$ 5,856,582	$ 6,212,629
Admin Expenses	$ 4,414,229	$ 6,213,766	$ 5,263,933	$ 5,300,225	$ 5,387,065	$ 5,739,658	$ 5,743,204
Total Recoverable OM&A from Appendix 2-JB [5]	$ 9,952,946	$ 12,205,885	$ 11,037,341	$ 11,277,823	$ 11,364,935	$ 11,596,240	$ 11,955,833
Number of Customers [2,4]	33,071	33,351	33,348	33,370	33,395	33,490	33,585
Number of FTEs [3,4]	87	88	88	85	85	86	84
Customers/FTEs	380.17	380.66	378.02	394.33	393.28	390.78	399.08
OM&A cost per customer							
O&M per customer	167.48	179.67	173.13	179.13	179.00	174.88	184.98
Admin per customer	133.48	186.31	157.85	158.83	161.31	171.38	171.01
Total OM&A per customer	300.96	365.98	330.97	337.96	340.32	346.26	355.99
OM&A cost per FTE							
O&M per FTE	63,670.73	68,391.96	65,445.85	70,635.85	70,398.38	68,338.45	73,822.34
Admin per FTE	50,744.10	70,921.76	59,670.57	62,631.50	63,440.77	66,974.10	68,244.33
Total OM&A per FTE	114,414.83	139,313.71	125,116.42	133,267.35	133,839.15	135,312.56	142,066.67

APPENDIX 6

Corporate Purchasing Policy

1.0 Purpose

The Board of Directors of PUC Inc., PUC Services Inc., PUC Distribution Inc. and the Public Utilities Commission (collectively PUC) have the ultimate authority for all expenditures. The Boards delegate this authority to the Chief Executive Officer (CEO) through approved budgets or specific resolutions. This policy specifies the purchasing practices to be followed by all employees of PUC Services Inc. with respect to the procurement of goods and services for the operation of PUC.

2.0 Scope

This policy applies to all departments of PUC.

3.0 Goals of the Purchasing Policy

1) To purchase for PUC, required goods and services and to dispose of unusable, obsolete, worn out or scrapped goods in accordance with PUC's policies and procedures.
2) To ensure fair, open, transparent and accountable competitive processes are followed in the acquisition of goods and services from suppliers.
3) To maintain the confidentiality of supplier information.
4) To ensure compliance with all applicable laws and regulations (Ontario Disabilities Act, Discriminatory Business Practices Act, Occupational Health & Safety Act, etc.).
5) Where practical, to promote standardization, partnership arrangements, joint purchases, and avoid unnecessarily restrictive specifications.
6) As required, to provide goods and services to all user departments in the most expedient and economical manner, considering lifecycle cost, consistent with an ethical purchasing philosophy.
7) To achieve harmonious, productive, working relationships with all departments or functions within PUC. The purchasing activities cannot be effectively accomplished solely by the efforts of the Purchasing Department. Collaboration with other departments and individuals within PUC is vital to the success of the business.
8) To maintain adequate quality standards set in conjunction with user departments on materials and services in order to meet or exceed our customers' requirements.
9) To promote reduction in the amount of waste requiring disposal through the purchase of environmentally responsible goods and services.
10) To promote the procurement of all goods and services from reputable and ethical vendors. The success of PUC depends on its skill in locating and/or developing vendors, analyzing vendor capabilities, and then selecting the appropriate vendor. Only if the final selection results in vendors who are both responsible and reliable will PUC obtain the items it needs at the lowest overall cost.
11) To maintain inventories at levels capable of sustaining operations without committing PUC to undue financial investments.
12) To enable local enterprises to compete successfully for PUC contracts.

4.0 Code of Conduct

In accordance with PUC's Code of Conduct employees involved in the purchasing process may not accept gifts from vendors. Nominal promotional items such as pens, calendars, t-shirts, ball caps, etc. are excluded from this ban.

In addition the procurement process should follow the principles advocated by the Supply Chain Management Association of Canada.

For greater clarity, if an employee has any pecuniary interest in relation to any purchase of goods or services, the employee shall immediately disclose the interest to their supervisor and shall not take part in the purchasing decision or in any way influence the purchasing decision.

5.0 Social Procurement Philosophy

PUC is committed to receiving the "best value" for its money, i.e., to purchase the best services and products at the most competitive price. In order to leverage its resources to advance the community in which its customers live, PUC considers "best value" to include the generation of positive social benefits in addition to high quality and competitive price. PUC strives to enable local entities to compete for PUC contracts, increase opportunities for local entities to be successful bidders and to work with out-of-town suppliers to maximize the utilization of local resources.

6.0 Health & Safety

1) All purchases must comply with all applicable health & safety standards, codes, regulations and organizational specifications.

2) All suppliers of "controlled products" as defined by the Workplace Hazardous Materials Information System (WHIMIS) must meet the requirements of the Occupational Health & Safety Act, and are subject to the requirements of the Regulations for Industrial Establishments.

3) No new "designated product" will be purchased without knowledge of the Director, Safety and Environment or his designate and the Joint Health & Safety Committee. See PUC's Workplace Hazardous Material Control Program.

4) Materials required for the electrical distribution system must be in accordance with Ontario Regulation 22/04 and PUC's Electrical Distribution Safety Program. (reference EDS-P10 Purchasing Approved Equipment)

5) All contracts for services will comply with the Occupational Health & Safety Act and PUC's Health and Safety policies.

   5.1 Safety Prequalification is the process used to minimize the amount of risk associated with hiring contractors. This process ensures each contractor demonstrates the basic general requirements to ensure workplace safety culture and to comply with the regulations put in place by the Ontario Occupational Health and Safety Act and its Regulations. See PUC's Contractor Policy.

   5.2 In addition, the hiring supervisor (requisitioner) is accountable to assess the potential risk associated with the work. Additional safety information may be needed depending on risk level; this can be accomplished by completing the Contractor Checklist found in the Contractor Policy.

7.0 Definitions

1) **Approved vendors:** Vendors or suppliers who may have previously provided goods and/or services to PUC or who have met departmental prequalification requirements, have been through regular assessments and are on the Approved Supplier/Contractor List.

2) **Bidders or Vendors:** Contractor, wholesaler, distributor, service provider or any outside entity competing for corporate business. For the purpose of this policy these terms are used interchangeably and refer to the same entity.

3) **Blanket Purchase Order:** A contract between PUC and a vendor for the supply of repetitively ordered specified goods or services at a specified price but not specified quantity. The term of this contract will cover no more than a one (1) year period but there can be options for extensions.

4) **Direct Purchase:** Purchase not made with petty cash, credit card or purchase requisition. Invoice approval follows PUC's Signing Authority Policy.

5) **Emergency**: A situation where immediate action is required to avoid jeopardizing operations, disrupting service to the public, or threatening the health and safety of staff or the public.

6) **Formal Competitive Bidding (Tenders, Request for Quotes or Proposals, Request for Prices)**: Procurement of goods/services, with bid opened in private and read at a predetermined time and place. The requisitioning party and at least one other person must be present at all tender openings along with the Purchasing Agent or designate. All submissions must be sealed as per the tender request package.

7) **Non-competitive procurement:** refers to an acquisition from a:
   - Sole Source, or
   - The item is an item of required design or is a proprietary or patented item, or
   - There is a need for compatibility with goods and services previously acquired and there is no reasonable alternatives, or
   - A reasonable attempt to identify competition has been unsuccessful.

8) **Preferred vendor or contractor:** A vendor or contractor that has a continuing arrangement to provide PUC with products or services. In addition, consideration of the following factors may apply: ability and experience to perform the work required; record of past performance with PUC; finance and technical resources; knowledge of PUC operations, systems and services; and compatibility with other goods and services of PUC.

9) **Prequalification:** A procurement process used to prequalify vendors for subsequent participation in an invitational Request for Proposal or Request for Quotation/Tender. Responses from proponents are evaluated against selection criteria set out in the solicitation, and a short list of pre-qualified proponents is created. Such could also be used for ongoing contract work of a lesser value.

10) **Purchase Order:** A legal document between PUC and a vendor to supply a specific quantity of goods or a specific set of services defined by such things as time period, location and price.

11) **Purchase Requisition**: A request to purchase, initiated by an employee, which defines the purchase specifications and requirements.

12) **Sole Source**: Recommended supply source where there is only one source of supply that meets the requirements.

13) **Specification:** A document package comprised of but not limited to technical provisions, safety rules, special provisions and other contract terms and conditions which must be satisfied by the contractor or supplier in performing the work. Specifications should be detailed but, where possible, not brand specific to allow for potential vendors to provide alternatives in the event an equal or better-proven product or method is available and shall not deter a competitive process.

14) **Technical Provisions**: The technical portion of the specification which relates to drawings, quality, design, standards, and description or by sample is the responsibility of the user department. Once established this information shall be retained in the appropriate filing system.

15) **Tender:** A formal request for sealed bids for the supply of goods or services in response to a formal solicitation process (advertised or not). For certainty, a Tender may include a Request for Proposal, a Request for Tender, a Request for Quotations, and any other document that is generally considered to facilitate the tendering process. Rules of the Tender are found in the request for Tender document and will govern the conduct of the various parties.

16) **Terms and Conditions:** Written provisions that determine the nature and scope of an agreement or contract and the responsibility and remedies of the parties to the agreement or contract.

17) **Two Envelope Method**: Bids are received in two separate envelopes. The first envelope contains technical and qualitative information and is opened and evaluated first. The second envelope contains price information and will be opened and evaluated after the information in the first envelope has been evaluated in accordance with the request for proposal documents.

8.0 Purchasing Levels and Methods

	Value of Commitment	Purchase Method (minimum requirement)	Process Options
8.1	Over $100,000	Formal Competitive Bidding	Requisition/Purchase Order/Contract
8.2	$25,001 to $100,000	Formal request by invitation for quotation/proposal - written proposal to be signed and sealed or sent to purchasing dept. “bids” e-mail address (3 minimum) (invitation)	Requisition/Purchase Order
8.3	$2,500 to $25,000	Informal Request for quotation/proposal (minimum of 3) which may be through the Purchasing Department	Requisition/Purchase Order
8.4	Under $2,500	No Quotes	Credit Card/Petty Cash/Direct Purchase/Requisition/Purchase Order

<u>IT Purchases</u>
All purchases of IT hardware, software and services must receive advisory approval from the Manager of IT and Communications in order to enable tracking of systems and to maintain Corporate IT standards.

<u>Emergency Purchases</u>
For a situation where immediate action is required to avoid jeopardizing operations, disrupting service to the public, or threatening the health and safety of staff or the public, purchases can be made by any method available without regard to the dollar value limits. Subsequent to the emergency situation the purchaser shall justify the purchase and the purchase will proceed through the normal approval process and according to the Signing Authority Policy before payment.

<u>Non-competitive procurement</u>
Written price quote and/or proposal is required prior to purchase. All sole source purchases require the approval of the President.

<u>Budget Requirement</u>
All purchases are subject to the availability and identification of funds in the approved budget.

<u>Other Policies</u>
All purchases are subject to the signing authority policy and credit card policy as applicable.

<u>Excluded Purchases</u>
The purchasing methods described in this section do not apply to the items listed in Appendix A.

8.1. Over $100,000 in value – Formal Competitive Bidding

PUC will call Tenders when the total expenditure of goods and services is estimated to be more than $100,000. Tenders may be called at a lesser dollar amount where deemed warranted.

In estimating the value of goods and services to determine if the purchase is within the tendering limit, the following criteria will be used:

a. The expenditure must be related to a whole or complete job, item or service.
b. The purchase must not be segmented or divided in a manner that would circumvent the tendering process.

The act of tendering is an important segment of PUC's Purchasing Policy in that it ensures the following:

1) That PUC receives the benefit of competitive pricing.
2) It makes the provision of goods and services to PUC available to a wide range of business organizations.

Split awards may be made when advantageous to do so.

When a tender is awarded a purchase order or contract will be created.

Tenders will be issued where the goods and services are fairly well defined and generally commercially available. In these cases price will be the major determining factor.

Professional services such as architects, engineers, banking, consultants, insurance brokers and adjusters and certain other goods and services such as computer hardware and software or property development cannot be as easily defined and specified as the procurement of other more generally commercially available goods and services. A Request for Proposal will be issued where the negotiation and award is based on demonstrated competence, professional qualifications and the technical merits of the submission at a fair price.

A Request for Proposal will follow the general procedures of the purchasing tender. The evaluation process for selection of the Supplier should be clearly outlined in each Request for Proposal. The two envelope method may be used for Request for Proposals where the true scope and complexity of the service is difficult to define in advance.

8.2. Purchases $25,001 to $100,000 in value - Request for Quotations

PUC will require a minimum of three (3) quotations when the total expenditure for goods and services is estimated to be more than $25,000 and less than $100,001. The quotations will be in the form of a written Request for Quotes/Proposal. The quotations will be secured by the Purchasing Department and shall be in writing and sealed or sent to the purchasing department “bids” e-mail address. The quotes shall be analyzed by the requisitioning department who justify the selected quotation. If after reasonable effort only a lessor number of quotations are obtained, approval to proceed is required from the VP level. The quotations shall be retained by the Purchasing Department. The requisitioning department shall forward an approved requisition to the Purchasing Department to issue a purchase order.

8.3. Purchases $2,500 to $25,000 in value – Informal Request for Quotations

PUC will require a minimum of three (3) quotations when the total expenditure for goods and services is estimated to be more than $2,5~~10,0~~00 and less than $25,001. The quotations may be in the form of a Request for Quotes/Proposal or an informal solicitation of quotes. The quotations will be secured by the Requisitioning department or the Purchasing Department and shall be in writing. The quotes shall be analyzed by the requisitioning department who justify the selected quotation. If after reasonable effort only a lessor number of quotations are obtained, approval to proceed is required from the VP level. The quotations shall be retained by the Purchasing Department. The requisitioning department shall forward an approved requisition to the Purchasing Department to issue a purchase order.

8.4. Purchases under $2,500

The purchaser of goods or services under $2,500 must be able to demonstrate that the purchase was made at fair value. Purchases of goods in this cost range can be make using petty cash (small dollar amounts), PUC credit card (as per the terms of the Credit Card Policy), Direct Purchase or requisition/purchase order method. Requisitions must be approved as per PUC's Signing Authority Policy before a purchase order can be created. Direct Purchases, Credit Card purchases and Petty Cash purchases are subject to PUC's Signing Authority Policy.

8.4.1. Credit Card Purchases

Refer to the PUC Services' Credit Card Policy for specific procedures. The purpose of the Credit Card is to provide an efficient, cost effective method of purchasing and processing small dollar or 'one off' type purchases.

Items purchased with credit cards require appropriate supporting documentation and approvals and have specified dollar limits. (See PUC's Credit Card Policy)

9.0 Other Purchasing Practices

9.1 Electronic Requisitions and Approvals

Purchase requisitions are generated using the in-house requisitioning application (Cayenta) to initiate the purchasing process. See Appendix C for a description of the purchasing process.

9.2 Consortiums/Co-Operative Purchasing

Cooperative purchasing or an arrangement between two or more entities (Consortiums) to tender commonly used goods or services together is encouraged in an effort to reduce costs by purchasing in larger volumes. The general principles of PUC's purchasing policy should be followed by any consortium that PUC participates with.

9.3 Vendor Credit Applications

The Purchasing Department is responsible for completing credit check forms required by vendors.

9.4 Asset Disposal Procedure

The Manager of a department may declare goods as surplus or obsolete with the approval of the divisional VP. The Purchasing Department will determine if the goods can be used in other departments. If there is no corporate wide use for the goods, the Purchasing Department shall sell, exchange, donate or otherwise dispose of the goods according to guidelines established by the Purchasing Department. No employee who has responsibility for declaring goods surplus shall bid on or obtain any goods he or she has declared surplus.

9.5 Personal Purchases

No purchase shall be made by PUC which is personal to the person requesting the purchase and is not for PUC purposes.

9.6 Green Procurement Policy

PUC supports the purchase of environmentally preferred products. See Appendix D for PUC's green purchasing philosophy.

Approved: ______________________________ **Date:** ______________________

President & CEO

Revision History:

NOTE: A red line on the right side of document indicates a change		
Revision #	**Date**	**Description**

Appendix A

Expenditures Excluded from the Application of this Policy

The purchasing methods described in this policy do not apply to following goods and services:

- Training and education, courses, workshops, memberships, subscriptions, etc.
- Travel, meals, and accommodations
- Refundable employee expenses
- Medicals
- Damage claims
- Conservation and Demand Management, customer rebates or customer refunds
- Developer rebates and construction deposit refunds
- Wholesale electricity, transmission and connection invoices
- Electrical Safety Authority fees, rights-of-way, joint use agreement fees,
- Ontario Energy Board regulatory payments
- Payroll related payments , federal, provincial, municipal taxes and fees, vehicle license fees, and Payments in lieu of taxes (PIL's)
- Software license fees and annual maintenance fees (ongoing in nature after original award)
- Utility payments (hydro, cable, water, natural gas)
- Postage
- Debt retirement and Interest payments on debt
- Payments to Shareholders (including dividends)
- Charitable donations/Sponsorship
- Road reconstruction projects in conjunction with the City of Sault Ste. Marie

Appendix B

Tendering Process

Preparing a Tender Package

The Purchasing Department and the Requisitioner are both responsible for the preparation of the tender package:

The Requisitioner will:

- provide a complete statement of work and/or list of specifications which the item or service being purchased must meet;
- provide drawings, design details and schedules;
- detail the contract agreement and general conditions;
- detail supplementary conditions;
- detail a weighted scoring matrix to ensure awards are made to the bidder offering the best value;
- provide any addenda if necessary (prior to tender closing).

The Purchasing Department generally will:

- invite sealed Tenders by specific invitation and/or by public advertisement
- provide a standard Tender document on which the bidder will include the total price and other required information;
- provide a standard Tender covering letter establishing the date/time of Tender issuing and closing as well as place for receiving proposals;
- provide instruction to bidders detailing the how, when, where, and what form Tenders must be submitted;
- provide standard Terms of Conditions;
- send out the Tender package to bidders or post the Tender package electronically;
- obtain confirmation from the bidders as to their intent to participate;
- provide any addenda if necessary (prior to tender closing), and
- other relevant instructions as required.

General Rules to the Bidders

- No bids will be accepted after the Tender closing; late bids will be disqualified and returned, unopened, to the bidder.
- A new bid for the original unopened bid can be made, provided it is received before the bid closing date and time.
- Any inquiries made by the bidder must be directed electronically to the Purchasing Department or designate. The Purchasing Department along with the Requisitioner will respond. The inquiry and response will be formally issued to all bidders who have completed the confirmation of intent to participate.
- All other conditions of the Tender must be met.

Receipt of Tenders

All bids must be received at the location specified in the Tender document. Upon receipt of the Tender the receiver will date and time stamp and secure the Tenders.

- The minimum individuals attending the Tender opening meeting will be the Requisitioner, the Purchasing Agent and a third person;
- Bids will be opened and reviewed for acceptance;
- Any bid that does not satisfy the requirements may be disqualified;
- A Bid Summary Sheet will be completed;
- All bidders will be notified of the successful bidder.

Award of Contract

The Purchasing Department or its designate will notify the successful vendor, in writing, of the award of contract. If required, instructions about proceeding with the job will be detailed on the notification.

Unsuccessful bidders in a tender process can approach PUC to discuss where they can improve on their submissions and be debriefed on why they did not receive the award of contract. Details of the successful bid will remain confidential (price, etc.)

Preparation and Placement of Purchase Order

The Requestor will generate a purchase requisition and the Purchasing Department will prepare the contracts for signature. The Purchase Order will include the following information as appropriate:

- List the contract number
- a clear description of the product or services ordered;
- precise identification of type, class, and grade of the product; and
- any quality system standards which will apply.

Approved contracts are signed by the appropriate signing authority as per the signing authority policy, and then forwarded to the successful bidder for acceptance. The Requisitioning Department retains one copy of the contract and the original is filed in the Purchasing Department.

Guarantee of Contract Execution

a) Where required tenders >$50,000 using the services of contractors shall be accompanied by a tender deposit in the form of a certified cheque or irrevocable letter of credit payable to PUC Services Inc. in the amount of Five Thousand Dollars ($5,000.00). Such deposit shall be security to PUC Services Inc. that the Bidder, if successful, will execute the contract documents within two (2) weeks of award and will start Work as specified. Failure to execute the documents within two (2) weeks or failure to start Work as specified will result in forfeiture of the tender deposit. Tender deposits of unsuccessful Bidders will be returned within three (3) weeks after award of the contract. The tender deposit of the successful Bidder will be returned with the first progress certificate.

b) Suppliers may withdraw tenders/quotations prior to time of closing but not at any time thereafter. Bid deposits of any supplier withdrawing after time of closing shall be forfeited to PUC.

c) Prior to the commencement of the work, the successful bidder may be required to provide security in the form of a performance bond to guarantee the performance of a contract, a labour and material payment bond to guarantee the payment of labour and materials supplied in connection with a contract or an irrevocable letter of credit.

d) Other means to guarantee the execution of the contract may include surety bonds or other security deposits, progress payments and holdbacks.

e) All contracts awarded for supply of labour and/or equipment must present proof of insurance at stipulated levels. Bid documents must clearly indicate the insurance requirements to be provided and maintained until the termination of the contract by the successful bidder, including a cross liability clause endorsement certifying PUC is named as an additional insured. The insurance coverage shall indemnify and save harmless PUC, their agents and employees from and against all claims, demands, losses, costs, damages, actions, suits, or proceedings by third parties that arise out of, or are attributable to, the contractor's performance of the contract.

f) Prior to payment to a supplier, contracts awarded for supply of labour must present a Certificate of Clearance from the Workplace Safety and Insurance Board (WSIB) ensuring all premiums have been paid to the date of payment. It is the responsibility of the contractor to ensure that the Purchasing Department of PUC has, at all times, current copies of all required documents. Failure to do so may result in termination of contract. Clearance certificates must be refreshed every three months (for contracts with duration of three months or more).

g) All contracts shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein.

Bid Irregularities

Extreme care shall be exercised to ensure that Irregular Bids are handled in a manner which is fair to other bidders as well as the public.

The following are guidelines only, intended to illustrate some of the discretion allowed. The Purchasing Agent will review each case.

	<u>IRREGULARITY</u>	<u>RESPONSE</u>
1.	Late Bids	Automatic rejection, not opened and returned unopened to the bidder
2.	Unsealed Tender Envelopes	Automatic rejection
3.	Tenders received by Facsimile (FAX)	Automatic rejection
5.	Insufficient financial security (no deposit or bid bond or insufficient deposit or bid bond)	Automatic rejection unless insufficiency is trivial or insignificant
6.	Bids not completed in ink or in type	Automatic rejection
7.	Incomplete bids (part bids - all items not bid)	Automatic rejection unless part bid specifically permitted by tender documents
8.	Illegible or obscure bids or bids which contain additions not called for, erasures, alterations, errors or irregularities of any kind	May be rejected as informal
9.	Qualified bids (bids qualified or restricted by an attached statement)	Automatic rejection
10.	Bids received on documents other than those provided by PUC	Automatic rejection
11.	Bids containing minor clerical errors	48 hours to correct and initial errors
12.	Execution of Agreements to Bond - Bonding company corporate seal or signature missing from agreement to bond	Automatic rejection
13.	Execution of Bid Bonds (a) Corporate seal or signature of the bidder, or both, missing (b) Corporate seal or signature of bonding company missing	 48 hours to correct Automatic rejection
14.	Other Bid Security - Uncertified Cheques	Automatic rejection

15.	Tender Documents - Execution (a) Corporate seal or witness signature missing but Signing Officer signature present (b) Signing Officer signature missing (c) Corporate seal or witness affixed but Signing Officer signature missing	48 hours to affix Automatic rejection Automatic rejection
16.	Erasures, Overwriting or Strike-Outs which are not initialed: (a) Un-initialed changes to the tender documents which are minor (example: the tenderer's address is amended by over-writing but not initialed) (b) Unit prices in the Schedule of Prices have been changed but not initialed (c) Other mathematical errors which are not consistent with the unit prices	48 hours to initial 48 hours to initial 48 hours to initial corrections to be made by the Purchasing Department
17.	Failure to attend **mandatory** pre-submission meeting or visit	Automatic rejection
18.	Tender documents which suggest that the tenderer has made a major mistake in calculations of tender	Legal consultation on a case by case basis and a report to CEO.

Appendix C

The requisitioning employee is responsible for determining the need, specification, design or other technical data associated with a purchase as well as the following:

1) All user departments are to provide the Purchasing Department with sufficient information to complete a transaction as noted. Failure to provide this information could result in a delay of turnaround time. Sufficient lead time must also be given to allow completion of the purchasing process and delivery.

2) All purchases shall be in accordance with approved budgets.

3) The necessary technical specifications and details as may be required to form a quotation and/or Tender Call must be forwarded to the Purchasing Department.

4) The requisitioning department must assess the potential risk associated with contracted work and if necessary complete contractor prequalification.

5) A purchase requisition may be generated by any employee but must be approved electronically by the appropriate signing authorities and include the proper account coding. Non- compliance to the above will result in the return of the purchase requisition to the source and ultimately loss of lead time.

Purchasing Process

Purchase requisitions are generated using the in-house requisitioning application (Cayenta) to initiate the purchasing process. The following are the steps in the purchasing process:

1. Description of the Need

The requestor must provide an accurate description of the materials or services required. For services, a Statement or Scope of Work must be prepared. General Terms and Conditions and technical recommendations should be provided for significant expenditures to support the need.

2. Determination and Analysis of Possible Sources of Supply

All potential vendors must be assessed to determine if they have the capability to provide the equipment, material, supplies or services.

Prequalification may be a requirement. This may include a risk assessment requirement as in the case of the PUC’s Contractors Policy.

The Purchasing Department will attempt to ensure that any qualified person/company capable of supplying satisfactory goods and services has an equal opportunity to compete for the sale of products or services needed to support the requirements of PUC. Where prices are equal, determining factors may include conformity to specifications, record of deliveries and past performance of supplier's service and proximity of supply.

Some departments require cost estimates to determine whether or not to proceed with a project. Suppliers must be advised that these are study estimates only and any action on a purchase will go through the standard purchase process. Departments other than Purchasing may investigate pricing for their specialized technical needs when needed. However, all information, including alternate quotes, is to be submitted to the Purchasing Department for processing/filing.

3. Determination of Terms and Conditions

All purchase requisitions must include general terms and conditions specific for the type of product and/or service required. The requisitions must include the proper authorizations and account coding.

The Purchase Requisition is forwarded to the Purchasing Department who will review the requisition for completeness.

When Purchasing processes a purchase requisition the following steps are taken:

- Check for alternative items, if required. The Purchasing Department will make every effort to investigate alternative items that might be acceptable to the requisitioner's requirements.
- If the materials or services are to go out for Tender, the Tender process must be followed.
- Participate in evaluating the quotations submitted by the requisitioner (if any), reviewing requisitioner's request, delivery requirements and cost, and obtain requisitioner's input as needed.
- Complete the purchase order.
- Confirm the order with the vendor and requisitioner and secure delivery.

- Arrange to have the goods or services delivered to the requisitioner or to the Stores Department.

4. Preparation and Placement of Purchase Order

The Purchasing Department will be responsible for the creation and issuing of all Purchase Orders. A blanket purchase order can be used for the supply of repetitively ordered specified goods or services at specified a price but not specified quantity. The term of a blanket order will typically cover no more than a one (1) year period but there can be options for extensions.

Proper authorization in accordance with PUC's Signing Authority Policy must be obtained in advance of purchases. Purchase Orders initiated after the provision of goods or services and/or receipt of supplier invoices are a serious violation of this policy and will require additional levels of authorization.

5. Follow-up on and/or Expediting Order

The Purchasing Department will be responsible for expediting all outstanding orders. The Purchasing Department will be responsible for invoicing discrepancies and will work in cooperation with Accounts Payable and the requisitioner to resolve such issues.

6. Receipts and Inspection of Goods

All materials purchased must be received and inspected to ensure that the requirements of the Purchase Order have been met. If material is nonconforming, it must be isolated prior to further processing.

All packing slips for material not received at PUC's main warehouse must be forwarded to the Stores Department. in order to close the purchase order. This will allow for the timely processing of invoices for payment.

7. Clearance of the Invoice

All invoices will be paid by Accounting upon receipt of confirmation that the materials or services were received and acceptable and proper approvals are in place.

8. Change Order Request

A purchase order can only be changed if the requestor sends a new approved purchase request to the Purchasing Department requesting the change to the specific purchase order.

9. Records Management

All Purchasing records must be maintained by the Purchasing Department and/or the requesting employee/requester/originator as may be required. Documentation must be made available to the Purchasing Department as requested.

A copy of all approved Purchase Orders will be maintained on file in the corporate software.

For competitive processes, the Purchasing Department shall file, electronically or in hard copy, as appropriate, all documents associated with the procurement process and contract award (the solicitation document and any addendum and questions and answers; the supplier(s) proposal(s) and submission; the Purchase Orders; all contract related documents; and any other relevant supporting documentation), systematically for ease of reference and retrieval.

Proprietary and confidential information of suppliers will be safeguarded with appropriate care.

Appendix D

Green Purchasing Philosophy

The Purchasing Department's policy at PUC Services is to support the purchase of recycled and environmentally preferred products in order to minimize environmental impacts relating to our work. We recognize our employees can make a difference in favor of environmental quality. We strongly recommend the purchase of environmentally preferable products whenever they perform satisfactorily and are available at a reasonably competitive price. We encourage waste prevention, recycling and the use of recycled/recyclable materials through contractual relationships and purchasing practices with vendors, contractors and businesses.

"Environmentally Preferable Products" means products that have a lesser impact on human health and the environment when compared with competing products. This comparison may consider raw materials acquisition, packaging, distribution, reuse, operation and/or disposal of the product.

"Recycled Products" are products manufactured with waste material that has been recovered or diverted from the waste stream. Recycled material may be derived from post-consumer waste (material that has served its intended end-use and been discarded by a final consumer), industrial scrap, manufacturing waste and/or other waste that otherwise would not have been utilized.

Purchasing solicits the use of recycled and other environmentally preferred products (e.g. paper Products, including janitorial supplies, shop towels, hand towels, facial tissue, toilet paper etc.) in its procurement documents as appropriate. We also structure applicable contracts to offer and/or feature recycled-content products whenever possible, (e.g., office supplies and janitorial supplies).

The Purchasing Dept. supports PUC Services Environmental Policy and its commitment to making environmental protection an integral part of our planning, operating and purchasing decisions. We accomplish this by supporting the purchase of recycled and environmentally preferred products in order to minimize environmental impacts relating to our work.

Sincerely,
PUC Services Inc.

Noella Flood
Purchasing Agent

APPENDIX 7

IndEco PUC 2013-2016 LRAMVA report

IndEco

Strategic Solutions for a Changing World™

PUC Distribution Inc. 2013-2016 LRAMVA

PUC Distribution Inc. lost revenue related to Conservation and Demand Management

2013-2016

This document was prepared for PUC Distribution Inc. by IndEco Strategic Consulting Inc.

For additional information about this document, please contact:

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IndEco report B7142

20 July 2017

Contents

Introduction

The Lost Revenue Adjustment Mechanism (LRAM) was developed to remove a disincentive electricity local distribution companies (LDCs) may have to promote conservation and demand management (CDM) programs. CDM programs are designed to provide energy savings and peak demand reductions for the customers of LDCs, which directly impact the LDC's revenue. The LRAM allows LDCs to be compensated for lost revenue that resulted from CDM programs the LDC offered to its customers.

Starting in 2011, the Ontario Energy Board (OEB) authorized LDCs to establish an LRAM variance account (LRAMVA) to capture the impact of CDM programs on the revenue of LDCs. The variance in the LRAMVA is between the lost revenue due to independently verified load impacts of CDM and the lost revenue from any CDM impacts an LDC included in the LDC's load forecast.[1]

PUC Distribution Inc. (PUC) contracted with the Ontario Power Authority (OPA, which has now been merged into the Independent Electricity System Operator – IESO) to offer a suite of CDM programs to customers in a variety of rate classes for the 2011-2014 period and subsequently with the IESO for the 2015-2020 period. PUC is required to use "the most recent and appropriate final CDM evaluation report from the IESO in support of its lost revenue calculation."[2] The final 2016 annual verified results report is the most recent final CDM evaluation report available from the IESO. Thus, PUC may claim lost revenue from CDM programs up to and including 2016 in PUC's 2018 rate case (EB-2017-0071).

PUC disposed of lost revenues from 2011–2012 CDM programs in 2011–2012 in PUC's 2013 and 2014 rate cases. PUC included the impacts of CDM in the load forecast for PUC's 2013 cost of service rate case and estimated the CDM savings in 2013.[3] The LRAMVA Threshold estimated from 2011–2013 CDM programs in 2013 is compared to the calculated lost revenue from verified final CDM results. The difference between these two is the LRAMVA value PUC is claiming for 2013 – 2015. This report determines the variance account balance for the following revenue losses:

- Lost revenues in 2013 related to programs offered in 2011,
- Lost revenues in 2013 related to programs offered in 2012,

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[1] *Guidelines for Electricity Distributor Conservation and Demand Management*. Ontario Energy Board. April 26, 2012 (EB-2012-0003).

[2] *Filing Requirements For Electricity Distribution Rate Applications - 2016 Edition for 2017 Rate Applications - Chapter 2 - Cost of Service*, Ontario Energy Board. July 14, 2016.

[3] The LRAMVA Threshold is shown in Table 7 of the settlement agreement, which is appended to the OEB Decision and Order. (EB-2012-0162, p. 20 of the settlement agreement. Although the table is labeled as being only for 2012 and 2013 programs, the values shown are from Table 6 on the same page and include persistence from 2011, as well as from 2012 and 2013.

- Lost revenues in 2013 related to programs offered in 2013,
- Lost revenues in 2014 related to programs offered in 2011,
- Lost revenues in 2014 related to programs offered in 2012,
- Lost revenues in 2014 related to programs offered in 2013,
- Lost revenues in 2014 related to programs offered in 2014.
- Lost revenues in 2015 related to programs offered in 2011,
- Lost revenues in 2015 related to programs offered in 2012,
- Lost revenues in 2015 related to programs offered in 2013,
- Lost revenues in 2015 related to programs offered in 2014,
- Lost revenues in 2015 related to programs offered in 2015,
- Lost revenues in 2016 related to programs offered in 2011,
- Lost revenues in 2016 related to programs offered in 2012,
- Lost revenues in 2016 related to programs offered in 2013,
- Lost revenues in 2016 related to programs offered in 2014,
- Lost revenues in 2016 related to programs offered in 2015, and
- Lost revenues in 2016 related to programs offered in 2016.

The carrying charges on the above variances through April 2018 are also reported.

Methodology

In principle, the determination of lost revenues is a simple calculation:

LR = (CDM results – CDM results in the load forecast) * rate

In practice, it is somewhat more complicated than that because of the limitations of the information available to calculate CDM results, the different time periods of results data and the rate year, and the need to determine carrying charges on the lost revenues.

The most recent input assumptions currently available have been used to calculate the lost revenue values.

CDM results

From 2011 through 2016, PUC offered provincial programs in partnership with the Independent Electricity System Operator (IESO). PUC did not offer custom programs beyond the IESO programs.

IESO evaluation results

The IESO performs evaluations of all of its programs, which examine gross energy savings from the programs, and the net-to-gross ratio (NTGR), and then from those calculates net energy savings by initiative within program group (residential, business, industrial and low-income). Peak load reductions are also calculated, and reported in the same way.

Provincial results are allocated to individual LDCs based on each LDC's individual performance where possible, or through an allocation process.

The IESO reports energy savings and peak demand reductions, by initiative in the current year, adjustments to the previous year, based on updated validation, and contribution to total savings or reductions to the end of the 2011 to 2014 period and the 2015 to 2020 period. The savings and demand reductions for a particular year for a number of programs persist in the following years. The savings and demand reductions for demand response programs do not persist beyond the year in which those particular savings and demand reductions occur. The IESO was requested to provide the persistence into future years of savings and reductions for each program in each year.

These are the best, most definitive and defensible estimates of results associated with these programs, and incorporate the most appropriate estimates of results from the measures installed.

However, these data have some limitations, and require some adjustments for use in lost revenue calculations.

Allocating results to rate classes

The IESO reports results by 'program', within four main programs: residential, business (commercial and institutional), industrial and low-income. These only partially map onto rate classes. For initiatives that apply to more than one rate class, PUC staff estimated the split by rate class, drawing on participant-specific information where available. In 2016, IESO provided a project spreadsheet showing net results for each project in the Retrofit program. PUC staff identified the rate class associated with the project and thus net savings and demand reductions were allocated to rate classes.

Application of reported results

As previously mentioned, the IESO reports both energy savings and reductions in demand. Depending on the rate class, distribution revenue is based on either kilowatt-hours used, or the customer's monthly peak kilowatt use. For rate classes where the customer is charged for distribution by energy use (kWh), the IESO reported energy savings are used to calculate lost revenues related to CDM results. For customer classes where the LDC charges for distribution based on the customer's peak monthly demand (kW), the IESO reported demand reductions are used to calculate lost revenues related to CDM results[4]. The demand reductions in the IESO reports should be multiplied by a multiplier based on the number of months a specific program impacts a customer's peak demand. "The IESO indicated that the demand savings from energy efficiency programs shown in the Final CDM Results should generally be multiplied by twelve (12) months to represent the demand savings the distributor has experienced over the entire year…In the case of the Building Commissioning initiative, the demand savings provided in the Final CDM Results should only be multiplied by three (3) as these savings are related to space cooling and do not occur throughout the full year, but only during the summer months, typically."[5]

The OEB has decided that lost revenue cannot be claimed from the kW values reported by the IESO for the Demand Response 3 (DR3) program. "The monthly peak demand of a demand-billed customer used for billing purposes may not correspond with the demand response event; even if it did, the lost revenues would only be related to a difference between the customer's peak demand absent the demand response event and the next highest peak demand for the customer in that month… Since the IESO's evaluations cannot confirm the nature of the demand savings relative to the billing period for demand-billed customers, it is not appropriate that distributors be

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[4] The exception is street lighting retrofit projects. Street-lighting is billed by kW, but street lighting retrofit projects have no peak demand reductions associated with conservation measures. A special calculation is done for these, as described below.

[5] Ontario Energy Board, *Updated Policy for the Lost Revenue Adjustment Mechanism Calculation: Lost Revenues and Peak Demand Savings from Conservation and Demand Management Programs*, EB-2016-0182, May 19, 2016, p. 4.

credited with lost revenues from demand response programs, except for those situations where the distributor can explicitly demonstrate revenue impacts."[6]

Load reductions accounted for in the load forecast

In recent years, LDCs have tried to account for load losses due to CDM programs in their load forecasts, submitted as part of their Cost of Service applications. These forecasted reductions need to be deducted from load losses attributable to CDM programs to determine the final impact of CDM on revenues. That is, the impact is the *variance* between the results accounted for in the load forecast and the results attributable to the programs.

Overall impact of CDM on load, by rate class

The overall impact of CDM energy savings and demand reductions on load is calculated from the IESO energy savings and peak demand reductions, allocated by rate class. Finally the difference is calculated between the overall estimated impact on loads and the load reductions attributable to CDM that were captured in the most recent load forecast.

Distribution rates

Revenue impacts to the LDC associated with CDM are calculated using the distribution volumetric rate. Most other rate components (e.g. service charges, global adjustment, transmission charges) are either fixed charges or pass-throughs for the utility that do not affect the LDC's revenues. An exception is for certain rate riders related to taxes, and these are added to the distribution volumetric rates for lost revenue calculations, where applicable.

For most electricity distribution utilities in Ontario, including PUC, distribution rates are set for the period from 1 May to 30 April of the next year. CDM results are reported for the calendar year, so average rates for the calendar year need to be calculated. For simplicity, the average rate is estimated based on the rate being four twelfths of the previous year's rate (for January through April), and eight twelfths of the current year's rate (for May through December).

Lost revenues variance

Lost revenues in a particular rate class are the product of the savings or demand reductions in that class, less what was accounted for in the load forecast, multiplied by the average rate for that class in the calendar year for which the energy savings or demand reductions were

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[6] Ibid. p. 7.

reported.[7] The variance is the difference between these lost revenues and the quantity of CDM in the load forecast, or what is called 'the LRAMVA threshold'.

Because these revenues are lost throughout the year, and are only recovered through rate riders in subsequent years, the Ontario Energy Board has permitted the LDCs to claim carrying charges on these lost revenues at a rate prescribed by the OEB, and published on the Board's website. The carrying charges are simple interest, not compounded and are calculated on the monthly lost revenue balance. Because the IESO final results estimates are reported annually, and monthly estimates are not available, the incremental results are assumed to be equally distributed across the months. So 1/12 of the annual results are allocated to each month of the year.

Carrying charges accrue from the time of the results, until disposition.

The LDC reports these lost revenues on its financial statements in Account 1568, and the associated rate class-specific sub-accounts.

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[7] Where distribution rates are monthly rates for the peak kW in that month, the annual loss of revenue is the monthly rate times the number of months it applies to – usually twelve.

Results

Following the methodology described above, lost revenues were calculated for PUC. The results reference tables provided in the completed LRAMVA workform that uses the OEB's template.

CDM results

IESO evaluation results

The most recent and appropriate final CDM evaluation reports from the IESO were used in support of the lost revenue calculations. A working Microsoft Excel file copy of each IESO evaluation report has been filed separately by PUC. The net verified final 2011-2014 results can be found in Table 1 of the *Verified 2011-2014 Final Results Report for PUC Distribution Inc.* file released by the IESO on September 1, 2015. The net adjustments to verified final 2011, 2012, and 2013 results can be found in Table 2 of the *Verified 2011-2014 Final Results Report for PUC Distribution Inc.* file released by the IESO on September 1, 2015. These data are reproduced in Table 4-a, b, c and d of the OEB workform for 2011, 2012, 2013, and 2014 respectively.

The net verified final 2015 and 2016 results, including adjustments in 2016 to 2015 results can be found in the "Net Incremental First Year Energy Savings" and "Net Incremental First Year Peak Demand Savings" sections of the "LDC Progress" tab in the *Final Verified 2016 Annual LDC CDM Results Report PUC Distribution Inc.* file released by the IESO on June 30, 2017. These data are reproduced in Table 5-a and 5-b for 2015 and 2016, respectively.

The IESO provided PUC with persistence data for 2011-2014 results and 2011-2013 adjustments at the initiative level. The data provided are presented in Tables 4a – 4d of the OEB LRAMVA work form that is filed with this document.

The IESO provided persistence data for 2015 and 2016 as part of the standard results report. These are reproduced in Tables 5a and 5b on Tab 5 of the OEB workform.

Street lighting project

Starting in 2015, the City of Sault Ste. Marie undertook a project under the Retrofit Program to retrofit streetlights to a more energy efficient light emitting diode (LED) technology.

The IESO has included the calculated kilowatt hours (kWh) of energy savings from the street lighting project in PUC's 2016 results.. These values are included in the table below:

Year	Gross savings (kWh)	Net to gross ratio	Net savings (kWh)
2015	106,605	0.86	91,702
2016	4,004,783	0.83	3,310,019

The street lighting account is billed based on kilowatts (kW) of demand. The street lighting retrofit project is being implemented in stages and kW reductions have been applied to the municipality's street lighting account starting in December 2015. The customer bills/billing data showing the value of 1,782 kW used for billing prior to the street lighting upgrade and the value of 1,688.617 kW used for billing in December 2015 to reflect the first phase of the street lighting upgrade can be found on Tab 8 of the OEB LRAMVA workform.

These changes in demand for billing purposes are not captured in the IESO report on reductions because that report only considers demand reductions during peak hours, when streetlights are not in use, so have been calculated separately.

As the street lighting rate class is billed by kW, the calculated kWh savings from the Retrofit project do not impact PUC's revenue. Thus, the calculated kWh of savings have been manually removed from the 2015 Retrofit program results for lost revenue calculations. The actual 2015 and 2016 lost revenue from the street lighting retrofit project has been calculated directly by multiplying the demand reduction from the project by the appropriate rate.

Allocating results to rate classes

PUC provided information on the allocation of results to rate classes. In most cases, the allocation is straightforward. Initiatives that can span multiple rate classes include Retrofit, Building Commissioning, New Construction, Energy Audit, Demand Response 3, Process & Systems Upgrades, Monitoring & Targeting, Energy Manager, Electricity Retrofit Incentive Program and High Performance New Construction. No allocation was provided for programs for which PUC has no program results.

PUC bills customers in different rate classes using different volumetric units, either kilowatt hours (kWh), or customer peak monthly kilowatts (kW). The rate classes (and billing units) for PUC are:

- Residential (kWh)
- GS <50 kW (kWh)
- GS 50 to 4,999 kW (kW)
- Unmetered Scattered Load (kWh)
- Sentinel Lighting (kW)

- Street Lighting (kW)

Table 4a (beginning at column Y) of the OEB LRAMVA work form shows the percentage allocation by rate class for the persistence of 2011 results and adjustments. Table 4b of the OEB LRAMVA work form shows the percentage allocation by rate class for the persistence of 2012 results and adjustments. Table 4c of the OEB LRAMVA work form shows the percentage allocation by rate class for 2013 results and adjustments. Table 4d of the OEB LRAMVA work form shows the percentage allocation by rate class for 2014 results. Table 5-a and b of the OEB LRAMVA work form shows the percentage allocation by rate class for 2015 and 2016 results respectively. In each year the rate class allocation percentage totals for each program may not add up to 100% in cases were kWh savings are allocated to rate classes billed by kWh and kW demand reductions are allocated to rate classes billed by kW.

Load reductions accounted for in the load forecast

PUC's last cost of service application was filed for the 2013 rate year (EB-2012-0162). The load forecast associated with that application included a CDM adjustment to account for load losses from 2011 – 2013 CDM programs.[8] The LRAMVA Threshold amount was also included in PUC's last cost of service decision to estimate the impact of 2011–2013 CDM programs in 2013 that all parties agreed would be used for the variance calculation with the lost revenue from verified final CDM results.[9] Table 2-b of the OEB LRAMVA work form shows the estimates of load reductions, by rate class that were included at the time of the load forecast. PUC's previous cost of service application was filed for the 2008 rate year (EB-2007-0931). The load forecast associated with that application did not account for load losses from 2011 – 2014 CDM programs.

Overall impact of CDM on load, by rate class

Multiplying the adjusted energy savings or demand reduction reported for PUC for each program by the allocation by rate class provides the impact on load of that CDM program within the appropriate rate class. The sum of the energy savings and demand reductions for all of the programs for each rate class provides the overall impact of CDM on load by rate class. The overall load impact for each calendar year

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[8] The CDM adjustment included the estimated impact of 50% of 2011, 100% of 2012, and 50% of 2013 CDM programs in 2013 and can be found in Settlement Table #5 on Page 19 of 85 of the Proposed Settlement Agreement in the Decision and Rate Order for EB-2012-0162, dated July 4, 2013.

[9] The LRAMVA Threshold amount by rate class can be found in Settlement Table #7 on Page 20 of 85 of the Proposed Settlement Agreement in the Decision and Rate Order for EB-2012-0162, dated July 4, 2013. The text reference to the LRAMVA Threshold amount indicates that it only includes 2012 and 2013 results, but the preceding Table #6 shows that the LRAMVA Threshold amount included the estimated impact of 100% of 2011, 100% of 2012, and 100% of 2013 CDM programs in 2013 and will thus be compared to the verified final results for the same years. Similarly, the headings for Sentinel Lighting and Street Lighting have been reversed.

includes the results for the CDM programs and any adjustments to the results in that year.

The bottom of Table 4a of the OEB LRAMVA work form shows the overall impact of CDM on load by rate class for 2011. The bottom of Table 4b of the OEB LRAMVA work form shows the overall impact of CDM on load by rate class for 2012. The bottom of Table 4c of the OEB LRAMVA work form shows the overall impact of CDM on load by rate class for 2013. The bottom of Table 4d of the OEB LRAMVA work form shows the overall impact of CDM on load by rate class for 2014. The bottom of Tables 5-a and 5-b of the OEB LRAMVA work form shows the overall impact of CDM on load by rate class for 2015 and 2016, respectively.

Distribution rates

The distribution rates that are used to calculate the CDM impact on distributor revenue for each rate class for PUC are shown in Table 3 of the OEB LRAMVA work form. The distribution rates are pro-rated from the rate year to the calendar year, as needed, using the number of months of each rate year in each calendar year in the 2013 to 2016 time period. Table 3-a of the OEB LRAMVA work form shows the pro-rated rates used for each calendar year. 2011-2012 rates were removed, as 2011-2012 LRAMVA was disposed in PUC’s 2013 and 2014 rate cases.

Lost revenues

The lost revenues for each year by rate class for PUC calculated from final CDM program results are shown in Table 1 of the OEB LRAMVA work form. The lost revenue for each year is based on the load impact for each rate class in that year multiplied by the rate for that rate class in that year. The load impact in a given year will include the impact of CDM programs in that year and the persistence of the CDM program impact from previous years in that year.

Table 1 of the OEB LRAMVA work form also shows the lost revenue in each year due to CDM activities accounted for in PUC’s 2013 load forecast. The impact on PUC’s revenue is the variance between what is calculated from final CDM program results and CDM results already accounted for in the load forecast.

Carrying charges

The monthly carrying charges by rate class on PUC’s lost revenue variance are shown in Table 6 of the OEB LRAMVA work form. The carrying charges are reported monthly, from the time the lost revenues resulted, through to April 30, 2018.

Conclusions

The LRAMVA balance at the end of December 2016 for PUC that includes results from 2011 – 2016 CDM programs and adjustments to 2011 to 2015 results in 2013 – 2016 is $463094.51. The total carrying charges on this LRAMVA balance accumulated to April 30, 2018 are $12,582.02. These balances are attributable to individual rate classes according to the following table:

Rate class	LRAMVA	Carrying charges	Total
Residential	$67,238	$188	$67,426
GS < 50 kW	$255,590	$9,166	$264,755
GS 50 to 4,999 kW	$82,129	$2,509	$84,638
Unmetered Scattered Load	-$1,397	-$53	-$1,450
Sentinel Lighting	-$1,051	-$40	-$1,091
Street Lighting	$60,586	$812	$61,398
Total	**$463,095**	**$12,582**	**$475,677**

NOTE: There are no LRAMVA or carrying charge values associated with rate classes not included in this table.

Where negative values are shown, that indicates that the actual reduction in load from CDM programs was less than the LRAMVA amount associated with the load forecast.

providing environmental and energy consulting
to private, public and non-governmental organizations

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APPENDIX 8

PUC Distribution Inc Tax Returns 2012-2016

KPMG LLP
Chartered Accountants
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PRIVATE AND CONFIDENTIAL

Terry Greco
Vice-President
PUC Distribution Inc.
765 Queen Street East
P.o. Box 9000
Sault Ste Marie, ON
P6A 6P2

June 26, 2013

Dear Terry:

Corporate Income Tax Returns

We have prepared the returns of PUC Distribution Inc. (the "Company") for the period ended December 31, 2012 and the related schedule "Corporate Income Tax Filing Instructions". Both the returns and the schedule are attached.

Please review the enclosed filing instructions. All returns must be filed (electronically or in paper format) with the respective taxing authorities by the due date (as set out in the attached filing instructions) if late filing penalties are to be avoided or if losses are carried back to a prior taxation year.

If you have any questions concerning these returns, or if we may be of any further assistance, please do not hesitate to contact us.

Yours truly,

KPMG LLP

Enclosures

PUC Distribution Inc.

Corporate Income Tax Filing Instructions

2012 Taxation Year

We enclose the following income tax returns of PUC Distribution Inc. (the "Company") for the period ended December 31, 2012:

- ☑ T183CORP – *Information Return for Corporations Filing Electronically* (Federal)
- ☑ One copy of the federal and any applicable provincial return(s) for your files
- ☑ Instalment Schedules

We have prepared these returns based on our understanding of the information provided to us by the Company and we recommend that you review the returns to ensure that all of the relevant facts are properly disclosed.When you are satisfied that the returns are in order, one copy of each return should be retained for your records (the copy stamped "Client Copy").

T2 - CORPORATION INCOME TAX RETURN (FEDERAL)

Federal corporate income tax returns can now be electronically transmitted to the Canada Revenue Agency (CRA). In fact, for taxation years ending after 2009, electronic filing of T2 corporate tax returns will be mandatory for most corporations with gross revenues in excess of $1 million. The penalty for non-compliance is $1,000 effective for taxation years that end after 2010. However, the CRA said it would apply the penalty on a gradual basis and that no penalty would be applied for tax years ending before 2012. For tax years ending in 2012, the penalty for non-compliance would be $500.

In order for us to electronically file the Company's corporate income tax return, a signed copy of Form T183CORP - *Information Return for Corporations Filing Electronically* must be returned to us. Please note that we will not electronically file the Company's corporate income tax return until we receive the signed Form T183CORP.

Signature

✍ Form T183CORP – *Information Return for Corporations Filing Electronically*, should be completed and signed.

Mailing

✉ One copy of the signed Form T183CORP should be returned to us in the self-addressed envelope no later than June 30, 2013 in order to have the Company's corporate income tax return filed on or before the due date for filing. Alternatively, you can fax it at **(705) 949-0911**.

Refund

A refund of **$67,882** is claimed and therefore no amount is payable for the **2012** taxation year.

FEDERAL/ONTARIO CORPORATE TAX HARMONIZATION

Ontario corporate income taxes were once again calculated this year using the harmonized federal/Ontario T2 Corporation Income Tax Return. You may recall that, under the harmonization legislation, Ontario tax attributes balances had to be adjusted to their federal balances to determine whether a transitional debit (payable) or credit (receivable) exists as a result of the harmonization.

In the case of PUC Distribution Inc., the harmonization of federal and Ontario corporate income taxes resulted in a transitional balance of $Nil at harmonization. The corporation's nil Ontario transitional balance indicates there was no difference between the various federal and Ontario tax attribute balances at harmonization. As a result, the federal/Ontario corporate tax harmonization has resulted in no tax cost or savings to the corporation.

PROPOSED TAX CHANGES

The corporation's tax return(s) have been prepared taking into account certain proposals to amend the federal and provincial tax statutes which have been publicly announced to date in budgets and other government releases as being applicable to the corporation's current taxation year, even though the proposals may not yet be enacted. If the proposed amendments are not enacted as announced, these tax returns could be reassessed and may result in an underpayment of tax, and possible interest and penalties. If you receive an assessment or reassessment for these tax returns that does not agree with the returns filed, it is important that you notify us so that we can determine if any action needs to be taken.

INSTALMENTS

We have prepared and enclose an estimate of tax instalments as applicable for the Company for the taxation year ending on December 31, 2013. These include instalments for federal income tax and for provincial income and capital taxes. The amounts were computed with reference to the Company's taxable income, taxable capital and income taxes payable for prior years. If during the year it is evident that the taxable income or taxable capital for the current year will be substantially less than for the previous taxation year, your instalments may be recalculated. Overpaid instalments may, in certain circumstances, be transferred to other accounts or applied to other liabilities such as payroll withholdings. Please call your KPMG advisor in order that we may determine what course of action should be taken.

As a consequence of the Ontario/federal corporate tax harmonization, the combined Ontario and federal corporation tax instalment payments for the taxation years ending in 2009 or later must be sent to the CRA.

In order to avoid interest charges, the tax authorities must receive the instalment payments no later than the date indicated on the attached schedule.

NOTICES OF ASSESSMENT

If your Company receives a Notice of Assessment which does not agree with a return as prepared by us, please contact us so that we can determine whether any action should be taken. The Company has only a limited number of days (90 days in the case of federal and Ontario) from the date of mailing of the Assessment in which to object. Failure to respond within the prescribed time limit will cause the Company to lose its right to object to the Assessment.

Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2013-12-31

Business number 86709 6778 RC0001

The following is a list of federal instalments payable for the current taxation year. The last column indicates the instalments payable to Revenue Canada. The instalments are due no later than on the dates indicated, otherwise non-deductible interest will be charged. A cheque or money order should be made payable to the Receiver General. Payment may be made by cheque or money order payable to the Receiver General either to an authorized financial institution or filed with **the appropriate remittance voucher to the following address**:

Canada Revenue Agency
875 Heron Road
Ottawa ON K1A 1B1

Note that you may also be able to pay by telephone or Internet banking. For more information, consult the *Corporation Instalment Guide*.

Monthly instalment workchart

Date	Monthly tax instalments	Refund transferred to instalments	Instalments paid	Cumulative difference	Instalments payable
2013-01-31	33,213				33,213
2013-02-28	33,213				33,213
2013-03-31	33,213				33,213
2013-04-30	33,213				33,213
2013-05-31	33,213				33,213
2013-06-30	33,213				33,213
2013-07-31	33,213				33,213
2013-08-31	33,213				33,213
2013-09-30	33,213				33,213
2013-10-31	33,213				33,213
2013-11-30	33,213				33,213
2013-12-31	33,212				33,212
Totals	398,555				398,555

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

200

055 **Do not use this area**

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

Identification

Business number (BN) **001** 86709 6778 RC0001

Corporation's name
002 PUC Distribution Inc.

Address of head office
Has this address changed since the last time we were notified? . . . . **010** 1 Yes ☐ 2 No ☒
(If **yes**, complete lines 011 to 018.)
011 765 Queen Street East
012 P.o. Box 9000
City **015** Sault Ste Marie
Province, territory, or state **016** ON
Country (other than Canada) **017**
Postal code/Zip code **018** P6A 6P2

Mailing address (if different from head office address)
Has this address changed since the last time we were notified? . . . . **020** 1 Yes ☐ 2 No ☒
(If **yes**, complete lines 021 to 028.)
021 c/o
022
023
City **025**
Province, territory, or state **026**
Country (other than Canada) **027**
Postal code/Zip code **028**

Location of books and records
Has the location of books and records changed since the last time we were notified? . . . . **030** 1 Yes ☐ 2 No ☒
(If **yes**, complete lines 031 to 038.)
031 765 Queen Street E
032
City **035** Sault Ste. Marie
Province,territory, or state **036** ON
Country (other than Canada) **037**
Postal code/Zip code **038** P6A 6P2

040 **Type of corporation at the end of the tax year**
1 ☐ Canadian-controlled private corporation (CCPC)
2 ☐ Other private corporation
3 ☐ Public corporation
4 ☐ Corporation controlled by a public corporation
5 ☒ Other corporation (specify, below) Electrity Act

If the type of corporation changed during the tax year, provide the effective date of the change . . . . **043** ________ YYYY MM DD

To which tax year does this return apply?
Tax year start **060** 2012-01-01 YYYY MM DD
Tax year-end **061** 2012-12-31 YYYY MM DD

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . **063** 1 Yes ☐ 2 No ☒

If yes, provide the date control was acquired . . . . **065** ________ YYYY MM DD

Is the date on line 061 a deemed tax year-end according to:
subparagraph 88(2)(a)(iv)? . . . . **064** 1 Yes ☐ 2 No ☒
subsection 249(3.1)? . . . . **066** 1 Yes ☐ 2 No ☒

Is the corporation a professional corporation that is a member of a partnership? . . . . **067** 1 Yes ☐ 2 No ☒

Is this the first year of filing after:
Incorporation? . . . . **070** 1 Yes ☐ 2 No ☒
Amalgamation? . . . . **071** 1 Yes ☐ 2 No ☒
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . **072** 1 Yes ☐ 2 No ☒
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . **076** 1 Yes ☐ 2 No ☒

Is this the final return up to dissolution? . . . . **078** 1 Yes ☐ 2 No ☒

If an election was made under section 261, state the functional currency used . . . . **079** ________

Is the corporation a resident of Canada?
080 1 Yes ☒ 2 No ☐ If no, give the country of residence on line 081 and complete and attach Schedule 97.
081 ________

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . **082** 1 Yes ☐ 2 No ☒
If yes, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
1 ☐ Exempt under paragraph 149(1)(e) or (l)
2 ☐ Exempt under paragraph 149(1)(j)
3 ☐ Exempt under paragraph 149(1)(t)
4 ☐ Exempt under other paragraphs of section 149

Do not use this area
095 ________ **096** ________

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.

Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	**Schedule**
Is the corporation related to any other corporations?	150	☒	9
Is the corporation an associated CCPC?	160	☒	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161	☐	49
Does the corporation have any non-resident shareholders who own voting shares?	151	☐	19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162	☐	11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163	☐	44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164	☐	14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165	☐	15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166	☐	T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	167	☐	T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168	☐	22
Did the corporation have any foreign affiliates during the year?	169	☐	25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170	☐	29
Has the corporation had any non-arm's length transactions with a non-resident?	171	☐	T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	☒	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172	☐	———
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	☒	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202	☐	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	☐	3
Is the corporation claiming any type of losses?	204	☐	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	☒	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206	☒	6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	207	☒	7
Does the corporation have any property that is eligible for capital cost allowance?	208	☒	8
Does the corporation have any property that is eligible capital property?	210	☒	10
Does the corporation have any resource-related deductions?	212	☐	12
Is the corporation claiming deductible reserves (other than transitional reserves under section 34.2)?	213	☐	13
Is the corporation claiming a patronage dividend deduction?	216	☐	16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217	☐	17
Is the corporation an investment corporation or a mutual fund corporation?	218	☐	18
Is the corporation carrying on business in Canada as a non-resident corporation?	220	☐	20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221	☐	21
Does the corporation have any Canadian manufacturing and processing profits?	227	☐	27
Is the corporation claiming an investment tax credit?	231	☐	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232	☐	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	☒	———
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	☒	———
Is the corporation claiming a surtax credit?	237	☐	37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238	☐	38
Is the corporation claiming a Part I tax credit?	242	☐	42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243	☐	43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244	☐	45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249	☐	46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250	☐	39
Is the corporation claiming a Canadian film or video production tax credit refund?	253	☐	T1131
Is the corporation claiming a film or video production services tax credit refund?	254	☐	T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255	☐	92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	**256**	☐	T1134
Did the corporation have any controlled foreign affiliates?	**258**	☐	T1134
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	**259**	☐	T1135
Did the corporation transfer or loan property to a non-resident trust?	**260**	☐	T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	**261**	☐	T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	**262**	☐	T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	**263**	☐	T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	**264**	☐	T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	**265**	☐	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	**266**	☐	T2002
Has the corporation revoked any previous election made under subsection 89(11)?	**267**	☐	T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	**268**	☐	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	**269**	☐	54

Additional information

Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	**270**	1 Yes ☐	2 No ☒
Is the corporation inactive?	**280**	1 Yes ☐	2 No ☒

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electrical distributor	**285**	100.000 %
286		**287**	%
288		**289**	%

Did the corporation immigrate to Canada during the tax year?	**291**	1 Yes ☐	2 No ☒
Did the corporation emigrate from Canada during the tax year?	**292**	1 Yes ☐	2 No ☒
Do you want to be considered as a quarterly instalment remitter if you are eligible?	**293**	1 Yes ☐	2 No ☐
If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible	**294**	YYYY MM DD	
If the corporation's major business activity is construction, did you have any subcontractors during the tax year?	**295**	1 Yes ☐	2 No ☐

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.			**300**	1,598,019 A
Deduct: Charitable donations from Schedule 2	**311**			
Gifts to Canada, a province, or a territory from Schedule 2	**312**			
Cultural gifts from Schedule 2	**313**			
Ecological gifts from Schedule 2	**314**			
Gifts of medicine from Schedule 2	**315**			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	**320**			
Part VI.1 tax deduction*	**325**			
Non-capital losses of previous tax years from Schedule 4	**331**			
Net capital losses of previous tax years from Schedule 4	**332**			
Restricted farm losses of previous tax years from Schedule 4	**333**			
Farm losses of previous tax years from Schedule 4	**334**			
Limited partnership losses of previous tax years from Schedule 4	**335**			
Taxable capital gains or taxable dividends allocated from a central credit union	**340**			
Prospector's and grubstaker's shares	**350**			
Subtotal			▶	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")				1,598,019 C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions			**355**	D
Taxable income (amount C **plus** amount D)			**360**	1,598,019
Income exempt under paragraph 149(1)(t)			**370**	
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)				1,598,019 Z

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 8. Use 3.2 for tax years ending before 2012.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7	**400**	1,579,257	A
Taxable income from line 360 on page 3, **minus** 100/28* 3.57143 of the amount on line 632** on page 7, **minus** 1/(0.38 - X***) 4 times the amount on line 636**** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax	**405**	1,598,019	B
Business limit (see notes 1 and 2 below)	**410**	356,000	C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 356,000 x **415** ***** 109,344 D / 11,250 = 3,460,130 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0")	**425**		F

Small business deduction

Amount A, B, C, or F, whichever is the least ______ x 17 % =	**430**		G

Enter amount G on line 1 on page 7.

* 10/3 for tax years ending before November 1, 2011. The result of the multiplication by line 632 has to be pro-rated based on the number of days in the tax year that are in each period: before November 1, 2011, and after October 31, 2011.

** Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

*** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

**** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

***** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3*				1,598,019	A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27			B		
Amount QQ from Part 13 of Schedule 27			C		
Personal service business income**	432		D		
Amount used to calculate the credit union deduction from Schedule 17			E		
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least			F		
Aggregate investment income from line 440 on page 6***			G		
Total of amounts B to G			▶		H
Amount A **minus** amount H (if negative, enter "0")				1,598,019	I

Amount I	1,598,019	x	Number of days in the tax year before January 1, 2011 Number of days in the tax year	 366	x	10 %	=		J
Amount I	1,598,019	x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 Number of days in the tax year	 366	x	11.5 %	=		K
Amount I	1,598,019	x	Number of days in the tax year after December 31, 2011 Number of days in the tax year	366 366	x	13 %	=	207,742	L

General tax reduction for Canadian-controlled private corporations – Total of amounts J to L Enter amount M on line 638 on page 7.	207,742	M

* For tax years ending after October 31, 2011, line 360 or amount Z, whichever applies.

** For tax years beginning after October 31, 2011.

*** Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)					N
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27			O		
Amount QQ from Part 13 of Schedule 27			P		
Personal service business income*	434		Q		
Amount used to calculate the credit union deduction from Schedule 17			R		
Total of amounts O to R			▶		S
Amount N **minus** amount S (if negative, enter "0")					T

Amount T		x	Number of days in the tax year before January 1, 2011 Number of days in the tax year	 366	x	10 %	=		U
Amount T		x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 Number of days in the tax year	 366	x	11.5 %	=		V
Amount T		x	Number of days in the tax year after December 31, 2011 Number of days in the tax year	366 366	x	13 %	=		W

General tax reduction – Total of amounts U to W Enter amount X on line 639 on page 7.		X

* For tax years beginning after October 31, 2011.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 . . . . **440** ______ x 26 2 / 3 % = ... ______ A

Foreign non-business income tax credit from line 632 on page 7 . . . . ______

Deduct:

Foreign investment income from Schedule 7 . . . . **445** ______ x 9 1 / 3 % = ______

(if negative, enter "0") ______ ▶ ______ B

Amount A **minus** amount B (if negative, enter "0") . . . . ______ C

Taxable income from line 360 on page 3 . . . . ______

Deduct:

Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . ______

Foreign non-business income tax credit from line 632 on page 7 . . . ______ x 25/9* 100 / 35 = ______

Foreign business income tax credit from line 636 on page 7 . . . . ______ x 1(0.38 - X**) / 4 = ______

______ ▶ ______

x 26 2 / 3 % = ______ D

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8) . . . . ______ E

Refundable portion of Part I tax – Amount C, D, or E, whichever is the least . . . . **450** ______ F

* 100/35 for tax years beginning after October 31, 2011.

** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year . . . . **460** ______

Deduct: Dividend refund for the previous tax year . . . . **465** ______

______ ▶ ______ G

Add the total of:

Refundable portion of Part I tax from line 450 above . . . . ______

Total Part IV tax payable from Schedule 3 . . . . ______

Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation . . . . **480** ______

______ ▶ ______ H

Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H . . . . **485** ______

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3 . . . . ______ x 1 / 3 ______ I

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . ______ J

Dividend refund – Amount I or J, whichever is less (enter this amount on line 784 on page 8) . . . . ______

Part I tax

Base amount of Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 %	550	607,247	A
Recapture of investment tax credit from Schedule 31	602		B

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6			i
Taxable income from line 360 on page 3			
Deduct:			
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least			
Net amount		▶	ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii	604		C
Subtotal (**add** amounts A to C)		607,247	D

Deduct:

Small business deduction from line 430 on page 4			1		
Federal tax abatement	608	159,802			
Manufacturing and processing profits deduction from Schedule 27	616				
Investment corporation deduction	620				
Taxed capital gains **624**					
Additional deduction – credit unions from Schedule 17	628				
Federal foreign non-business income tax credit from Schedule 21	632				
Federal foreign business income tax credit from Schedule 21	636				
General tax reduction for CCPCs from amount M on page 5	638	207,742			
General tax reduction from amount X on page 5	639				
Federal logging tax credit from Schedule 21	640				
Federal qualifying environmental trust tax credit	648				
Investment tax credit from Schedule 31	652				
Subtotal		367,544	▶	367,544	E
Part I tax payable – Amount D **minus** amount E				239,703	F

Enter amount F on line 700 on page 8.

Summary of tax and credits

Federal tax

Part I tax payable from page 7			700	239,703
Part II surtax payable from Schedule 46			708	
Part III.1 tax payable from Schedule 55			710	
Part IV tax payable from Schedule 3			712	
Part IV.1 tax payable from Schedule 43			716	
Part VI tax payable from Schedule 38			720	
Part VI.1 tax payable from Schedule 43			724	
Part XIII.1 tax payable from Schedule 92			727	
Part XIV tax payable from Schedule 20			728	
			Total federal tax	239,703

Add provincial or territorial tax:

Provincial or territorial jurisdiction . . . 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	158,852		
Provincial tax on large corporations (Nova Scotia Schedule 342)	765			
(The Nova Scotia tax on large corporations is eliminated effective July 2012.)		158,852 ▶		158,852
			Total tax payable 770	398,555 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780			
Dividend refund from page 6	784			
Federal capital gains refund from Schedule 18	788			
Federal qualifying environmental trust tax credit refund	792			
Canadian film or video production tax credit refund (Form T1131)	796			
Film or video production services tax credit refund (Form T1177)	797			
Tax withheld at source	800			
Total payments on which tax has been withheld 801				
Provincial and territorial capital gains refund from Schedule 18	808			
Provincial and territorial refundable tax credits from Schedule 5	812			
Tax instalments paid	840	466,437		
Total credits	890	466,437	▶	466,437 B

Refund code 894 1   Overpayment 67,882 ◀   Balance (amount A **minus** amount B) -67,882

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid . . . .
Enclosed payment 898

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 ______ Branch number

914 ______ Institution number 918 ______ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? . . . 896 1 Yes ☐ 2 No ☒

If this return was prepared by a tax preparer for a fee, provide their EFILE number . . . 920 A5001

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Certification

I, 950 Greco (Last name (print)) 951 Terry (First name (print)) 954 Vice-President (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2013-06-26 Date (yyyy/mm/dd) ______ Signature of the authorized signing officer of the corporation 956 (705) 759-6566 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . 957 1 Yes ☒ 2 No ☐

958 ______ Name (print) 959 ______ Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

Privacy Act, Personal Information Bank number CRA PPU 047

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SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2012-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	18,064,907	23,757,779
	Total tangible capital assets	2008	+	128,112,006	96,776,288
	Total accumulated amortization of tangible capital assets	2009	–	51,975,297	48,231,553
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	2,300,000	6,463,372
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	96,501,616	78,765,886
	Liabilities				
	Total current liabilities	3139	+	15,400,286	17,950,884
	Total long-term liabilities	3450	+	56,749,532	38,169,549
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	72,149,818	56,120,433
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	24,351,798	22,645,453
	Total liabilities and shareholder equity	3640	=	96,501,616	78,765,886
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	4,289,691	2,583,346

* Generic item

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SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2012-12-31

Income statement information

Description **GIFI**

Operating name . . . . **0001** ____
Description of the operation . . . . . **0002** ____
Sequence number **0003** 01

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+	78,026,469	74,564,085
	Cost of sales	8518	–	60,573,316	60,116,743
	Gross profit/loss	8519	=	17,453,153	14,447,342
	Cost of sales	8518	+	60,573,316	60,116,743
	Total operating expenses	9367	+	17,388,822	14,092,898
	Total expenses (mandatory field)	9368	=	77,962,138	74,209,641
	Total revenue (mandatory field)	8299	+	80,091,958	76,732,947
	Total expenses (mandatory field)	9368	–	77,962,138	74,209,641
	Net non-farming income	9369	=	2,129,820	2,523,306
	Farming income statement information				
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	2,129,820	2,523,306
	Total other comprehensive income	9998	=		
	Extraordinary items and income (linked to Schedule 140)				
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–	423,475	466,500
	Future (deferred) income tax provision	9995	–		
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	1,706,345	2,056,806

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Schedule 141

Notes checklist

Corporation's name	Business number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2012-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the **accountant**) who prepared or reported on the financial statements. If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and Guide T4012, *T2 Corporation – Income Tax Guide.*
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? . . . . **095** 1 Yes ☒ 2 No ☐

Is the accountant connected* with the corporation? . . . . **097** 1 Yes ☐ 2 No ☒

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note

If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you **do have** to complete Part 4, as applicable.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: **198**

Completed an auditor's report . . . . 1 ☒

Completed a review engagement report . . . . 2 ☐

Conducted a compilation engagement . . . . 3 ☐

Part 3 – Reservations

If you selected option **1** or **2** under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . . **099** 1 Yes ☐ 2 No ☒

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: **110**

Prepared the tax return (financial statements prepared by client) . . . . 1 ☐

Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . . 2 ☐

Were notes to the financial statements prepared? . . . . **101** 1 Yes ☒ 2 No ☐

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes? . . . . **104** 1 Yes ☐ 2 No ☒

Is re-evaluation of asset information mentioned in the notes? . . . . **105** 1 Yes ☐ 2 No ☒

Is contingent liability information mentioned in the notes? . . . . **106** 1 Yes ☐ 2 No ☒

Is information regarding commitments mentioned in the notes? . . . . **107** 1 Yes ☐ 2 No ☒

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . **108** 1 Yes ☐ 2 No ☒

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . **200** 1 Yes ☐ 2 No ☒

If **yes**, enter the amount recognized:

		In net income Increase (decrease)		**In OCI** Increase (decrease)
Property, plant, and equipment	**210**		**211**	
Intangible assets	**215**		**216**	
Investment property	**220**			
Biological assets	**225**			
Financial instruments	**230**		**231**	
Other	**235**		**236**	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? . . . . **250** 1 Yes ☐ 2 No ☒

Did the corporation apply hedge accounting during the tax year? . . . . **255** 1 Yes ☐ 2 No ☒

Did the corporation discontinue hedge accounting during the tax year? . . . . **260** 1 Yes ☐ 2 No ☒

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . **265** 1 Yes ☐ 2 No ☒

If **yes**, you have to maintain a separate reconciliation.

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Net Income (Loss) for Income Tax Purposes

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2012-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide.*
- All legislative references are to the *Income Tax Act.*

Amount calculated on line 9999 from Schedule 125			1,706,345	A
Add:				
Provision for income taxes – current	101	423,475		
Amortization of tangible assets	104	4,320,787		
Taxable capital gains from Schedule 6	113	18,762		
Subtotal of additions		4,763,024 ▶	4,763,024	
Other additions:				
Miscellaneous other additions:				
604				
Total	294			
Subtotal of other additions	199	0 ▶	0	
Total additions	500	4,763,024 ▶	4,763,024	B
Amount A **plus** amount B			6,469,369	
Deduct:				
Gain on disposal of assets per financial statements	401	22,253		
Capital cost allowance from Schedule 8	403	4,597,224		
Cumulative eligible capital deduction from Schedule 10	405	251,873		
Subtotal of deductions		4,871,350 ▶	4,871,350	
Other deductions:				
Miscellaneous other deductions:				
704				
Total	394			
Subtotal of other deductions	499	0 ▶	0	
Total deductions	510	4,871,350 ▶	4,871,350	
Net income (loss) for income tax purposes – enter on line 300 of the T2 return			1,598,019	

T2 SCH 1 E (12)

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Schedule 5

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2012-12-31

- Use this schedule if, during the tax year, the corporation:
  - – had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - – is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - – has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations*.
- For more information, see the *T2 Corporation – Income Tax Guide.*
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 ________ Enter the Regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2*** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes ☐	103		143		
Newfoundland and Labrador offshore	004 1 Yes ☐	104		144		
Prince Edward Island	005 1 Yes ☐	105		145		
Nova Scotia	007 1 Yes ☐	107		147		
Nova Scotia offshore	008 1 Yes ☐	108		148		
New Brunswick	009 1 Yes ☐	109		149		
Quebec	011 1 Yes ☐	111		151		
Ontario	013 1 Yes ☐	113		153		
Manitoba	015 1 Yes ☐	115		155		
Saskatchewan	017 1 Yes ☐	117		157		
Alberta	019 1 Yes ☐	119		159		
British Columbia	021 1 Yes ☐	121		161		
Yukon	023 1 Yes ☐	123		163		
Northwest Territories	025 1 Yes ☐	125		165		
Nunavut	026 1 Yes ☐	126		166		
Outside Canada	027 1 Yes ☐	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).

** If the corporation has income or loss from an international banking centre: the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act*.

*** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
1,598,019		1,598,019	158,852

Ontario basic income tax (from Schedule 500)	270	183,772		
Deduct: Ontario small business deduction (from Schedule 500)	402	24,920		
Subtotal		158,852	158,852	A6
Add:				
Ontario additional tax re Crown royalties (from Schedule 504)	274			
Ontario transitional tax debits (from Schedule 506)	276			
Recapture of Ontario research and development tax credit (from Schedule 508)	277			
Subtotal				B6
Subtotal (amount A6 **plus** amount B6)			158,852	C6
Deduct:				
Ontario resource tax credit (from Schedule 504)	404			
Ontario tax credit for manufacturing and processing (from Schedule 502)	406			
Ontario foreign tax credit (from Schedule 21)	408			
Ontario credit union tax reduction (from Schedule 500)	410			
Ontario transitional tax credits (from Schedule 506)	414			
Ontario political contributions tax credit (from Schedule 525)	415			
Subtotal				D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")			158,852	E6
Deduct: Ontario research and development tax credit (from Schedule 508)	416			
Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0")			158,852	F6
Deduct: Ontario corporate minimum tax credit (from Schedule 510)	418			
Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0")			158,852	G6
Add:				
Ontario corporate minimum tax (from Schedule 510)	278			
Ontario special additional tax on life insurance corporations (from Schedule 512)	280			
Subtotal				H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)			158,852	I6
Deduct:				
Ontario qualifying environmental trust tax credit	450			
Ontario co-operative education tax credit (from Schedule 550)	452			
Ontario apprenticeship training tax credit (from Schedule 552)	454			
Ontario computer animation and special effects tax credit (from Schedule 554)	456			
Ontario film and television tax credit (from Schedule 556)	458			
Ontario production services tax credit (from Schedule 558)	460			
Ontario interactive digital media tax credit (from Schedule 560)	462			
Ontario sound recording tax credit (from Schedule 562)	464			
Ontario book publishing tax credit (from Schedule 564)	466			
Ontario innovation tax credit (from Schedule 566)	468			
Ontario business-research institute tax credit (from Schedule 568)	470			
Other Ontario tax credits				
Subtotal				J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255.	290		158,852	K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits	255	158,852

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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SCHEDULE 6

SUMMARY OF DISPOSITIONS OF CAPITAL PROPERTY

Name of corporation	Business Number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2012-12-31

- For use by corporations that have disposed of capital property or claimed an allowable business investment loss (ABIL), or both, in the tax year.
- Use this schedule to make a designation under paragraph 111(4)(e) of the federal *Income Tax Act* if control of the corporation has been acquired by a person or a group of persons.
- For more information, see the section called "Schedule 6, Summary of Dispositions of Capital Property" in the *T2 Corporation – Income Tax Guide*.

Designation under paragraph 111(4)(e) of the *Income Tax Act*

Are any dispositions shown on this schedule related to deemed dispositions designated under paragraph 111(4)(e)?

050 1 Yes ☐ 2 No ☒ If **yes**, attach a statement specifying which properties are subject to such a designation.

Part 1 – Shares

No. of shares 100	Name of corporation 105	Class of shares 106	Date of acquisition YYYY/MM/DD 110	Proceeds of disposition 120	Adjusted cost base 130	Outlays and expenses (dispositions) 140	Gain (or loss) (column 120 **minus** cols. 130 and 140) 150	Foreign source
			Totals					

Total adjustment under subsection 112(3) of the Act to all losses identified in Part 1 . . . . **160** ________

Actual gain or loss from the disposition of shares (total of line 150 **plus** line 160) . . . . ________ A

Part 2 – Real estate (Do not include losses on depreciable property.)

	Municipal address 1 = Address 1 2 = Address 2 3 = City 4 = Province, Country, Postal Code and Zip Code or Foreign Postal Code 200	Date of acquisition YYYY/MM/DD 210	Proceeds of disposition 220	Adjusted cost base 230	Outlays and expenses (dispositions) 240	Gain (or loss) (column 220 **minus** cols. 230 and 240) 250	Foreign source	
1			39,150	607	1,020	37,523		
		Totals	39,150	607	1,020	37,523		B

Part 3 – Bonds

Face value 300	Maturity date 305	Name of issuer 307	Date of acquisition YYYY/MM/DD 310	Proceeds of disposition 320	Adjusted cost base 330	Outlays and expenses (dispositions) 340	Gain (or loss) (column 320 **minus** cols. 330 and 340) 350	Foreign source
			Totals					C

Part 4 – Other properties (Do not include losses on depreciable property.)

Description 400	Date of acquisition YYYY/MM/DD 410	Proceeds of disposition 420	Adjusted cost base 430	Outlays and expenses (dispositions) 440	Gain (or loss) (column 420 **minus** cols. 430 and 440) 450	Foreign source
	Totals					D

Note:
Other property includes capital debts established as bad debts, as well as amounts that arise from foreign currency transactions.

Part 5 – Personal-use property (Do not include listed personal property.)

Description 500	Date of acquisition YYYY/MM/DD 510	Proceeds of disposition 520	Adjusted cost base 530	Outlays and expenses (dispositions) 540	Gain only (column 520 minus cols. 530 and 540) 550	Foreign source
						☐
	Totals					E

Note:
You cannot deduct losses on dispositions of personal-use property (other than listed personal property) from your income.

Part 6 – Listed personal property

Description 600	Date of acquisition YYYY/MM/DD 610	Proceeds of disposition 620	Adjusted cost base 630	Outlays and expenses (dispositions) 640	Gain (or loss) (column 620 minus cols. 630 and 640) 650	Foreign source
						☐
	Totals					

Subtract: Unapplied listed personal property losses from other years **655** ______

Net gains (or losses) ______ F

Note:
Net listed personal property losses can only be applied against listed personal property gains.
The amount on line 655 is from line 530 in Part 5 of Schedule 4, *Corporation Loss Continuity and Application*.

Part 7 – Determining allowable business investment losses

Property qualifying for and resulting in an allowable business investment loss

Name of small business corporation 900	Shares, enter 1; debt, enter 2 905	Date of acquisition YYYY/MM/DD 910	Proceeds of disposition 920	Adjusted cost base 930	Outlays and expenses (dispositions) 940	Loss only (column 920 minus cols. 930 and 940) 950	Foreign source
							☐
		Totals					G

ABILs . . . . Amount G ______ x 50.0000 % = ______ H
(enter amount H on line 406 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*)

Note:
Properties listed in Part 7 should not be included in any other parts of Schedule 6.

Part 8 – Determining capital gains or losses

Total of amounts A to F (do not include F if the amount is a loss)		37,523	I
Add:			Foreign source
Capital gains dividend received in the year	875		J ☐
Capital gains reserve opening balance (from Schedule 13)	880		K
Subtotal (**add** amounts I, J, and K)		37,523	L
Deduct:			
Capital gains reserve closing balance (from Schedule 13)	885		M
Capital gains or losses, excluding ABILs (amount L **minus** amount M)	890	37,523	

Part 9 – Determining taxable capital gains and total capital losses

Capital gains or losses, excluding ABILs (amount from line 890 above) . . . . 37,523 N

Deduct the following gains that are included in amount N:

Gain on donation of a share, debt obligation, or right listed on a designated stock exchange and other amounts under paragraph 38(a.1) of the Act

realized before May 2, 2006 . . . . ______ x 50.0000 % = ______ O Foreign source ☐

realized after May 1, 2006 . . . . ______ P Foreign source ☐

Subtotal (O **plus** P) **895** ______

Gain on donation of ecologically sensitive land

realized before May 2, 2006 . . . . ______ x 50.0000 % = ______ Q Foreign source ☐

realized after May 1, 2006 . . . . ______ R Foreign source ☐

Subtotal (Q **plus** R) **896** ______

Exempt portion of the gain on the donation of securities arising from the exchange of a partnership interest under paragraph 38(*a.3*) . . . . ______ R-2 Foreign source ☐

Total (line 895 **plus** line 896 **plus** line R-2) ______ S

Total capital gains or losses (amount N **minus** amount S) 37,523 T

Note:
If amount T is a loss, enter it on line 210 of Schedule 4.

Taxable capital gains: If amount T is a gain, enter it on this line and **multiply** . . . 37,523 x 50.0000 % = 18,762 U
(Enter amount U on line 113 of Schedule 1.)

T2 SCH 6 E (10)

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Schedule 7

Aggregate Investment Income and Active Business Income

Corporation's name	Business Number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2012-12-31

- This schedule is for the use of Canadian-controlled private corporations to calculate:
  - aggregate investment income and foreign investment income for the purpose of determining the refundable portion of Part I tax, as defined in subsection 129(4) of the *Income Tax Act;*
  - specified partnership income for members of one or more partnership(s); and
  - income from an active business carried on in Canada for the small business deduction.
- For more information, see the sections called "Small Business Deduction" and "Refundable Portion of Part I Tax" in Guide T4012, *T2 Corporation – Income Tax Guide.*

Part 1 – Aggregate investment income

The aggregate investment income is the aggregate **world** source income.

The eligible portion of taxable capital gains included in income for the year	**002**					18,762	A
Deduct:							
Eligible portion of allowable capital losses for the year (including allowable business investment losses)	**012**				a		
Net capital losses of other years claimed on line 332 on the T2 return	**022**				b		
Amount a **plus** amount b					▶		B
Amount A **minus** amount B (if negative, enter "0")						18,762	C
Total income from property (include income from a specified investment business carried on in Canada other than income from a source outside Canada)	**032**				c		
Deduct:							
Exempt income	**042**		1				
Amounts received from AgriInvest Fund No. 2 that were included in computing the corporation's income for the year	**052**		2				
Taxable dividends deductible (total of Column F on Schedule 3)	**062**		3				
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a)	**072**		4				
Total of amounts 1 to 4			▶		d		
Subtotal (amount c **minus** amount d)					▶		D
Amount C **plus** amount D						18,762	E
Total losses from property (include losses from a specified investment business carried on in Canada other than a loss from a source outside Canada)	**082**						F
Amount E **minus** amount F (if negative, enter "0")	**092**					18,762	G

Enter amount G on line 440 of the T2 return.

Part 2A – Canadian investment income calculation

Eligible portion of taxable capital gains included in the income for the year before taking into account the capital gains reserve (federal) of Schedule 13	18,762	1.1		
Reserve's eligible portion (addition/deduction)		1.2		
The eligible portion of taxable capital gains included in income for the year after taking into account the capital gains reserve (federal) of Schedule 13 (total of amounts 1.1 and 1.2)	18,762	▶	18,762	1a
Deduct:				
Eligible portion of allowable capital losses for the year (including allowable business investment losses)		2a		
Net capital losses of other years claimed on line 332 on the T2 return		3a		
Total of amounts 2a and 3a		▶		4a
Amount 1a **minus** amount 4a (if negative, enter "0")			18,762	5a

Part 2A – Canadian investment income calculation (continued)

Taxable dividends		6.1			
Real estate rental properties (under regulation 1100(11))		6.2			
Other property income		6.3			
Total income from property from a source **Canadian**		▶			6a
Deduct:					
Exempt income		7a			
Amounts received from AgriInvest Fund No. 2 that were included in computing the corporation's income for the year		8a			
Taxable dividends deductible (total of Column F on Schedule 3)		9a			
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a)		10a			
Total of amounts 7a to 10a		▶			11a
Amount 6a **minus** amount 11a					12a
Amount 5a **plus** amount 12a				18,762	13a
Losses from rental properties (under regulation 1100(11))		14.1			
Other losses from property		14.2			
Total losses from property from a source **Canadian**		▶			14a
Amount 13a **minus** amount 14a (if negative, enter "0")				18,762	15a

Part 2 – Foreign investment income

The foreign investment income is all income from sources **outside of Canada**.

Eligible portion of taxable capital gains included in the income for the year before taking into account the capital gains reserve (federal) of Schedule 13						H1			
Reserve's eligible portion (addition/deduction)						H2			
The eligible portion of taxable capital gains included in income for the year after taking into account the capital gains reserve (federal) of Schedule 13 (total of amounts H1 and H2)						▶	**001**		H
Eligible portion of allowable capital losses for the year (including allowable business investment losses)							**009**		I
Subtotal (amount H **minus** amount I) (if negative, enter "0")									J
Taxable dividends			e1						
Real estate rental properties (under regulation 1100(11))			e2						
Other property income			e3						
Total income from property from a source **outside Canada**			▶	**019**		e			
Deduct:									
Exempt income	**029**		5						
Taxable dividends deductible (total of Column F on Schedule 3)	**049**		6						
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a)	**059**		7						
Total of amounts 5 to 7			▶			f			
Subtotal (amount e **minus** amount f)						▶			K
Amount J **plus** amount K									L
Losses from rental properties (under regulation 1100(11))						M1			
Other losses from property						M2			
Total losses from property from a source **outside Canada**						▶	**069**		M
Amount L **minus** amount M (if negative, enter "0") (enter amount N on line 445 of the T2 return)							**079**		N

Net taxable dividends	**Canadian**	**Foreign**	**Total**
Taxable dividends deducted per schedule 3			
Less: Expenses related to such dividends			
Total expenses			
Net taxable dividends			

Part 3 – Specified partnership income

A	B	C
Partnership name 200	Total income (loss) of partnership from an active business 300	Corporation's share of amount in column B 310

D	E	F	G	H	I
Adjustments (add or deduct the prorated amounts calculated under section 34.2* and deduct expenses incurred by the corporation to earn partnership income) 315	Corporation's income (loss) of the partnership (column C **plus** column D) 320	Number of days in the partnership's fiscal period 325	Prorated business limit (column C ÷ column B) x [$500,000 x (column F ÷ 365)] (if column C is negative, enter "0")** 330	Column E **minus** column G (if negative, enter "0")	Lesser of columns E and G (if column E is negative, enter "0") 340
Total	350		Total	385	360

Corporation's losses for the year from an active business carried on in Canada (other than as a member of a partnership) – enter as a positive amount . . . . 370 ____________ g

Specified partnership loss of the corporation for the year – enter as a positive amount (total of all negative amounts in column E) . . . . 380 ____________ h

Subtotal (amount g **plus** amount h) ____________ i

Amount at line 385 or amount i, whichever is less . . . . 390 ____________ O

Specified partnership income (line 360 **plus** amount O) . . . . 400 ____________ P

Enter amount P at line T in Part 4.

* In general, amounts included or deducted under subsections 34.2(2), 34.2(3), 34.2(4), 34.2(11), and 34.2(12) are deemed to have the **same character** and be in the **same proportions** as the partnership income to which they relate. For example, if a corporation receives $100,000 of partnership income for the partnership's fiscal period ending in its tax year, and that income is made up of $40,000 of active business income, $30,000 of income from property, and $30,000 as a taxable capital gain, the corporation's adjusted stub period accrual (ASPA) in respect of the partnership would be 40% active business income, 30% property income, and 30% taxable capital gains. Add or deduct **only the proportion** of the following amounts that is deemed under subsection 34.2(5) to be **active business income**:

add:

- the ASPA under subsection 34.2(2) (column 4 of Schedule 73);
- the income inclusion for a new corporate member of a partnership under subsection 34.2(3) (column 6 of Schedule 73);
- the previous-year transitional reserve under subsection 34.2(12) (column 12 of Schedule 73);

deduct:

- the previous-year ASPA under subsection 34.2(4) (column 5 of Schedule 73);
- the previous-year income inclusion for a new corporate member of a partnership under subsection 34.2(4) (column 7 of Schedule 73); and
- the current-year transitional reserve under subsection 34.2(11) (column 11 of Schedule 73).

** When a partnership carries on more than one business, one of which generates income and another of which realizes a loss, the loss is not netted against the partnership's income for the purpose of calculating the prorated business limit in column G. Enter on line h the total of all loss from column E.

Part 4 – Determination of partnership income

Corporation's share of partnership income from active businesses carried on in Canada after deducting related expenses – from line 350 in Part 3 (if the net amount is negative, enter "0" on line U)			Q
Specified partnership loss (from amount h in Part 3)			R
Subtotal (amount Q **plus** amount R)			S
Deduct:			
Specified partnership income (from amount P in Part 3)			T
Partnership income (amount S **minus** amount T) (enter on line p in Part 5)	450		U

Part 5 – Income from active business carried on in Canada

Net income for income tax purposes from line 300 of the T2 return		1,598,019	j		
Plus:					
Allowable business investment loss from line 406 of Schedule 1			k		
Subtotal (amount j **plus** amount k)		1,598,019	▶	1,598,019	V
Deduct:					
Foreign business income after deducting related expenses*	500		l		
Taxable capital gains **minus** allowable capital loss (amount A **minus** amount a* in Part 1)**		18,762	m		
Net property income [amount c **minus** (amounts 1, 2, and F* in Part 1)]			n		
Personal services business income and other income after deducting related expenses*	520		o		
Total of amounts l to o		18,762	▶	18,762	W
Net amount (amount V **minus** amount W)				1,579,257	X
Deduct:					
Partnership income (amount U in Part 4)			p		
Income allocated to the corporation under subsection 96(1.1)			q		
Subtotal (amount p **plus** amount q)			▶		Y
Income from active business carried on in Canada (amount X **minus** amount Y) (enter amount Z on line 400 of the T2 return - if negative, enter "0")				1,579,257	Z

* If negative, enter amount in brackets, and **add** instead of **subtracting**.

** This amount may only be negative to the extent of any allowable business investment losses.

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2012-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes ☐ 2 No ☒

	1 Class number (See Note) 200	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Net adjustments** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % **** 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ***** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
1.	1		28,330,725			0		28,330,725	4	0	0	1,133,229	27,197,496
2.	47		23,404,225	6,493,082		0	3,246,541	26,650,766	8	0	0	2,132,061	27,765,246
3.	8	Smart meters	3,680,320	882,065		0	441,033	4,121,352	20	0	0	824,270	3,738,115
4.	12	Software	49,334			0		49,334	100	0	0	49,334	
5.	1	New Building		22,916,497		0	11,458,249	11,458,248	4	0	0	458,330	22,458,167
		Totals	55,464,604	30,291,644			15,145,823	70,610,425				4,597,224	81,159,024

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed.
Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** Enter a rate only, if you are using the declining balance method. For any other method (for example the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

T2 SCH 8 (11)

Canada

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2012-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name	Country of residence (other than Canada)	Business number (see note 1)	Relationship code (see note 2)	Number of common shares you own	% of common shares you own	Number of preferred shares you own	% of preferred shares you own	Book value of capital stock
	100	**200**	**300**	**400**	**500**	**550**	**600**	**650**	**700**
1.	PUC Inc		89839 7518 RC0001	1	8,612	100.000			20,062,107
2.	PUC Services Inc		87626 3526 RC0002	3					
3.	PUC TELECOM INC.		88614 1811 RC0001	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

T2 SCH 9 (11)

Canada

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2012-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0")				200	3,598,179	A
Add: Cost of eligible capital property acquired during the taxation year	222					
Other adjustments	226					
Subtotal (line 222 plus line 226)			x 3 / 4 =			B
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002	228		x 1 / 2 =			C
amount B minus amount C (if negative, enter "0")			▶			D
Amount transferred on amalgamation or wind-up of subsidiary				224		E
Subtotal (add amounts A, D, and E)				230	3,598,179	F
Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year	242		G			
The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7)	244		H			
Other adjustments	246		I			
(add amounts G,H, and I)			x 3 / 4 =	248		J
Cumulative eligible capital balance (amount F minus amount J)					3,598,179	K

(if amount K is negative, enter "0" at line M and proceed to Part 2)

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business			249			
amount K	3,598,179					
less amount from line 249						
Current year deduction	3,598,179	x 7.00 % =	250	251,873 *		
(line 249 plus line 250) (enter this amount at line 405 of Schedule 1)				251,873 ▶	251,873	L
Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0")			300		3,346,306	M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)					N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988			**400**	1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)			**401**	2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	**402**	3			
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	**408**	4			
Line 3 minus line 4 (if negative, enter "0")		▶		5	
Total of lines 1, 2 and 5				6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400		7			
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000		8			
Subtotal (line 7 plus line 8)	**409**	▶		9	
Line 6 minus line 9 (if negative, enter "0")				▶	O
Line N minus line O (if negative, enter "0")					P
			Line 5	x 1 / 2 =	Q
Line P minus line Q (if negative, enter "0")					R
			Amount R	x 2 / 3 =	S
Amount N or amount O, whichever is less					T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)				**410**	

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SCHEDULE 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)
2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 – Associated non-CCPC
5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2006	maximum $300,000
2007	$300,001 to $400,000

Calendar year	Acceptable range
2008	maximum $400,000
2009	$400,001 to $500,000

If the calendar year to which this agreement applies is after 2009, ensure that the total at line A does not exceed $500,000.

Allocating the business limit

Date filed (do not use this area) . . . . . . **025** Year Month Day

Enter the calendar year to which the agreement applies . . . . . . **050** Year 2012

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . . **075** 1 Yes ☐ 2 No ☒

	1 Names of associated corporations **100**	2 Business Number of associated corporations **200**	3 Association code **300**	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % **350**	6 Business limit allocated* $ **400**	
1	PUC Distribution Inc.	86709 6778 RC0001	1	500,000	71.2000	356,000	
2	PUC Inc	89839 7518 RC0001	1	500,000	28.8000	144,000	
3	PUC Services Inc	87626 3526 RC0002	1	500,000			
4	PUC TELECOM INC.	88614 1811 RC0001	1	500,000			
				Total	100.0000	500,000	A

Business limit reduction under subsection 125(5.1) of the ITA

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. If the tax year straddles January 1, 2009, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year, if $500,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2012-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

		Provide only one number per shareholder				
	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) **100**	Business Number (If a corporation is not registered, enter "NR") **200**	Social insurance number **300**	Trust number **350**	Percentage common shares **400**	Percentage preferred shares **500**
1	PUC Inc	89839 7518 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

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Schedule 500

Ontario Corporation Tax Calculation

Corporation's name	Business number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2012-12-31

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- All legislative references are to the federal *Income Tax Act* and *Income Tax Regulations.*
- This schedule is a worksheet only. You do not have to file it with your *T2 Corporation Income Tax Return.*

Part 1 – Calculation of Ontario basic rate of tax for the year

Number of days in the tax year before July 1, 2011 / Number of days in the tax year	/ 366	x	12.00 %	=	%	A1
Number of days in the tax year after June 30, 2011 / Number of days in the tax year	366 / 366	x	11.50 %	=	11.50000 %	A2

Ontario basic rate of tax for the year (rate A1 **plus** A2) 11.50000 ▶ 11.50000 % A3

Part 2 – Calculation of Ontario basic income tax

Ontario taxable income *	1,598,019	B
Ontario basic income tax: amount B **multiplied** by Ontario basic rate of tax for the year (rate A3 from Part 1)	183,772	C

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit in addition to Ontario basic income tax, or has Ontario corporate minimum tax or Ontario special additional tax on life insurance corporations payable, enter amount C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Part 3 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

Income from active business carried on in Canada (amount from line 400 of the T2 return)	1,579,257	1
Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return)	1,598,019	2
Federal business limit before the application of subsection 125(5.1) (amount from line 410 of the T2 return)	356,000	3
Enter the least of amounts 1, 2, and 3	356,000	D

Ontario domestic factor: Ontario taxable income * / Taxable income earned in all provinces and territories ** = 1,598,019.00 / 1,598,019 = 1.00000 E

Amount D x factor E 356,000 a

Ontario taxable income (amount B from Part 2) 1,598,019 b

Ontario small business income (lesser of amount a and amount b) 356,000 F

Number of days in the tax year before July 1, 2011 / Number of days in the tax year: ____ / 366 x 7.50 % = ____ % G1

Number of days in the tax year after June 30, 2011 / Number of days in the tax year: 366 / 366 x 7.00 % = 7.00000 % G2

OSBD rate for the year (rate G1 **plus** G2) 7.00000 % G3

Ontario small business deduction: amount F **multiplied** by OSBD rate for the year (rate G3) 24,920 H

Enter amount H on line 402 of Schedule 5.

* Enter amount B from Part 2.

** Includes the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

Part 4 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Ontario adjusted small business income (lesser of amount D and amount b from Part 3) 356,000 I

Enter amount I on line K in Part 5 of this schedule or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Part 5 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

Amount D from Part 3 of Schedule 17 . . . . ______ J

Deduct:

Ontario adjusted small business income (amount I from Part 4) . . . . ______ K

Subtotal (amount J **minus** amount K) (if negative, enter "0") . . . . ______ L

OSBD rate for the year (rate G3 from Part 3) . . . . 7.00000 %

Amount L **multiplied** by the OSBD rate for the year . . . . ______ M

Ontario domestic factor (factor E from Part 3) . . . . 1.00000 N

Ontario credit union tax reduction (amount M **multiplied** by factor N) . . . . ______ O

Enter amount O on line 410 of Schedule 5.

Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2014-12-31

Business number 86709 6778 RC0001

The following is a list of federal instalments payable for the current taxation year. The last column indicates the instalments payable to Revenue Canada. The instalments are due no later than on the dates indicated, otherwise non-deductible interest will be charged. A cheque or money order should be made payable to the Receiver General. Payment may be made by cheque or money order payable to the Receiver General either to an authorized financial institution or filed with **the appropriate remittance voucher to the following address**:

Canada Revenue Agency
875 Heron Road
Ottawa ON K1A 1B1

Note that you may also be able to pay by telephone or Internet banking. For more information, consult the *Corporation Instalment Guide*.

Monthly instalment workchart

Date	Monthly tax instalments	Refund transferred to instalments	Instalments paid	Cumulative difference	Instalments payable
2014-01-31	8,238				8,238
2014-02-28	8,238				8,238
2014-03-31	8,238				8,238
2014-04-30	8,238				8,238
2014-05-31	8,238				8,238
2014-06-30	8,238				8,238
2014-07-31	8,238				8,238
2014-08-31	8,238				8,238
2014-09-30	8,238				8,238
2014-10-31	8,238				8,238
2014-11-30	8,238				8,238
2014-12-31	8,235				8,235
Totals	98,853				98,853

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T2 Corporation Income Tax Return

200

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

055 **Do not use this area**

Identification

Business number (BN) **001** 86709 6778 RC0001

Corporation's name
002 PUC Distribution Inc.

Address of head office
Has this address changed since the last time we were notified? . . . . **010** 1 Yes ☐ 2 No ☒
(If **yes**, complete lines 011 to 018.)
011 500 Second Line East
012
City **015** Sault Ste Marie
Province, territory, or state **016** ON
Country (other than Canada) **017**
Postal code/Zip code **018** P6A 4K1

Mailing address (if different from head office address)
Has this address changed since the last time we were notified? . . . . **020** 1 Yes ☐ 2 No ☒
(If **yes**, complete lines 021 to 028.)
021 c/o
022
023
City **025**
Province, territory, or state **026**
Country (other than Canada) **027**
Postal code/Zip code **028**

Location of books and records
Has the location of books and records changed since the last time we were notified? . . . . **030** 1 Yes ☐ 2 No ☒
(If **yes**, complete lines 031 to 038.)
031 500 Second Line East
032
City **035** Sault Ste Marie
Province,territory, or state **036** ON
Country (other than Canada) **037**
Postal code/Zip code **038** P6A 4K1

040 **Type of corporation at the end of the tax year**
1 ☐ Canadian-controlled private corporation (CCPC)
2 ☐ Other private corporation
3 ☐ Public corporation
4 ☐ Corporation controlled by a public corporation
5 ☒ Other corporation (specify, below)
Electrity Act

If the type of corporation changed during the tax year, provide the effective date of the change **043**
YYYY MM DD

To which tax year does this return apply?
Tax year start **060** 2013-01-01 YYYY MM DD
Tax year-end **061** 2013-12-31 YYYY MM DD

Has there been an acquisition of control to which subsection 249(4) applies since the tax year start on line 060? . . . . **063** 1 Yes ☐ 2 No ☒
If **yes**, provide the date control was acquired **065**
YYYY MM DD

Is the date on line 061 a deemed tax year-end in according to subsection 249(3.1)? . . . . **066** 1 Yes ☐ 2 No ☒

Is the corporation a professional corporation that is a member of a partnership? . . . . **067** 1 Yes ☐ 2 No ☒

Is this the first year of filing after:
Incorporation? . . . . **070** 1 Yes ☐ 2 No ☒
Amalgamation? . . . . **071** 1 Yes ☐ 2 No ☒
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . **072** 1 Yes ☐ 2 No ☒
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . **076** 1 Yes ☐ 2 No ☒

Is this the final return up to dissolution? . . . . **078** 1 Yes ☐ 2 No ☒

If an election was made under section 261, state the functional currency used **079**

Is the corporation a resident of Canada?
080 1 Yes ☒ 2 No ☐ If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . **082** 1 Yes ☐ 2 No ☒
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
1 ☐ Exempt under paragraph 149(1)(e) or (l)
2 ☐ Exempt under paragraph 149(1)(j)
3 ☐ Exempt under paragraph 149(1)(t)
4 ☐ Exempt under other paragraphs of section 149

Do not use this area

095 **096**

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	☒	9
Is the corporation an associated CCPC?	160	☒	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161	☐	49
Does the corporation have any non-resident shareholders who own voting shares?	151	☐	19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162	☐	11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163	☐	44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164	☐	14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165	☐	15
Is the corporation claiming a loss or deduction from a tax shelter?	166	☐	T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	167	☐	T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168	☐	22
Did the corporation have any foreign affiliates during the year?	169	☐	25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170	☐	29
Has the corporation had any non-arm's length transactions with a non-resident?	171	☐	T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	☒	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172	☐	———
Does the corporation earn income from one or more Internet webpages or websites?	180	☐	88
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	☒	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202	☐	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	☐	3
Is the corporation claiming any type of losses?	204	☐	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	☒	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206	☐	6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	207	☐	7
Does the corporation have any property that is eligible for capital cost allowance?	208	☒	8
Does the corporation have any property that is eligible capital property?	210	☒	10
Does the corporation have any resource-related deductions?	212	☐	12
Is the corporation claiming deductible reserves (other than transitional reserves under section 34.2)?	213	☐	13
Is the corporation claiming a patronage dividend deduction?	216	☐	16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217	☐	17
Is the corporation an investment corporation or a mutual fund corporation?	218	☐	18
Is the corporation carrying on business in Canada as a non-resident corporation?	220	☐	20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221	☐	21
Does the corporation have any Canadian manufacturing and processing profits?	227	☐	27
Is the corporation claiming an investment tax credit?	231	☐	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232	☐	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	☒	———
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	☒	———
Is the corporation claiming a surtax credit?	237	☐	37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238	☐	38
Is the corporation claiming a Part I tax credit?	242	☐	42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243	☐	43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244	☐	45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249	☐	46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250	☐	39
Is the corporation claiming a Canadian film or video production tax credit refund?	253	☐	T1131
Is the corporation claiming a film or video production services tax credit refund?	254	☐	T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255	☐	92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	**256**	☐	T1134
Did the corporation have any controlled foreign affiliates?	**258**	☐	T1134
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	**259**	☐	T1135
Did the corporation transfer or loan property to a non-resident trust?	**260**	☐	T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	**261**	☐	T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	**262**	☐	T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	**263**	☐	T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	**264**	☐	T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	**265**	☐	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	**266**	☐	T2002
Has the corporation revoked any previous election made under subsection 89(11)?	**267**	☐	T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	**268**	☐	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	**269**	☐	54

Additional information

Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	**270**	1 Yes ☐	2 No ☒
Is the corporation inactive?	**280**	1 Yes ☐	2 No ☒

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electrical distributor	**285**	100.000 %
286		**287**	%
288		**289**	%

Did the corporation immigrate to Canada during the tax year?	**291**	1 Yes ☐	2 No ☒
Did the corporation emigrate from Canada during the tax year?	**292**	1 Yes ☐	2 No ☒
Do you want to be considered as a quarterly instalment remitter if you are eligible?	**293**	1 Yes ☐	2 No ☐
If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible	**294**	YYYY MM DD	
If the corporation's major business activity is construction, did you have any subcontractors during the tax year?	**295**	1 Yes ☐	2 No ☐

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.			**300**	272,580	A
Deduct: Charitable donations from Schedule 2	**311**				
Gifts to Canada, a province, or a territory from Schedule 2	**312**				
Cultural gifts from Schedule 2	**313**				
Ecological gifts from Schedule 2	**314**				
Gifts of medicine from Schedule 2	**315**				
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	**320**				
Part VI.1 tax deduction*	**325**				
Non-capital losses of previous tax years from Schedule 4	**331**				
Net capital losses of previous tax years from Schedule 4	**332**				
Restricted farm losses of previous tax years from Schedule 4	**333**				
Farm losses of previous tax years from Schedule 4	**334**				
Limited partnership losses of previous tax years from Schedule 4	**335**				
Taxable capital gains or taxable dividends allocated from a central credit union	**340**				
Prospector's and grubstaker's shares	**350**				
Subtotal			►		B
Subtotal (amount A **minus** amount B) (if negative, enter "0")				272,580	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions			**355**		D
Taxable income (amount C **plus** amount D)			**360**	272,580	
Income exempt under paragraph 149(1)(t)			**370**		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)				272,580	Z

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 8.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 . . . . **400** 272,580 A

Taxable income from line 360 on page 3, **minus** 100/28 3.57143 of the amount on line 632* on page 7, **minus** 1/(0.38 - X**) 4 times the amount on line 636*** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . . **405** 272,580 B

Business limit (see notes 1 and 2 below) . . . . **410** 360,000 C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.

2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 360,000 x **415** **** 111,537 D / 11,250 = ... 3,569,184 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . **425** F

Small business deduction

Amount A, B, C, or F, whichever is the least x 17 % = ... **430** G

Enter amount G on line 1 on page 7.

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

*** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

****** Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from page 3 (line 360 or amount Z, whichever applies)				272,580	A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27			B		
Amount QQ from Part 13 of Schedule 27			C		
Personal service business income	432		D		
Amount used to calculate the credit union deduction (amount F from Schedule 17)			E		
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least			F		
Aggregate investment income from line 440 on page 6*			G		
Total of amounts B to G			▶		H
Amount A **minus** amount H (if negative, enter "0")				272,580	I

Amount I	272,580	x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	/ 365	x	11.5 %	=	J
Amount I	272,580	x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	365 / 365	x	13 %	= 35,435	K

General tax reduction for Canadian-controlled private corporations – Amount J **plus** amount K	35,435	L

Enter amount L on line 638 on page 7.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)					M
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27			N		
Amount QQ from Part 13 of Schedule 27			O		
Personal service business income	434		P		
Amount used to calculate the credit union deduction (amount F from Schedule 17)			Q		
Total of amounts N to Q			▶		R
Amount M **minus** amount R (if negative, enter "0")					S

Amount S		x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	/ 365	x	11.5 %	=	T
Amount S		x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	365 / 365	x	13 %	=	U

General tax reduction – Amount T **plus** amount U		V

Enter amount V on line 639 on page 7.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 . . . . **440** ________ x 26 2 / 3 % = ... ________ A

Foreign non-business income tax credit from line 632 on page 7 . . . . ________ B

Deduct:

Foreign investment income from Schedule 7 . . . . **445** ________ x 9 1 / 3 % = ________ C

(if negative, enter "0") ________ ▶ ________ D

Amount A **minus** amount D (if negative, enter "0") . . . . ________ E

Taxable income from line 360 on page 3 . . . . ________ F

Deduct:

Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . ________ G

Foreign non-business income tax credit from line 632 on page 7 . . . ________ x 100 / 35 = ________ H

Foreign business income tax credit from line 636 on page 7 . . . . ________ x 1(0.38 – X*) / 4 = ________ I

Subtotal ________ ▶ ________ J

________ K

x 26 2 / 3 % = ________ L

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8) . . . . ________ M

Refundable portion of Part I tax – Amount E, L, or M, whichever is the least . . . . **450** ________ N

* General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year . . . . **460** ________

Deduct: Dividend refund for the previous tax year . . . . **465** ________

________ ▶ ________ O

Add the total of:

Refundable portion of Part I tax from line 450 above . . . . ________ P

Total Part IV tax payable from Schedule 3 . . . . ________ Q

Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation . . . . **480** ________

________ ▶ ________ R

Refundable dividend tax on hand at the end of the tax year – Amount O **plus** amount R . . . . **485** ________

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3 . . . . ________ x 1 / 3 = ________ S

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . ________ T

Dividend refund – Amount S or T, whichever is less (enter this amount on line 784 on page 8) . . . . ________

Part I tax

Base amount Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 %				550	103,580	A
Recapture of investment tax credit from Schedule 31				602		B

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6				i
Taxable income from line 360 on page 3				
Deduct:				
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least				
Net amount		▶		ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii	604		C
Subtotal (**add** amounts A to C)		103,580	D

Deduct:

Small business deduction from line 430 on page 4			1		
Federal tax abatement	608	27,258			
Manufacturing and processing profits deduction from Schedule 27	616				
Investment corporation deduction	620				
Taxed capital gains 624					
Additional deduction – credit unions from Schedule 17	628				
Federal foreign non-business income tax credit from Schedule 21	632				
Federal foreign business income tax credit from Schedule 21	636				
General tax reduction for CCPCs from amount L on page 5	638	35,435			
General tax reduction from amount V on page 5	639				
Federal logging tax credit from Schedule 21	640				
Federal qualifying environmental trust tax credit	648				
Investment tax credit from Schedule 31	652				
Subtotal		62,693	▶	62,693	E
Part I tax payable – Amount D **minus** amount E				40,887	F

Enter amount F on line 700 on page 8.

Summary of tax and credits

Federal tax

Part I tax payable from page 7	**700**		40,887
Part II surtax payable from Schedule 46	**708**		
Part III.1 tax payable from Schedule 55	**710**		
Part IV tax payable from Schedule 3	**712**		
Part IV.1 tax payable from Schedule 43	**716**		
Part VI tax payable from Schedule 38	**720**		
Part VI.1 tax payable from Schedule 43	**724**		
Part XIII.1 tax payable from Schedule 92	**727**		
Part XIV tax payable from Schedule 20	**728**		
Total federal tax			40,887

Add provincial or territorial tax:

Provincial or territorial jurisdiction . . . **750** ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	**760**	57,966	
Provincial tax on large corporations (Nova Scotia Schedule 342) (The Nova Scotia tax on large corporations is eliminated effective July 1, 2012.)	**765**		
Total provincial or territorial tax		57,966 ▶	57,966
Total tax payable	**770**		98,853 A

Deduct other credits:

Investment tax credit refund from Schedule 31	**780**		
Dividend refund from page 6	**784**		
Federal capital gains refund from Schedule 18	**788**		
Federal qualifying environmental trust tax credit refund	**792**		
Canadian film or video production tax credit refund (Form T1131)	**796**		
Film or video production services tax credit refund (Form T1177)	**797**		
Tax withheld at source	**800**		
Total payments on which tax has been withheld	**801**		
Provincial and territorial capital gains refund from Schedule 18	**808**		
Provincial and territorial refundable tax credits from Schedule 5	**812**		
Tax instalments paid	**840**	398,555	
Total credits	**890**	398,555 ▶	398,555 B

Refund code **894** 1 Overpayment 299,702 ◀

Balance (amount A **minus** amount B) -299,702

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid . . . .

Enclosed payment **898**

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information

910 Branch number

914 Institution number **918** Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? . . . **896** 1 Yes ☐ 2 No ☒

If this return was prepared by a tax preparer for a fee, provide their EFILE number . . . **920** D4481

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Certification

I, **950** Greco (Last name (print)) **951** Terry (First name (print)) **954** Vice-President (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2014-06-23 Date (yyyy/mm/dd)

Signature of the authorized signing officer of the corporation

956 (705) 759-6566 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . **957** 1 Yes ☒ 2 No ☐

958 Name (print)

959 Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français.

990 1

Privacy Act, personal information bank number CRA PPU 047

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2013-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	22,630,687	18,064,907
	Total tangible capital assets	2008	+	134,063,688	128,112,006
	Total accumulated amortization of tangible capital assets	2009	–	52,595,690	51,975,297
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	1,990,924	2,300,000
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	106,089,609	96,501,616
	Liabilities				
	Total current liabilities	3139	+	24,470,755	15,400,286
	Total long-term liabilities	3450	+	55,156,091	56,749,532
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	79,626,846	72,149,818
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	26,462,763	24,351,798
	Total liabilities and shareholder equity	3640	=	106,089,609	96,501,616
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	6,400,656	4,289,691

***** Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Canada Revenue Agency | Agence du revenu du Canada

SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2013-12-31

Income statement information

Description	GIFI	
Operating name	0001	
Description of the operation	0002	
Sequence number	0003	01

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+	85,504,200	78,026,469
	Cost of sales	8518	–	68,769,142	60,573,316
	Gross profit/loss	8519	=	16,735,058	17,453,153
	Cost of sales	8518	+	68,769,142	60,573,316
	Total operating expenses	9367	+	19,501,783	17,388,822
	Total expenses (mandatory field)	9368	=	88,270,925	77,962,138
	Total revenue (mandatory field)	8299	+	90,417,815	80,091,958
	Total expenses (mandatory field)	9368	–	88,270,925	77,962,138
	Net non-farming income	9369	=	2,146,890	2,129,820
	Farming income statement information				
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	2,146,890	2,129,820
	Total other comprehensive income	9998	=		
	Extraordinary items and income (linked to Schedule 140)				
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–	35,925	423,475
	Future (deferred) income tax provision	9995	–		
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	2,110,965	1,706,345

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Schedule 141

Notes checklist

Corporation's name	Business number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2013-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the **accountant**) who prepared or reported on the financial statements. If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and Guide T4012, *T2 Corporation – Income Tax Guide*.
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? . . . . **095** 1 Yes ☒ 2 No ☐

Is the accountant connected* with the corporation? . . . . **097** 1 Yes ☐ 2 No ☒

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note

If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you **do have** to complete Part 4, as applicable.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: **198**

Completed an auditor's report . . . . 1 ☒

Completed a review engagement report . . . . 2 ☐

Conducted a compilation engagement . . . . 3 ☐

Part 3 – Reservations

If you selected option **1** or **2** under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . . **099** 1 Yes ☐ 2 No ☒

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: **110**

Prepared the tax return (financial statements prepared by client) . . . . 1 ☐

Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . . 2 ☐

Were notes to the financial statements prepared? . . . . **101** 1 Yes ☒ 2 No ☐

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes? . . . . **104** 1 Yes ☐ 2 No ☒

Is re-evaluation of asset information mentioned in the notes? . . . . **105** 1 Yes ☐ 2 No ☒

Is contingent liability information mentioned in the notes? . . . . **106** 1 Yes ☒ 2 No ☐

Is information regarding commitments mentioned in the notes? . . . . **107** 1 Yes ☐ 2 No ☒

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . **108** 1 Yes ☐ 2 No ☒

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . **200** 1 Yes ☐ 2 No ☒

If **yes**, enter the amount recognized:

		In net income Increase (decrease)		**In OCI** Increase (decrease)
Property, plant, and equipment	**210**		**211**	
Intangible assets	**215**		**216**	
Investment property	**220**			
Biological assets	**225**			
Financial instruments	**230**		**231**	
Other	**235**		**236**	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? . . . . . **250** 1 Yes ☐ 2 No ☒

Did the corporation apply hedge accounting during the tax year? . . . . . **255** 1 Yes ☐ 2 No ☒

Did the corporation discontinue hedge accounting during the tax year? . . . . . **260** 1 Yes ☐ 2 No ☒

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . **265** 1 Yes ☐ 2 No ☒

If **yes**, you have to maintain a separate reconciliation.

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Net Income (Loss) for Income Tax Purposes

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2013-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125			2,110,965	A
Add:				
Provision for income taxes – current	101	35,925		
Amortization of tangible assets	104	3,538,651		
Loss on disposal of assets	111	110,632		
Non-deductible meals and entertainment expenses	121	1,595		
Subtotal of additions		3,686,803 ▶	3,686,803	
Other additions:				
Miscellaneous other additions:				
604				
Total	294			
Subtotal of other additions	199	0 ▶	0	
Total additions	500	3,686,803 ▶	3,686,803	B
Amount A **plus** amount B			5,797,768	
Deduct:				
Capital cost allowance from Schedule 8	403	5,290,947		
Cumulative eligible capital deduction from Schedule 10	405	234,241		
Subtotal of deductions		5,525,188 ▶	5,525,188	
Other deductions:				
Miscellaneous other deductions:				
704				
Total	394			
Subtotal of other deductions	499	0 ▶	0	
Total deductions	510	5,525,188 ▶	5,525,188	
Net income (loss) for income tax purposes – enter on line 300 of the T2 return			272,580	

T2 SCH 1 E (12)

Canada

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Schedule 5

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2013-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations.*
- For more information, see the *T2 Corporation – Income Tax Guide.*
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 ______ Enter the Regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2*** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes ☐	103		143		
Newfoundland and Labrador Offshore	004 1 Yes ☐	104		144		
Prince Edward Island	005 1 Yes ☐	105		145		
Nova Scotia	007 1 Yes ☐	107		147		
Nova Scotia Offshore	008 1 Yes ☐	108		148		
New Brunswick	009 1 Yes ☐	109		149		
Quebec	011 1 Yes ☐	111		151		
Ontario	013 1 Yes ☐	113		153		
Manitoba	015 1 Yes ☐	115		155		
Saskatchewan	017 1 Yes ☐	117		157		
Alberta	019 1 Yes ☐	119		159		
British Columbia	021 1 Yes ☐	121		161		
Yukon	023 1 Yes ☐	123		163		
Northwest Territories	025 1 Yes ☐	125		165		
Nunavut	026 1 Yes ☐	126		166		
Outside Canada	027 1 Yes ☐	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).

** If the corporation has income or loss from an international banking centre: the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act*. This does not apply to tax years starting after March 20, 2013.

*** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
272,580		272,580	12,266

Ontario basic income tax (from Schedule 500)	270	31,347			
Deduct: Ontario small business deduction (from Schedule 500)	402	19,081			
Subtotal		12,266	►	12,266	A6
Add:					
Ontario additional tax re Crown royalties (from Schedule 504)	274				
Ontario transitional tax debits (from Schedule 506)	276				
Recapture of Ontario research and development tax credit (from Schedule 508)	277				
Subtotal			►		B6
Subtotal (amount A6 **plus** amount B6)				12,266	C6
Deduct:					
Ontario resource tax credit (from Schedule 504)	404				
Ontario tax credit for manufacturing and processing (from Schedule 502)	406				
Ontario foreign tax credit (from Schedule 21)	408				
Ontario credit union tax reduction (from Schedule 500)	410				
Ontario transitional tax credits (from Schedule 506)	414				
Ontario political contributions tax credit (from Schedule 525)	415				
Other Ontario non-refundable credits					
Subtotal			►		D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")				12,266	E6
Deduct: Ontario research and development tax credit (from Schedule 508)				416	
Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0")				12,266	F6
Deduct: Ontario corporate minimum tax credit (from Schedule 510)				418	
Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0")				12,266	G6
Add:					
Ontario corporate minimum tax (from Schedule 510)	278	45,700			
Ontario special additional tax on life insurance corporations (from Schedule 512)	280				
Subtotal		45,700	►	45,700	H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)				57,966	I6
Deduct:					
Ontario qualifying environmental trust tax credit	450				
Ontario co-operative education tax credit (from Schedule 550)	452				
Ontario apprenticeship training tax credit (from Schedule 552)	454				
Ontario computer animation and special effects tax credit (from Schedule 554)	456				
Ontario film and television tax credit (from Schedule 556)	458				
Ontario production services tax credit (from Schedule 558)	460				
Ontario interactive digital media tax credit (from Schedule 560)	462				
Ontario sound recording tax credit (from Schedule 562)	464				
Ontario book publishing tax credit (from Schedule 564)	466				
Ontario innovation tax credit (from Schedule 566)	468				
Ontario business-research institute tax credit (from Schedule 568)	470				
Subtotal			►		J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255.			290	57,966	K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits	255	57,966

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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Schedule 8

Capital Cost Allowance (CCA)

Corporation's name	Business Number	Tax year end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2013-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes ☐ 2 No ☒

	1 Class number (See Note) 200	Description	2 Undepreciated capital cost at the beginning of the year (amount from column 12 of last year's schedule 8) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Adjustments and transfers** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % **** 212	9 Recapture of capital cost allowance***** (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ****** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
1.	1		27,197,496			0		27,197,496	4	0	0	1,087,900	26,109,596
2.	47		27,765,246	8,314,475		1,460,189	3,427,143	31,192,389	8	0	0	2,495,391	32,124,141
3.	8	Smart meters	3,738,115	244,768		0	122,384	3,860,499	20	0	0	772,100	3,210,783
4.	1	New Building	22,458,167	1,861,467		0	930,734	23,388,900	4	0	0	935,556	23,384,078
		Totals	81,159,024	10,420,710		1,460,189	4,480,261	85,639,284				5,290,947	84,828,598

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed.
Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Enter in column 4, "Adjustments and transfers", amounts that increase or reduce the undepreciated capital cost.
Items that **increase** the undepreciated capital cost:

- Amounts transferred under section 85, or transferred on amalgamation and winding-up of a subsidiary.
Items that **reduce** the undepreciated capital cost:
- Government assistance received or entitled to be received in the year, or a reduction of capital cost after the application of section 80.
See the *T2 Corporation Income Tax Guide* for other examples of adjustments and transfers to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments and transfers from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** Enter a rate only if you are using the declining balance method. For any other method (for example the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** For every entry in column 9, the "Recapture of capital cost allowance" there must be a corresponding entry in column 5, "Proceeds of dispositions during the year". The recapture and terminal loss rules do not apply to passenger vehicles in Class 10.1.

****** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2013-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	PUC Inc		89839 7518 RC0001	1					
2.	PUC Services Inc		87626 3526 RC0002	3					
3.	PUC TELECOM INC.		88614 1811 RC0001	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

T2 SCH 9 (11)

Canada

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2013-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0") . . . . **200** 3,346,306 A

Add: Cost of eligible capital property acquired during the taxation year **222**

Other adjustments **226**

Subtotal (line 222 plus line 226) x 3 / 4 = B

Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 . . . . **228** x 1 / 2 = C

amount B minus amount C (if negative, enter "0") ▶ D

Amount transferred on amalgamation or wind-up of subsidiary . . . . **224** E

Subtotal (add amounts A, D, and E) **230** 3,346,306 F

Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year . . . . **242** G

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) . . . . **244** H

Other adjustments . . . . **246** I

(add amounts G,H, and I) x 3 / 4 = **248** J

Cumulative eligible capital balance (amount F minus amount J) . . . . 3,346,306 K

(if amount K is negative, enter "0" at line M and proceed to Part 2)

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business **249**

amount K 3,346,306

less amount from line 249

Current year deduction . . . . 3,346,306 x 7.00 % = **250** 234,241 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 234,241 ▶ 234,241 L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") . . . . **300** 3,112,065 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)			N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988	400		1
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)	401		2
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402		3
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408		4
Line 3 minus line 4 (if negative, enter "0")		▶	5
Total of lines 1, 2 and 5			6
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400			7
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000			8
Subtotal (line 7 plus line 8)	409	▶	9
Line 6 minus line 9 (if negative, enter "0")		▶	O
Line N minus line O (if negative, enter "0")			P
Line 5		x 1 / 2 =	Q
Line P minus line Q (if negative, enter "0")			R
Amount R		x 2 / 3 =	S
Amount N or amount O, whichever is less			T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)	410		

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SCHEDULE 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)
2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 – Associated non-CCPC
5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2006	maximum $300,000
2007	$300,001 to $400,000

Calendar year	Acceptable range
2008	maximum $400,000
2009	$400,001 to $500,000

If the calendar year to which this agreement applies is after 2009, ensure that the total at line A does not exceed $500,000.

Allocating the business limit

Date filed (do not use this area) . . . . . **025** Year Month Day

Enter the calendar year to which the agreement applies . . . . . **050** Year 2013

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . **075** 1 Yes ☐ 2 No ☒

	1 Names of associated corporations **100**	2 Business Number of associated corporations **200**	3 Association code **300**	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % **350**	6 Business limit allocated* $ **400**
1	PUC Distribution Inc.	86709 6778 RC0001	1	500,000	72.0000	360,000
2	PUC Inc	89839 7518 RC0001	1	500,000	28.0000	140,000
3	PUC Services Inc	87626 3526 RC0002	1	500,000		
4	PUC TELECOM INC.	88614 1811 RC0001	1	500,000		
				Total	100.0000	500,000 **A**

Business limit reduction under subsection 125(5.1) of the ITA

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. If the tax year straddles January 1, 2009, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year, if $500,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2013-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

Provide only one number per shareholder

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) **100**	Business Number (If a corporation is not registered, enter "NR") **200**	Social insurance number **300**	Trust number **350**	Percentage common shares **400**	Percentage preferred shares **500**
1	PUC Inc	89839 7518 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Canada

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Schedule 500

Ontario Corporation Tax Calculation

Corporation's name	Business number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2013-12-31

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- All legislative references are to the federal *Income Tax Act* and *Income Tax Regulations*.
- This schedule is a worksheet only. You do not have to file it with your *T2 Corporation Income Tax Return*.

Part 1 – Calculation of Ontario basic rate of tax for the year

Number of days in the tax year before July 1, 2011		x	12.00 %	=	%	A1
Number of days in the tax year	365					
Number of days in the tax year after June 30, 2011	365	x	11.50 %	=	11.50000 %	A2
Number of days in the tax year	365					

Ontario basic rate of tax for the year (rate A1 **plus** A2) 11.50000 ▶ 11.50000 % A3

Part 2 – Calculation of Ontario basic income tax

Ontario taxable income *	272,580	B
Ontario basic income tax: amount B **multiplied** by Ontario basic rate of tax for the year (rate A3 from Part 1)	31,347	C

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit in addition to Ontario basic income tax, or has Ontario corporate minimum tax or Ontario special additional tax on life insurance corporations payable, enter amount C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Part 3 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

Income from active business carried on in Canada (amount from line 400 of the T2 return)	272,580	1
Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return)	272,580	2
Federal business limit before the application of subsection 125(5.1) (amount from line 410 of the T2 return)	360,000	3
Enter the least of amounts 1, 2, and 3	272,580	D

Ontario domestic factor: Ontario taxable income * / Taxable income earned in all provinces and territories ** = 272,580.00 / 272,580 = 1.00000 E

Amount D x factor E 272,580 a

Ontario taxable income (amount B from Part 2) 272,580 b

Ontario small business income (lesser of amount a and amount b) 272,580 F

Number of days in the tax year before July 1, 2011 / Number of days in the tax year = / 365 x 7.50 % = % G1

Number of days in the tax year after June 30, 2011 / Number of days in the tax year = 365 / 365 x 7.00 % = 7.00000 % G2

OSBD rate for the year (rate G1 **plus** G2) 7.00000 % G3

Ontario small business deduction: amount F **multiplied** by OSBD rate for the year (rate G3) 19,081 H

Enter amount H on line 402 of Schedule 5.

* Enter amount B from Part 2.

** Includes the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

Part 4 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Ontario adjusted small business income (lesser of amount D and amount b from Part 3) 272,580 I

Enter amount I on line K in Part 5 of this schedule or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Part 5 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

Amount D from Part 3 of Schedule 17			J
Deduct:			
Ontario adjusted small business income (amount I from Part 4)			K
Subtotal (amount J **minus** amount K) (if negative, enter "0")			L
OSBD rate for the year (rate G3 from Part 3)	7.00000 %		
Amount L **multiplied** by the OSBD rate for the year			M
Ontario domestic factor (factor E from Part 3)		1.00000	N
Ontario credit union tax reduction (amount M **multiplied** by factor N)			O

Enter amount O on line 410 of Schedule 5.

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Schedule 510

Ontario Corporate Minimum Tax

Corporation's name	Business number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2013-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	106,089,609
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	94,265,955
Total assets (total of lines 112 to 116)		200,355,564
Total revenue of the corporation for the tax year **	142	90,417,815
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	18,620,692
Total revenue (total of lines 142 to 146)		109,038,507

The corporation is subject to CMT if:

– for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.

– for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**

– Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.

– Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

– The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.

– A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**

– Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.

– If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.

– The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

– A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Adjusted net income/loss for CMT purposes

Net income/loss per financial statements *			**210**	2,110,965	
Add (to the extent reflected in income/loss):					
Provision for current income taxes/cost of current income taxes	**220**	35,925			
Provision for deferred income taxes (debits)/cost of future income taxes	**222**				
Equity losses from corporations	**224**				
Financial statement loss from partnerships and joint ventures	**226**				
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	**230**				
Other additions (see note below):					
Share of adjusted net income of partnerships and joint ventures **	**228**				
Total patronage dividends received, not already included in net income/loss	**232**				
281	**282**				
283	**284**				
Subtotal		35,925	▶	35,925	A
Deduct (to the extent reflected in income/loss):					
Provision for recovery of current income taxes/benefit of current income taxes	**320**				
Provision for deferred income taxes (credits)/benefit of future income taxes	**322**				
Equity income from corporations	**324**				
Financial statement income from partnerships and joint ventures	**326**				
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	**330**				
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	**332**				
Gain on donation of listed security or ecological gift	**340**				
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	**342**				
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	**344**				
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	**346**				
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	**348**				
Other deductions (see note below):					
Share of adjusted net loss of partnerships and joint ventures **	**328**				
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	**334**				
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	**336**				
Patronage dividends paid (from Schedule 16) not already included in net income/loss	**338**				
381	**382**				
383	**384**				
385	**386**				
387	**388**				
389	**390**				
Subtotal			▶		B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)			**490**	2,146,890	

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

– exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);

– include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

– Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive)			515	2,146,890		
Deduct:						
CMT loss available (amount R from Part 7)						
Minus: Adjustment for an acquisition of control *	518					
Adjusted CMT loss available		▶				C
Net income subject to CMT calculation (if negative, enter "0")			520	2,146,890		

Amount from line 520	2,146,890	x	Number of days in the tax year before July 1, 2010 / Number of days in the tax year	/ 365	x 4 % =		1
Amount from line 520	2,146,890	x	Number of days in the tax year after June 30, 2010 / Number of days in the tax year	365 / 365	x 2.7 % =	57,966	2
			Subtotal (amount 1 **plus** amount 2)			57,966	3

Gross CMT: amount on line 3 above x OAF **	540	57,966	
Deduct:			
Foreign tax credit for CMT purposes ***	550		
CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0")		57,966	D
Deduct:			
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		12,266	
Net CMT payable (if negative, enter "0")		45,700	E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income *****		=	

Ontario allocation factor	1.00000	F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

*****Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000".

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year *			G			
Deduct:						
CMT credit expired *	600					
CMT credit carryforward at the beginning of the current tax year * (see note below)			▶	620		
Add:						
CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below)				650		
CMT credit available for the tax year (amount on line 620 **plus** amount on line 650)						H
Deduct:						
CMT credit deducted in the current tax year (amount P from Part 5)						I
Subtotal (amount H **minus** amount I)						J
Add:						
Net CMT payable (amount E from Part 3)		45,700				
SAT payable (amount O from Part 6 of Schedule 512)						
Subtotal		45,700	▶		45,700	K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)				670	45,700	L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:

- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)						M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)			12,266	1		
For a corporation that is not a life insurance corporation:						
CMT after foreign tax credit deduction (amount D from Part 3)	57,966	2				
For a life insurance corporation:						
Gross CMT (line 540 from Part 3)		3				
Gross SAT (line 460 from Part 6 of Schedule 512)		4				
The **greater** of amounts 3 and 4		5				
Deduct: line 2 or line 5, whichever applies:			57,966	6		
Subtotal (if negative, enter "0")				▶		N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)			12,266			
Deduct:						
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5)						
Subtotal (if negative, enter "0")			12,266	▶	12,266	O
CMT credit deducted in the current tax year (least of amounts M, N, and O)						P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? **675** 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	CMT credit balance *
10th previous tax year	**680**
9th previous tax year	**681**
8th previous tax year	**682**
7th previous tax year	**683**
6th previous tax year	**684**
5th previous tax year	**685**
4th previous tax year	**686**
3rd previous tax year	**687**
2nd previous tax year	**688**
1st previous tax year	**689**
Total **	

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . ______ Q

Deduct:

CMT loss expired * . . . . **700** ______

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . ______ ► **720** ______

Add:

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) . . . . **750** ______

CMT loss available (line 720 **plus** line 750) . . . . ______ R

Deduct:

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . . ______

Subtotal (if negative, enter "0") ______ S

Add:

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) . . . . **760** ______

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . **770** ______ T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:

- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	**810**	**820**
9th previous tax year	**811**	**821**
8th previous tax year	**812**	**822**
7th previous tax year	**813**	**823**
6th previous tax year	**814**	**824**
5th previous tax year	**815**	**825**
4th previous tax year	**816**	**826**
3rd previous tax year	**817**	**827**
2nd previous tax year	**818**	**828**
1st previous tax year		**829**
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

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SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2013-12-31

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations **200**	Business number (Canadian corporation only) (see Note 1) **300**	Total assets* (see Note 2) **400**	Total revenue** (see Note 2) **500**
1	PUC Inc	89839 7518 RC0001	62,788,693	2,413,471
2	PUC Services Inc	87626 3526 RC0002	27,308,411	16,115,375
3	PUC TELECOM INC.	88614 1811 RC0001	4,168,851	91,846
		Total	**450** 94,265,955	**550** 18,620,692

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter ¨NR¨ if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

*** Rules for total assets**

- Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
- Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

**** Rules for total revenue**

- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
- Include the associated corporation's share of the total revenue of partnerships and joint ventures.
- If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

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SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2013-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
PUC Distribution Inc.

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	**110** Date of incorporation or amalgamation, whichever is the most recent	Year Month Day	**120** Ontario Corporation No.
Ontario		2000-02-18	1800173

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

200 Care of (if applicable)

210 Street number	**220** Street name/Rural route/Lot and Concession number	**230** Suite number
765	Queen Street	

240 Additional address information if applicable (line 220 must be completed first)

250 Municipality (e.g., city, town)	**260** Province/state	**270** Country	**280** Postal/zip code
Sault Ste Marie	ON	CA	P6A 6P2

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

300 1 If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 Greco — Last name

451 Terry — First name

454 ____________________, — Middle name(s)

460 2 Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 ☐ Please enter one of the following numbers in this box:

1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)

520 Street number

530 Street name/Rural route/Lot and Concession number

540 Suite number

550 Additional address information if applicable (line 530 must be completed first)

560 Municipality (e.g., city, town)

570 Province/state

580 Country

590 Postal/zip code

Part 6 – Language of preference

600 ☐ Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

Canada Revenue Agency / Agence du revenu du Canada

200

T2 Corporation Income Tax Return

055 **Do not use this area**

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act* and *Income Tax Regulations*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

Identification

Business number (BN) **001** 86709 6778 RC0001

Corporation's name

002 PUC Distribution Inc.

Address of head office

Has this address changed since the last time we were notified? . . . . **010** 1 Yes ☐ 2 No ☒

(If **yes**, complete lines 011 to 018.)

011 500 Second Line East

012

City **015** Sault Ste Marie

Province, territory, or state **016** ON

Country (other than Canada) **017**

Postal code/Zip code **018** P6B 4K1

Mailing address (if different from head office address)

Has this address changed since the last time we were notified? . . . . **020** 1 Yes ☐ 2 No ☒

(If **yes**, complete lines 021 to 028.)

021 c/o

022

023

City **025**

Province, territory, or state **026**

Country (other than Canada) **027**

Postal code/Zip code **028**

Location of books and records (if different from head office address)

Has the location of books and records changed since the last time we were notified? . . . . **030** 1 Yes ☐ 2 No ☒

(If **yes**, complete lines 031 to 038.)

031 500 Second Line East

032

City **035** Sault Ste Marie

Province,territory, or state **036** ON

Country (other than Canada) **037**

Postal code/Zip code **038** P6B 4K1

040 **Type of corporation at the end of the tax year**

1 ☐ Canadian-controlled private corporation (CCPC)

2 ☐ Other private corporation

3 ☐ Public corporation

4 ☐ Corporation controlled by a public corporation

5 ☒ Other corporation (specify, below)

Electrity Act

If the type of corporation changed during the tax year, provide the effective date of the change . . . . **043** YYYY MM DD

To which tax year does this return apply?

Tax year start **060** 2014-01-01 YYYY MM DD

Tax year-end **061** 2014-12-31 YYYY MM DD

Has there been an acquisition of control to which subsection 249(4) applies since the tax year start on line 060? . . . . **063** 1 Yes ☐ 2 No ☒

If **yes**, provide the date control was acquired . . . . **065** YYYY MM DD

Is the date on line 061 a deemed tax year-end according to subsection 249(3.1)? . . . . **066** 1 Yes ☐ 2 No ☒

Is the corporation a professional corporation that is a member of a partnership? . . . . **067** 1 Yes ☐ 2 No ☒

Is this the first year of filing after:

Incorporation? . . . . **070** 1 Yes ☐ 2 No ☒

Amalgamation? . . . . **071** 1 Yes ☐ 2 No ☒

If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . **072** 1 Yes ☐ 2 No ☒

If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . **076** 1 Yes ☐ 2 No ☒

Is this the final return up to dissolution? . . . . **078** 1 Yes ☐ 2 No ☒

If an election was made under section 261, state the functional currency used **079**

Is the corporation a resident of Canada?

080 1 Yes ☒ 2 No ☐ If **no**, give the country of residence on line 081 and complete and attach Schedule 97.

081

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . **082** 1 Yes ☐ 2 No ☒

If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

085

1 ☐ Exempt under paragraph 149(1)(e) or (l)

2 ☐ Exempt under paragraph 149(1)(j)

3 ☐ Exempt under paragraph 149(1)(t)

4 ☐ Exempt under other paragraphs of section 149

Do not use this area

095 **096** **898**

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	☒	9
Is the corporation an associated CCPC?	160	☒	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161	☐	49
Does the corporation have any non-resident shareholders who own voting shares?	151	☐	19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162	☐	11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163	☐	44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164	☐	14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165	☐	15
Is the corporation claiming a loss or deduction from a tax shelter?	166	☐	T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	167	☐	T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168	☐	22
Did the corporation own any shares in one or more foreign affiliates in the tax year?	169	☐	25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170	☐	29
Did the corporation have a total amount over $1 million of reportable transactions with non-arm's length non-residents?	171	☐	T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	☒	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172	☐	———
Does the corporation earn income from one or more Internet webpages or websites?	180	☐	88
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	☒	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202	☐	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	☐	3
Is the corporation claiming any type of losses?	204	☒	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	☒	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206	☐	6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	207	☐	7
Does the corporation have any property that is eligible for capital cost allowance?	208	☒	8
Does the corporation have any property that is eligible capital property?	210	☒	10
Does the corporation have any resource-related deductions?	212	☐	12
Is the corporation claiming deductible reserves (other than transitional reserves under section 34.2)?	213	☐	13
Is the corporation claiming a patronage dividend deduction?	216	☐	16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217	☐	17
Is the corporation an investment corporation or a mutual fund corporation?	218	☐	18
Is the corporation carrying on business in Canada as a non-resident corporation?	220	☐	20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221	☐	21
Does the corporation have any Canadian manufacturing and processing profits?	227	☐	27
Is the corporation claiming an investment tax credit?	231	☐	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232	☐	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	☒	33/34/35
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	☒	———
Is the corporation claiming a surtax credit?	237	☐	37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238	☐	38
Is the corporation claiming a Part I tax credit?	242	☐	42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243	☐	43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244	☐	45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249	☐	46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250	☐	39
Is the corporation claiming a Canadian film or video production tax credit refund?	253	☐	T1131
Is the corporation claiming a film or video production services tax credit refund?	254	☐	T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255	☐	92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates in the tax year?	**271**	☐	T1134
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	**259**	☐	T1135
Did the corporation transfer or loan property to a non-resident trust?	**260**	☐	T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	**261**	☐	T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	**262**	☐	T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	**263**	☐	T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	**264**	☐	T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	**265**	☐	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	**266**	☐	T2002
Has the corporation revoked any previous election made under subsection 89(11)?	**267**	☐	T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	**268**	☐	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	**269**	☐	54

Additional information

Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	**270**	1 Yes ☐	2 No ☒
Is the corporation inactive?	**280**	1 Yes ☐	2 No ☒

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electrical power distribution	**285**	100.000 %
286		**287**	%
288		**289**	%

Did the corporation immigrate to Canada during the tax year?	**291**	1 Yes ☐	2 No ☒
Did the corporation emigrate from Canada during the tax year?	**292**	1 Yes ☐	2 No ☒
Do you want to be considered as a quarterly instalment remitter if you are eligible?	**293**	1 Yes ☐	2 No ☐
If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible	**294**	YYYY MM DD	
If the corporation's major business activity is construction, did you have any subcontractors during the tax year?	**295**	1 Yes ☐	2 No ☐

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.			**300**	-1,149,357	A
Deduct: Charitable donations from Schedule 2	**311**				
Gifts to Canada, a province, or a territory from Schedule 2	**312**				
Cultural gifts from Schedule 2	**313**				
Ecological gifts from Schedule 2	**314**				
Gifts of medicine from Schedule 2	**315**				
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	**320**				
Part VI.1 tax deduction*	**325**				
Non-capital losses of previous tax years from Schedule 4	**331**				
Net capital losses of previous tax years from Schedule 4	**332**				
Restricted farm losses of previous tax years from Schedule 4	**333**				
Farm losses of previous tax years from Schedule 4	**334**				
Limited partnership losses of previous tax years from Schedule 4	**335**				
Taxable capital gains or taxable dividends allocated from a central credit union	**340**				
Prospector's and grubstaker's shares	**350**				
Subtotal			►		B
Subtotal (amount A **minus** amount B) (if negative, enter "0")					C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions			**355**		D
Taxable income (amount C **plus** amount D)			**360**		
Income exempt under paragraph 149(1)(t)			**370**		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)					Z

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 8.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 . . . . **400** ________ A

Taxable income from line 360 on page 3, **minus** 100/28 3.57143 of the amount on line 632* on page 7, **minus** 4 times the amount on line 636** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . . **405** ________ B

Business limit (see notes 1 and 2 below) . . . . **410** ________ C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.

2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C ________ x $\frac{\textbf{415}\ ^{***}\ 206{,}748\ \text{D}}{11{,}250}$ = ... ________ E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . **425** ________ F

Small business deduction

Amount A, B, C, or F, whichever is the least ________ x 17 % = ... **430** ________ G

Enter amount G on line I on page 7.

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

*** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from page 3 (line 360 or amount Z, whichever applies)					A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27			B		
Amount QQ from Part 13 of Schedule 27			C		
Personal service business income	**432**		D		
Amount used to calculate the credit union deduction (amount F from Schedule 17)			E		
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least			F		
Aggregate investment income from line 440 on page 6*			G		
Subtotal (**add** amounts B to G)			▶		H
Amount A **minus** amount H (if negative, enter "0")					I
General tax reduction for Canadian-controlled private corporations – Amount I **multiplied** by 13 %					J

Enter amount J on line 638 on page 7.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)					K
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27			L		
Amount QQ from Part 13 of Schedule 27			M		
Personal service business income	**434**		N		
Amount used to calculate the credit union deduction (amount F from Schedule 17)			O		
Subtotal (**add** amounts L to O)			▶		P
Amount K **minus** amount P (if negative, enter "0")					Q
General tax reduction – Amount Q **multiplied** by 13 %					R

Enter amount R on line 639 on page 7.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 . . . . **440** ________ x 26 2 / 3 % = ... ________ A

Foreign non-business income tax credit from line 632 on page 7 . . . . ________ B

Deduct:

Foreign investment income from Schedule 7 . . . . **445** ________ x 9 1 / 3 % = ________ C

(if negative, enter "0") ________ ▶ ________ D

Amount A **minus** amount D (if negative, enter "0") . . . . ________ E

Taxable income from line 360 on page 3 . . . . ________ F

Deduct:

Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . ________ G

Foreign non-business income tax credit from line 632 on page 7 . . . ________ x 100 / 35 = ________ H

Foreign business income tax credit from line 636 on page 7 . . . . ________ x 4 = ________ I

Subtotal ________ ▶ ________ J

________ K

x 26 2 / 3 % = ________ L

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8) . . . . ________ M

Refundable portion of Part I tax – Amount E, L, or M, whichever is the least . . . . **450** ________ N

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year . . . . **460** ________

Deduct: Dividend refund for the previous tax year . . . . **465** ________

________ ▶ ________ O

Add the total of:

Refundable portion of Part I tax from line 450 above . . . . ________ P

Total Part IV tax payable from Schedule 3 . . . . ________ Q

Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation . . . . **480** ________

________ ▶ ________ R

Refundable dividend tax on hand at the end of the tax year – Amount O **plus** amount R . . . . **485** ________

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3 . . . . ________ x 1 / 3 = ________ S

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . ________ T

Dividend refund – Amount S or T, whichever is less . . . . ________ U

Enter amount U on line 784 on page 8.

Part I tax

Base amount Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 %	550		A
Recapture of investment tax credit from Schedule 31	602		B

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6			C
Taxable income from line 360 on page 3			D
Deduct: Amount from line 400, 405, 410, or 425 on page 4, whichever is the least			E
Net amount (amount D **minus** amount E) ▶			F

Refundable tax on CCPC's investment income – 6 2/3 % of whichever is less: amount C or amount F	604		G
Subtotal (**add** amounts A, B, and G)			H

Deduct:

Small business deduction from line 430 on page 4			I
Federal tax abatement	608		
Manufacturing and processing profits deduction from Schedule 27	616		
Investment corporation deduction	620		
Taxed capital gains	624		
Additional deduction – credit unions from Schedule 17	628		
Federal foreign non-business income tax credit from Schedule 21	632		
Federal foreign business income tax credit from Schedule 21	636		
General tax reduction for CCPCs from amount J on page 5	638		
General tax reduction from amount R on page 5	639		
Federal logging tax credit from Schedule 21	640		
Eligible Canadian bank deduction under section 125.21	641		
Federal qualifying environmental trust tax credit	648		
Investment tax credit from Schedule 31	652		
Subtotal ▶			J

Part I tax payable – Amount H **minus** amount J			K

Enter amount K on line 700 on page 8.

Summary of tax and credits

Federal tax

Part I tax payable from amount K on page 7	**700**	
Part II surtax payable from Schedule 46	**708**	
Part III.1 tax payable from Schedule 55	**710**	
Part IV tax payable from Schedule 3	**712**	
Part IV.1 tax payable from Schedule 43	**716**	
Part VI tax payable from Schedule 38	**720**	
Part VI.1 tax payable from Schedule 43	**724**	
Part XIII.1 tax payable from Schedule 92	**727**	
Part XIV tax payable from Schedule 20	**728**	
Total federal tax		

Add provincial or territorial tax:

Provincial or territorial jurisdiction **750** ON

(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	**760**	23,460	
Total tax payable	**770**	23,460	A

Deduct other credits:

Investment tax credit refund from Schedule 31	**780**			
Dividend refund from amount U on page 6	**784**			
Federal capital gains refund from Schedule 18	**788**			
Federal qualifying environmental trust tax credit refund	**792**			
Canadian film or video production tax credit refund (Form T1131)	**796**			
Film or video production services tax credit refund (Form T1177)	**797**			
Tax withheld at source	**800**			
Total payments on which tax has been withheld **801**				
Provincial and territorial capital gains refund from Schedule 18	**808**			
Provincial and territorial refundable tax credits from Schedule 5	**812**			
Tax instalments paid	**840**	199,278		
Total credits	**890**	199,278	199,278	B

Refund code **894** 1 Overpayment 175,818

Balance (amount A **minus** amount B) -175,818

If the result is positive, you have a **balance unpaid**.
If the result is negative, you have an **overpayment**.
Enter the amount on whichever line applies.
Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid

For information on how to make your payment, go to **www.cra-arc.gc.ca/payments**.

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information

910 Branch number

914 Institution number

918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? **896** 1 Yes ☐ 2 No ☒

If this return was prepared by a tax preparer for a fee, provide their EFILE number **920** D4481

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Certification

I, **950** Greco (Last name (print)) **951** Terry (First name (print)) **954** Vice-President (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2015-06-19 Date (yyyy/mm/dd)

Signature of the authorized signing officer of the corporation

956 (705) 759-6566 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below **957** 1 Yes ☒ 2 No ☐

958 Name (print)

959 Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. **990** 1

Privacy Act, personal information bank number CRA PPU 047

Canada Revenue Agency   Agence du revenu du Canada

Schedule 141

Notes Checklist

Corporation's name	Business number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2014-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the **accountant**) who prepared or reported on the financial statements. If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and T4012, *T2 Corporation – Income Tax Guide.*
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? . . . . . **095** 1 Yes ☒ 2 No ☐

Is the accountant connected* with the corporation? . . . . . **097** 1 Yes ☐ 2 No ☒

Note

If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you **do have** to complete Part 4, as applicable.

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: **198**

Completed an auditor's report . . . . . 1 ☒

Completed a review engagement report . . . . . 2 ☐

Conducted a compilation engagement . . . . . 3 ☐

Part 3 – Reservations

If you selected option 1 or 2 under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . . . **099** 1 Yes ☐ 2 No ☒

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: **110**

Prepared the tax return (financial statements prepared by client) . . . . . 1 ☐

Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . . . 2 ☐

Were notes to the financial statements prepared? . . . . . **101** 1 Yes ☒ 2 No ☐

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes? . . . . . **104** 1 Yes ☐ 2 No ☒

Is re-evaluation of asset information mentioned in the notes? . . . . . **105** 1 Yes ☐ 2 No ☒

Is contingent liability information mentioned in the notes? . . . . . **106** 1 Yes ☒ 2 No ☐

Is information regarding commitments mentioned in the notes? . . . . . **107** 1 Yes ☐ 2 No ☒

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . **108** 1 Yes ☐ 2 No ☒

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . **200** 1 Yes ☐ 2 No ☒

If **yes**, enter the amount recognized:		**In net income** Increase (decrease)		**In OCI** Increase (decrease)
Property, plant, and equipment	**210**		**211**	
Intangible assets	**215**		**216**	
Investment property	**220**			
Biological assets	**225**			
Financial instruments	**230**		**231**	
Other	**235**		**236**	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? . . . . . **250** 1 Yes ☐ 2 No ☒

Did the corporation apply hedge accounting during the tax year? . . . . . **255** 1 Yes ☐ 2 No ☒

Did the corporation discontinue hedge accounting during the tax year? . . . . . **260** 1 Yes ☐ 2 No ☒

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . **265** 1 Yes ☐ 2 No ☒

If **yes**, you have to maintain a separate reconciliation.

SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2014-12-31

Assets – lines 1000 to 2599

1000	4,118,664	**1060**	7,544,347	**1062**	10,004,921
1120	1,614,472	**1480**	28,521	**1483**	497,819
1484	62,200	**1599**	23,870,944	**1600**	852,393
1680	26,327,087	**1681**	-1,731,553	**1740**	29,570,082
1741	-14,092,945	**1785**	83,906,624	**1786**	-40,267,974
2008	140,656,186	**2009**	-56,092,472	**2420**	1,482,115
2421	1,403,460	**2589**	2,885,575	**2599**	111,320,233

Liabilities – lines 2600 to 3499

2620	10,791,840	**2770**	563,782	**2860**	1,945,721
2920	16,905,879	**2961**	854,761	**3139**	31,061,983
3145	24,631,520	**3260**	26,534,040	**3320**	1,482,458
3450	52,648,018	**3499**	83,710,001		

Shareholder equity – lines 3500 to 3640

3500	20,062,107	**3600**	7,548,125	**3620**	27,610,232
3640	111,320,233				

Retained earnings – lines 3660 to 3849

3660	6,400,656	**3680**	1,147,469	**3849**	7,548,125

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2014-12-31

Description

Sequence number **0003** 01

Revenue – lines 8000 to 8299

8000	86,859,902	**8089**	86,859,902	**8090**	7,555
8230	4,143,950	**8299**	91,011,407		

Cost of sales – lines 8300 to 8519

8320	70,473,134	**8518**	70,473,134	**8519**	16,386,768

Operating expenses – lines 8520 to 9369

8523	4,070	**8670**	3,657,061	**8710**	259,935
8714	2,756,657	**8717**	1,373,301	**9270**	2,516,075
9273	5,773,407	**9284**	3,328,861	**9367**	19,669,367
9368	90,142,501	**9369**	868,906		

Extraordinary items and taxes – lines 9970 to 9999

9970	868,906	**9990**	-278,563	**9999**	1,147,469

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Canada Revenue Agency / Agence du revenu du Canada

Net Income (Loss) for Income Tax Purposes

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2014-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125				1,147,469	A
Add:					
Provision for income taxes – current		101	-278,563		
Amortization of tangible assets		104	3,657,061		
Non-deductible meals and entertainment expenses		121	2,035		
Subtotal of additions			3,380,533 ▶	3,380,533	
Other additions:					
Miscellaneous other additions:					
604					
Total		294			
Subtotal of other additions		199	0 ▶	0	
Total additions		500	3,380,533 ▶	3,380,533	B
Amount A **plus** amount B				4,528,002	
Deduct:					
Capital cost allowance from Schedule 8		403	5,459,514		
Cumulative eligible capital deduction from Schedule 10		405	217,845		
Subtotal of deductions			5,677,359 ▶	5,677,359	
Other deductions:					
Miscellaneous other deductions:					
704					
Total		394			
Subtotal of other deductions		499	0 ▶	0	
Total deductions		510	5,677,359 ▶	5,677,359	
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				-1,149,357	

T2 SCH 1 E (12)

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Schedule 4

Corporation Loss Continuity and Application

Corporation's name	Business number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2014-12-31

- Use this form to determine the continuity and use of available losses; to determine a current-year non-capital loss, farm loss, restricted farm loss, or limited partnership loss; to determine the amount of restricted farm loss and limited partnership loss that can be applied in a year; and to ask for a loss carryback to previous years.
- A corporation can choose whether or not to deduct an available loss from income in a tax year. The corporation can deduct losses in any order. However, for each type of loss, deduct the oldest loss first.
- According to subsection 111(4) of the *Income Tax Act*, when control has been acquired, no amount of capital loss incurred for a tax year ending before that time is deductible in computing taxable income in a tax year ending after that time. Also, no amount of capital loss incurred in a tax year ending after that time is deductible in computing taxable income of a tax year ending before that time.
- When control has been acquired, subsection 111(5) provides for similar treatment of non-capital and farm losses, except as listed in paragraphs 111(5)(a) and (b).
- For information on these losses, see the *T2 Corporation – Income Tax Guide*.
- File one completed copy of this schedule with the T2 return, or send the schedule by itself to the tax centre where the return is filed.
- All legislative references are to the *Income Tax Act*.

Part 1 – Non-capital losses

Determination of current-year non-capital loss

Net income (loss) for income tax purposes				-1,149,357	A
Deduct: (increase a loss)					
Net capital losses deducted in the year (enter as a positive amount)			a		
Taxable dividends deductible under section 112 or subsections 113(1) or 138(6)			b		
Amount of Part VI.1 tax deductible			c		
Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2)			d		
Subtotal (total of amounts a to d)			▶		B
Subtotal (amount A **minus** amount B; if positive, enter "0")				-1,149,357	C
Deduct: (increase a loss)					
Section 110.5 or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions					D
Subtotal (amount C **minus** amount D)				-1,149,357	E
Add: (decrease a loss)					
Current-year farm loss (whichever is less: the net loss from farming or fishing included in the income, or the non-capital loss before deducting the farm loss)					F
Current-year non-capital loss (amount E **plus** amount F; if positive, enter "0")				-1,149,357	G

If amount G is negative, enter it on line 110 as a positive.

Continuity of non-capital losses and request for a carryback

Non-capital loss at the end of the previous tax year			e		
Deduct: Non-capital loss expired*	100		f		
Non-capital losses at the beginning of the tax year (amount e **minus** amount f)	102		▶		H
Add:					
Non-capital losses transferred on an amalgamation or the wind-up of a subsidiary corporation	105		g		
Current-year non-capital loss (from amount G)	110	1,149,357	h		
Subtotal (amount g **plus** amount h)		1,149,357	▶	1,149,357	I
Subtotal (amount H **plus** amount I)				1,149,357	J

* A non-capital loss expires as follows:
- after **10** tax years if it arose in a tax year ending after March 22, 2004, and before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

An allowable business investment loss becomes a net capital loss after **10** tax years if it arose in a tax year ending after March 22, 2004.

Part 1 – Non-capital losses (continued)

Deduct:

Other adjustments (includes adjustments for an acquisition of control)	150		i		
Section 80 – Adjustments for forgiven amounts	140		j		
Subsection 111(10) – Adjustments for fuel tax rebate			j.1		
Non-capital losses of previous tax years applied in the current tax year Enter amount k on line 331 of the T2 Return.	130		k		
Current and previous year non-capital losses applied against current-year taxable dividends subject to Part IV tax**	135		l		
Subtotal (total of amounts i to l)			▶		K
Non-capital losses before any request for a carryback (amount J **minus** amount K)				1,149,357	L

Deduct – **Request to carry back non-capital loss to:**

First previous tax year to reduce taxable income	901		m		
Second previous tax year to reduce taxable income	902		n		
Third previous tax year to reduce taxable income	903	1,149,357	o		
First previous tax year to reduce taxable dividends subject to Part IV tax	911		p		
Second previous tax year to reduce taxable dividends subject to Part IV tax	912		q		
Third previous tax year to reduce taxable dividends subject to Part IV tax	913		r		
Total of requests to carry back non-capital losses to previous tax years (total of amounts m to r)		1,149,357	▶	1,149,357	M
Closing balance of non-capital losses to be carried forward to future tax years (amount L **minus** amount M)	180				N

** Amount l is the total of lines 330 and 335 from Schedule 3, *Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation*.

Part 2 – Capital losses

Continuity of capital losses and request for a carryback

Capital losses at the end of the previous tax year	200		a		
Capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation	205		b		
Subtotal (amount a **plus** amount b)			▶		A

Deduct:

Other adjustments (includes adjustments for an acquisition of control)	250		c		
Section 80 – Adjustments for forgiven amounts	240		d		
Subtotal (amount c **plus** amount d)			▶		B
Subtotal (amount A **minus** amount B)					C
Add: Current-year capital loss (from the calculation on Schedule 6, *Summary of Dispositions of Capital Property*)	210				D
Unused non-capital losses that expired in the tax year*			e		
Allowable business investment losses (ABIL) that expired as non-capital losses in the tax year**			f		
Enter amount e or f, whichever is less	215		g		
ABILs expired as non-capital loss: line 215 **divided** by 0.500000	220				E
Subtotal (total of amounts C to E)					F

Note
If there has been an amalgamation or a windup of a subsidiary, do a separate calculation of the ABIL expired as non-capital loss for each predecessor or subsidiary. Add all these amounts and enter the total on line 220 above.

* If the losses were incurred in a tax year ending after March 22, 2004, and before 2006, enter the losses from the 11th previous tax year. Enter the losses from the 21st previous tax year if the losses were incurred in a tax year ending after 2005. Enter the part that was not used in previous years and the current year on line e.

** If the losses were incurred in a tax year ending after March 22, 2004, enter the losses from the 11th previous tax year. Enter the full amount on line f.

Part 2 – Capital losses (continued)

Deduct: Capital losses from previous tax years applied against the current-year net capital gain***	225		G
Capital losses before any request for a carryback (amount F **minus** amount G)			H

Deduct – **Request to carry back capital loss to******:

	Capital gain (100%)		Amount carried back (100%)			
First previous tax year		951		h		
Second previous tax year	37,523	952		i		
Third previous tax year	62,000	953		j		
Subtotal (total of amounts h to j)				▶		I
Closing balance of capital losses to be carried forward to future tax years (amount H **minus** amount I)				280		J

*** To get the net capital losses required to reduce the taxable capital gain included in the net income (loss) for the purpose of current-year tax, enter the amount from line 225 **multiplied** by 50% on line 332 of the T2 return.

**** On line 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, **multiply** this amount by the 50% inclusion rate.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

Farm losses at the end of the previous tax year			a		
Deduct: Farm loss expired*	300		b		
Farm losses at the beginning of the tax year (amount a **minus** amount b)	302		▶		A
Add:					
Farm losses transferred on the amalgamation or the windup of a subsidiary corporation	305		c		
Current-year farm loss (amount F in Part 1)	310		d		
Subtotal (amount c **plus** amount d)			▶		B
Subtotal (amount A **plus** amount B)					C
Deduct:					
Other adjustments (includes adjustments for an acquisition of control)	350		e		
Section 80 – Adjustments for forgiven amounts	340		f		
Farm losses of previous tax years applied in the current tax year Enter amount g on line 334 of the T2 Return.	330		g		
Current and previous year farm losses applied against current-year taxable dividends subject to Part IV tax**	335		h		
Subtotal (total of amounts e to h)			▶		D
Farm losses before any request for a carryback (amount C **minus** amount D)					E

Deduct – **Request to carry back farm loss to:**

First previous tax year to reduce taxable income	921		i		
Second previous tax year to reduce taxable income	922		j		
Third previous tax year to reduce taxable income	923		k		
First previous tax year to reduce taxable dividends subject to Part IV tax	931		l		
Second previous tax year to reduce taxable dividends subject to Part IV tax	932		m		
Third previous tax year to reduce taxable dividends subject to Part IV tax	933		n		
Subtotal (total of amounts i to n)			▶		F
Closing balance of farm losses to be carried forward to future tax years (amount E **minus** amount F)			380		G

* A farm loss expires as follows:
- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

** Amount h is the total of lines 340 and 345 from Schedule 3.

Part 4 – Restricted farm losses

Current-year restricted farm loss

Total losses for the year from farming business			**485**		A
Minus the deductible farm loss:					
(amount A above ______ – $2,500) **divided** by 2 =		a			
Amount a or $ 15,000 *, whichever is less		b			
	2,500	c			
Subtotal (amount b **plus** amount c)	2,500	▶		2,500	B
Current-year restricted farm loss (amount A **minus** amount B)					C

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year			d		
Deduct: Restricted farm loss expired**	**400**		e		
Restricted farm losses at the beginning of the tax year (amount d **minus** amount e)	**402**		▶		D
Add:					
Restricted farm losses transferred on the amalgamation or the wind-up of a subsidiary corporation	**405**		f		
Current-year restricted farm loss (from amount C) Enter amount g on line 233 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*.	**410**		g		
Subtotal (amount f **plus** amount g)			▶		E
Subtotal (amount D **plus** amount E)					F
Deduct:					
Restricted farm losses from previous tax years applied against current farming income Enter amount h on line 333 of the T2 return.	**430**		h		
Section 80 – Adjustments for forgiven amounts	**440**		i		
Other adjustments	**450**		j		
Subtotal (total of amounts h to j)			▶		G
Restricted farm losses before any request for a carryback (amount F **minus** amount G)					H

Deduct – **Request to carry back restricted farm loss to:**

First previous tax year to reduce farming income	**941**		k		
Second previous tax year to reduce farming income	**942**		l		
Third previous tax year to reduce farming income	**943**		m		
Subtotal (total of amounts k to m)			▶		I
Closing balance of restricted farm losses to be carried forward to future tax years (amount H **minus** amount I)			**480**		J

Note

The total losses for the year from all farming businesses are calculated without including scientific research expenses.

* For tax years that end before March 21, 2013, use $6,250 instead of $15,000.

** A restricted farm loss expires as follows:

- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

Part 5 – Listed personal property losses

Continuity of listed personal property loss and request for a carryback

Listed personal property losses at the end of the previous tax year a

Deduct: Listed personal property loss expired after seven tax years **500** b

Listed personal property losses at the beginning of the tax year (amount a **minus** amount b) **502** ▶ A

Add: Current-year listed personal property loss (from Schedule 6) **510** B

Subtotal (amount A **plus** amount B) C

Deduct:

Previous year personal property losses applied in the current tax year against listed personal property gains **530** c

Enter amount c on line 655 of Schedule 6.

Other adjustments **550** d

Subtotal (amount c **plus** amount d) ▶ D

Listed personal property losses remaining before any request for a carryback (amount C **minus** amount D) E

Deduct – **Request to carry back listed personal property loss to:**

First previous tax year to reduce listed personal property gains **961** e

Second previous tax year to reduce listed personal property gains **962** f

Third previous tax year to reduce listed personal property gains **963** g

Subtotal (total of amounts e to g) ▶ F

Closing balance of listed personal property losses to be carried forward to future tax years (amount E **minus** amount F) **580** G

Part 7 – Limited partnership losses

Current-year limited partnership losses

1	2	3	4	5	6	7
Partnership identifier **600**	Tax year ending YYYY/MM/DD **602**	Corporation's share of limited partnership loss **604**	Corporation's at-risk amount **606**	Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses **608**	Column 4 **minus** column 5 (if negative, enter "0")	Current-year limited partnership losses (column 3 **minus** 6) **620**

Total (enter this amount on line 222 of Schedule 1)

Limited partnership losses from previous tax years that may be applied in the current year

1	2	3	4	5	6	7
Partnership identifier **630**	Tax year ending YYYY/MM/DD **632**	Limited partnership losses at the end of the previous tax year **634**	Corporation's at-risk amount **636**	Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses **638**	Column 4 **minus** column 5 (if negative, enter "0")	Limited partnership losses that may be applied in the year (the lesser of columns 3 and 6) **650**

Continuity of limited partnership losses that can be carried forward to future tax years

1	2	3	4	5	6
Partnership identifier **660**	Limited partnership losses at the end of the previous tax year **662**	Limited partnership losses transferred on an amalgamation or the windup of a subsidiary **664**	Current-year limited partnership losses (from line 620) **670**	Limited partnership losses applied in the current year (cannot be more than line 650) **675**	Current year limited partnership losses closing balance to be carried forward to future years (column 2 **plus** column 3 **plus** column 4 **minus** column 5) **680**

Total (enter this amount on line 335 of the T2 return)

Note

If you have any current–or previous–year losses, enter your partnership identifier on line 600, 630, or 660.

Part 8 – Election under paragraph 88(1.1)(f)

If you are making an election under paragraph 88(1.1)(f), check the box . . . . **190** Yes ☐

Further to a winding-up of a subsidiary, the portion of a non-capital loss, restricted farm loss, farm loss, or limited partnership loss from a wholly-owned subsidiary is deemed to be the loss of a parent from its tax year starting after the commencement of the winding-up.

Note

This election is only applicable for wind-ups under subsection 88(1) that are reported on Schedule 24, *First-Time Filer after Incorporation, Amalgamation, or Winding-up of a Subsidiary into a Parent*, and the deemed provision is only for the tax years that start after the commencement of the wind-up.

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Schedule 5

Tax Calculation Supplementary – Corporations

Corporation's name	Business Number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2014-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations.*
- For more information, see the *T2 Corporation – Income Tax Guide.*
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 ____________________ Enter the Regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2*** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	**003** 1 Yes ☐	**103**		**143**		
Newfoundland and Labrador Offshore	**004** 1 Yes ☐	**104**		**144**		
Prince Edward Island	**005** 1 Yes ☐	**105**		**145**		
Nova Scotia	**007** 1 Yes ☐	**107**		**147**		
Nova Scotia Offshore	**008** 1 Yes ☐	**108**		**148**		
New Brunswick	**009** 1 Yes ☐	**109**		**149**		
Quebec	**011** 1 Yes ☐	**111**		**151**		
Ontario	**013** 1 Yes ☐	**113**		**153**		
Manitoba	**015** 1 Yes ☐	**115**		**155**		
Saskatchewan	**017** 1 Yes ☐	**117**		**157**		
Alberta	**019** 1 Yes ☐	**119**		**159**		
British Columbia	**021** 1 Yes ☐	**121**		**161**		
Yukon	**023** 1 Yes ☐	**123**		**163**		
Northwest Territories	**025** 1 Yes ☐	**125**		**165**		
Nunavut	**026** 1 Yes ☐	**126**		**166**		
Outside Canada	**027** 1 Yes ☐	**127**		**167**		
Total		**129** G		**169** H		

* "Permanent establishment" is defined in Regulation 400(2).

** If the corporation has income or loss from an international banking centre: the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act*. This does not apply to tax years starting after March 20, 2013.

*** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits

Ontario basic income tax (from Schedule 500)	270				
Deduct: Ontario small business deduction (from Schedule 500)	402				
Subtotal			►		A6
Add:					
Ontario additional tax re Crown royalties (from Schedule 504)	274				
Ontario transitional tax debits (from Schedule 506)	276				
Recapture of Ontario research and development tax credit (from Schedule 508)	277				
Subtotal			►		B6
Subtotal (amount A6 **plus** amount B6)					C6
Deduct:					
Ontario resource tax credit (from Schedule 504)	404				
Ontario tax credit for manufacturing and processing (from Schedule 502)	406				
Ontario foreign tax credit (from Schedule 21)	408				
Ontario credit union tax reduction (from Schedule 500)	410				
Ontario transitional tax credits (from Schedule 506)	414				
Ontario political contributions tax credit (from Schedule 525)	415				
Subtotal			►		D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")					E6
Deduct: Ontario research and development tax credit (from Schedule 508)				416	
Ontario corporate income tax payable before Ontario corporate minimum tax credit and Ontario community food program donation tax credit for farmers (amount E6 **minus** amount on line 416) (if negative, enter "0")					F6
Deduct:					
Ontario corporate minimum tax credit (from Schedule 510)				418	
Ontario community food program donation tax credit for farmers (from Schedule 2)				420	
Ontario corporate income tax payable (amount F6 **minus** amounts on line 418 and line 420) (if negative, enter "0")					G6
Add:					
Ontario corporate minimum tax (from Schedule 510)	278	23,460			
Ontario special additional tax on life insurance corporations (from Schedule 512)	280				
Subtotal		23,460	►	23,460	H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)				23,460	I6
Deduct:					
Ontario qualifying environmental trust tax credit	450				
Ontario co-operative education tax credit (from Schedule 550)	452				
Ontario apprenticeship training tax credit (from Schedule 552)	454				
Ontario computer animation and special effects tax credit (from Schedule 554)	456				
Ontario film and television tax credit (from Schedule 556)	458				
Ontario production services tax credit (from Schedule 558)	460				
Ontario interactive digital media tax credit (from Schedule 560)	462				
Ontario sound recording tax credit (from Schedule 562)	464				
Ontario book publishing tax credit (from Schedule 564)	466				
Ontario innovation tax credit (from Schedule 566)	468				
Ontario business-research institute tax credit (from Schedule 568)	470				
Subtotal			►		J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255.				290 23,460	K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits	**255**	23,460

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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Schedule 8

Capital Cost Allowance (CCA)

Corporation's name	Business Number	Tax year end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2014-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under *Regulation* 1101(5q)? **101** 1 Yes ☐ 2 No ☒

	1 Class number (See Note) **200**	Description	2 Undepreciated capital cost at the beginning of the year (amount from column 12 of last year's schedule 8) **201**	3 Cost of acquisitions during the year (new property must be available for use)* **203**	4 Adjustments and transfers** **205**	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) **207**	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** **211**	7 Reduced undepreciated capital cost	8 CCA rate % **** **212**	9 Recapture of capital cost allowance***** (line 107 of Schedule 1) **213**	10 Terminal loss (line 404 of Schedule 1) **215**	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ****** **217**	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) **220**
1.	1		26,109,596			0		26,109,596	4	0	0	1,044,384	25,065,212
2.	47		32,124,141	6,302,637		0	3,151,319	35,275,459	8	0	0	2,822,037	35,604,741
3.	8	Smart meters	3,210,783	106,760		0	53,380	3,264,163	20	0	0	652,833	2,664,710
4.	1	New Building	23,384,078	244,855		0	122,428	23,506,505	4	0	0	940,260	22,688,673
		Totals	84,828,598	6,654,252			3,327,127	88,155,723				5,459,514	86,023,336

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed.
Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see *Regulation* 1100(2) and (2.2).

** Enter in column 4, "Adjustments and transfers", amounts that increase or reduce the undepreciated capital cost.
Items that **increase** the undepreciated capital cost include amounts transferred under section 85, or transferred on amalgamation or winding-up of a subsidiary. Items that **reduce** the undepreciated capital cost include government assistance received or entitled to be received in the year, or a reduction of capital cost after the application of section 80. See the *T2 Corporation Income Tax Guide* for other examples of adjustments and transfers to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments and transfers from column 4.
For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** Enter a rate only if you are using the declining balance method. For any other method (for example the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** For every entry in column 9, the "Recapture of capital cost allowance" there must be a corresponding entry in column 5, "Proceeds of dispositions during the year". The recapture and terminal loss rules do not apply to passenger vehicles in Class 10.1.

****** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

T2 SCH 8 (14)

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2014-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	PUC Inc		89839 7518 RC0001	1					
2.	PUC Services Inc		87626 3526 RC0002	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

T2 SCH 9 (11)

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2014-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter “0”)			200	3,112,065	A
Add: Cost of eligible capital property acquired during the taxation year	222				
Other adjustments	226				
Subtotal (line 222 plus line 226)		x 3 / 4 =			B
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002	228	x 1 / 2 =			C
amount B minus amount C (if negative, enter "0")			▶		D
Amount transferred on amalgamation or wind-up of subsidiary			224		E
Subtotal (add amounts A, D, and E)			230	3,112,065	F
Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year	242		G		
The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7)	244		H		
Other adjustments	246		I		
(add amounts G,H, and I)		x 3 / 4 =	248		J
Cumulative eligible capital balance (amount F minus amount J)				3,112,065	K
(if amount K is negative, enter "0" at line M and proceed to Part 2)					
Cumulative eligible capital for a property no longer owned after ceasing to carry on that business		249			
amount K	3,112,065				
less amount from line 249					
Current year deduction	3,112,065	x 7.00 % = 250	217,845 *		
(line 249 plus line 250) (enter this amount at line 405 of Schedule 1)			217,845 ▶	217,845	L
Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0")			300	2,894,220	M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount) . . . . N

Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988 . . . . **400** 1

Total of all amounts which reduced CEC in the current or prior years under subsection 80(7) . . **401** 2

Total of CEC deductions claimed for taxation years beginning before July 1, 1988 . . . . **402** 3

Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988 . . . **408** 4

Line 3 minus line 4 (if negative, enter "0") . . . . ▶ 5

Total of lines 1, 2 and 5 6

Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400 7

Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000 8

Subtotal (line 7 plus line 8) **409** ▶ 9

Line 6 minus line 9 (if negative, enter "0") . . . . ▶ O

Line N minus line O (if negative, enter "0") . . . . P

Line 5 x 1 / 2 = Q

Line P minus line Q (if negative, enter "0") . . . . R

Amount R x 2 / 3 = S

Amount N or amount O, whichever is less . . . . T

Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1) **410**

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SCHEDULE 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)
2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 – Associated non-CCPC
5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2006	maximum $300,000
2007	$300,001 to $400,000

Calendar year	Acceptable range
2008	maximum $400,000
2009	$400,001 to $500,000

If the calendar year to which this agreement applies is after 2009, ensure that the total at line A does not exceed $500,000.

Allocating the business limit

Date filed (do not use this area) . . . . **025** Year Month Day

Enter the calendar year to which the agreement applies . . . . **050** Year 2014

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . **075** 1 Yes ☐ 2 No ☒

	1 Names of associated corporations **100**	2 Business Number of associated corporations **200**	3 Association code **300**	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % **350**	6 Business limit allocated* $ **400**	
1	PUC Distribution Inc.	86709 6778 RC0001	1	500,000			
2	PUC Inc	89839 7518 RC0001	1	500,000	100.0000	500,000	
3	PUC Services Inc	87626 3526 RC0002	1	500,000			
				Total	100.0000	500,000	**A**

Business limit reduction under subsection 125(5.1) of the ITA

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. If the tax year straddles January 1, 2009, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year, if $500,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

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Schedule 33

Taxable Capital Employed in Canada – Large Corporations

Corporation's name	Business number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2014-12-31

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- If the total taxable capital employed in Canada of the corporation and its related corporations is greater than $10,000,000, file a completed Schedule 33 with your T2 Corporation Income Tax Return no later than six months from the end of the tax year.
- Unless otherwise noted, all legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms **financial institution**, **long-term debt**, and **reserves**.
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, **Taxable capital employed in Canada**.

Part 1 – Capital

Add the following year-end amounts:

Reserves that have not been deducted in computing income for the year under Part I	101			
Capital stock (or members' contributions if incorporated without share capital)	103	20,062,107		
Retained earnings	104	7,548,125		
Contributed surplus	105			
Any other surpluses	106			
Deferred unrealized foreign exchange gains	107			
All loans and advances to the corporation	108	1,918,747		
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109	66,917,609		
Any dividends declared but not paid by the corporation before the end of the year	110			
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111			
The total of all amounts, each of which is an amount under paragraph 181.2(3)(g) for a partnership in which the corporation held a membership interest at the end of the year, either directly or indirectly through another partnership (see note below)	112			
Subtotal (**add** lines 101 to 112)		96,446,588 ►	96,446,588	A

Deduct the following amounts:

Deferred tax debit balance at the end of the year	121			
Any deficit deducted in computing its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122			
Any amount deducted under subsection 135(1) in computing income under Part I for the year, as long as the amount may reasonably be regarded as being included in any of lines 101 to 112 above	123			
Deferred unrealized foreign exchange losses at the end of the year	124			
Subtotal (**add** lines 121 to 124)		►		B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")		190	96,446,588	

Note: Line 112 is determined as follows:

- – An amount for a partnership is the proportion of the amount, if any, by which the total of those amounts—for the partnership's last fiscal period that ends at or before the tax year-end of the corporation—that would be determined for lines 101, 107, 108, 109, and 111 as if they apply to the partnership in the same way that they apply to corporations exceed the partnership's deferred unrealized foreign exchange losses at the end of the fiscal period.
- – In determining an amount for a partnership, do not include amounts owing by the partnership
  - – to any corporation that held a membership interest in the partnership either directly or indirectly through another partnership.
  - – to any partnership in which a corporation described above held a membership interest either directly or indirectly through another partnership.
- – The proportion of an amount for a partnership is determined by the amount that the corporation's share of the partnership's income or loss for the fiscal period—to which the corporation is entitled either directly or indirectly through another partnership—is of the partnership's income or loss for the period.

Part 2 – Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend payable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim or similar obligation of, a partnership each member of which was, throughout the year, another corporation (other than a financial institution) that was not exempt from tax under this Part (otherwise than because of paragraph 181.1(3)(d)), or another partnership described in paragraph 181.2(4)(d.1).	406	
An interest in a partnership (see note 2 below)	407	
Investment allowance for the year (add lines 401 to 407)	490	

Notes:

1. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 (other than a non-resident corporation that at no time in the year carried on business in Canada through a permanent establishment).
2. Where the corporation has an interest in a partnership held either directly or indirectly through another partnership, refer to subsection 181.2(5) for additional rules regarding the carrying value of an interest in a partnership.
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation, refer to to subsection 181.2(6) for special rules that may apply.

Part 3 – Taxable capital

Capital for the year (line 190)		96,446,588	C
Deduct: Investment allowance for the year (line 490)			D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	96,446,588	

Part 4 – Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500)	96,446,588	x	Taxable income earned in Canada	610	1,000	= **Taxable capital employed in Canada**	690 96,446,588
			Taxable income		1,000		

Notes:
1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada			701		
Deduct the following amounts:					
Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada	711				
Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada	712				
Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below)	713				
Total deductions (**add** lines 711, 712, and 713)			▶		E
Taxable capital employed in Canada (line 701 **minus** amount E) (if negative, enter "0")			790		

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 – Calculation for purposes of the small business deduction

This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (line 690 or 790, whichever applies)		F
Deduct:	10,000,000	G
Excess (amount F **minus** amount G) (if negative, enter "0")		H
Calculation for purposes of the small business deduction (amount H x 0.225%)		I

Enter this amount at line 415 of the T2 return.

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2014-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

		Provide only one number per shareholder				
	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) **100**	Business Number (If a corporation is not registered, enter "NR") **200**	Social insurance number **300**	Trust number **350**	Percentage common shares **400**	Percentage preferred shares **500**
1	PUC Inc	89839 7518 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

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Schedule 510

Ontario Corporate Minimum Tax

Corporation's name	Business number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2014-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	111,320,233
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	88,036,121
Total assets (total of lines 112 to 116)		199,356,354
Total revenue of the corporation for the tax year **	142	91,011,407
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	18,686,464
Total revenue (total of lines 142 to 146)		109,697,871

The corporation is subject to CMT if:

- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**

- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**

- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Adjusted net income/loss for CMT purposes

Net income/loss per financial statements *			210	1,147,469	
Add (to the extent reflected in income/loss):					
Provision for current income taxes/cost of current income taxes	220				
Provision for deferred income taxes (debits)/cost of future income taxes	222				
Equity losses from corporations	224				
Financial statement loss from partnerships and joint ventures	226				
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230				
Other additions (see note below):					
Share of adjusted net income of partnerships and joint ventures **	228				
Total patronage dividends received, not already included in net income/loss	232				
281	282				
283	284				
Subtotal			▶		A
Deduct (to the extent reflected in income/loss):					
Provision for recovery of current income taxes/benefit of current income taxes	320	278,563			
Provision for deferred income taxes (credits)/benefit of future income taxes	322				
Equity income from corporations	324				
Financial statement income from partnerships and joint ventures	326				
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330				
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332				
Gain on donation of listed security or ecological gift	340				
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342				
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344				
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346				
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348				
Other deductions (see note below):					
Share of adjusted net loss of partnerships and joint ventures **	328				
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334				
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336				
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338				
381	382				
383	384				
385	386				
387	388				
389	390				
Subtotal		278,563	▶	278,563	B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)			490	868,906	

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

- exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
- include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

- Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

- Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.
- Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.
- Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive)		515	868,906	
Deduct:				
CMT loss available (amount R from Part 7)				
Minus: Adjustment for an acquisition of control *	518			
Adjusted CMT loss available		▶		C
Net income subject to CMT calculation (if negative, enter "0")		520	868,906	

Amount from line 520 868,906 x (Number of days in the tax year before July 1, 2010 ____ / Number of days in the tax year 365) x 4 % = ____ 1

Amount from line 520 868,906 x (Number of days in the tax year after June 30, 2010 365 / Number of days in the tax year 365) x 2.7 % = 23,460 2

Subtotal (amount 1 **plus** amount 2) 23,460 3

Gross CMT: amount on line 3 above x OAF **	540	23,460	
Deduct:			
Foreign tax credit for CMT purposes ***	550		
CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0")		23,460	D
Deduct:			
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)			
Net CMT payable (if negative, enter "0")		23,460	E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** ____ = ____

Ontario allocation factor 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000".

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year *		45,700	G			
Deduct:						
CMT credit expired *	600					
CMT credit carryforward at the beginning of the current tax year * (see note below)		45,700	▶	620	45,700	
Add:						
CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below)				650		
CMT credit available for the tax year (amount on line 620 **plus** amount on line 650)					45,700	H
Deduct:						
CMT credit deducted in the current tax year (amount P from Part 5)						I
Subtotal (amount H **minus** amount I)					45,700	J
Add:						
Net CMT payable (amount E from Part 3)		23,460				
SAT payable (amount O from Part 6 of Schedule 512)						
Subtotal		23,460	▶		23,460	K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)				670	69,160	L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:

- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)					45,700	M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)				1		
For a corporation that is not a life insurance corporation:						
CMT after foreign tax credit deduction (amount D from Part 3)	23,460	2				
For a life insurance corporation:						
Gross CMT (line 540 from Part 3)		3				
Gross SAT (line 460 from Part 6 of Schedule 512)		4				
The **greater** of amounts 3 and 4		5				
Deduct: line 2 or line 5, whichever applies:			23,460	6		
Subtotal (if negative, enter "0")				▶		N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)						
Deduct:						
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5)						
Subtotal (if negative, enter "0")				▶		O
CMT credit deducted in the current tax year (least of amounts M, N, and O)						P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? **675** 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	CMT credit balance *
10th previous tax year	**680**
9th previous tax year	**681**
8th previous tax year	**682**
7th previous tax year	**683**
6th previous tax year	**684**
5th previous tax year	**685**
4th previous tax year	**686**
3rd previous tax year	**687**
2nd previous tax year	**688**
1st previous tax year	**689**
Total **	

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . ______ Q

Deduct:

CMT loss expired * . . . . **700** ______

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . ______ ► **720** ______

Add:

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) . . . . **750** ______

CMT loss available (line 720 **plus** line 750) . . . . ______ R

Deduct:

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . . ______

Subtotal (if negative, enter "0") ______ S

Add:

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) . . . . **760** ______

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . **770** ______ T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:

- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	**810**	**820**
9th previous tax year	**811**	**821**
8th previous tax year	**812**	**822**
7th previous tax year	**813**	**823**
6th previous tax year	**814**	**824**
5th previous tax year	**815**	**825**
4th previous tax year	**816**	**826**
3rd previous tax year	**817**	**827**
2nd previous tax year	**818**	**828**
1st previous tax year		**829**
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

Canada Revenue Agency | Agence du revenu du Canada

SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2014-12-31

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations **200**	Business number (Canadian corporation only) (see Note 1) **300**	Total assets* (see Note 2) **400**	Total revenue** (see Note 2) **500**
1	PUC Inc	89839 7518 RC0001	63,409,164	2,408,252
2	PUC Services Inc	87626 3526 RC0002	24,626,957	16,278,212
		Total	**450** 88,036,121	**550** 18,686,464

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter ¨NR¨ if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

*** Rules for total assets**

- Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
- Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

**** Rules for total revenue**

- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
- Include the associated corporation's share of the total revenue of partnerships and joint ventures.
- If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

T2 SCH 511

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2014-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
PUC Distribution Inc.

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent Ontario	**110** Date of incorporation or amalgamation, whichever is the most recent Year Month Day 2000-02-18	**120** Ontario Corporation No. 1800173

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

200 Care of (if applicable)

210 Street number 765	**220** Street name/Rural route/Lot and Concession number Queen Street	**230** Suite number

240 Additional address information if applicable (line 220 must be completed first)

250 Municipality (e.g., city, town) Sault Ste Marie	**260** Province/state ON	**270** Country CA	**280** Postal/zip code P6A 6P2

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

300 1 If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 Greco (Last name) **451** Terry (First name)

454 ______________________, (Middle name(s))

460 2 Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 ☐ Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)

520 Street number	**530** Street name/Rural route/Lot and Concession number	**540** Suite number

550 Additional address information if applicable (line 530 must be completed first)

560 Municipality (e.g., city, town)	**570** Province/state	**580** Country	**590** Postal/zip code

Part 6 – Language of preference

600 ☐ Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

Financial Statements of

PUC DISTRIBUTION INC.

Year ended December 31, 2014

KPMG LLP
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, 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

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

Liabilities and Shareholder's Equity

	2014	2013
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.

Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2016-12-31

Business number 86709 6778 RC0001

The following is a list of federal instalments payable for the current taxation year. The last column indicates the instalments payable to Canada Revenue Agency. The instalments are due no later than on the dates indicated, otherwise non-deductible interest will be charged. Payment may be made by cheque or money order payable to the Receiver General either at an authorized financial institution or filed with **the appropriate remittance voucher at the following address**:

Canada Revenue Agency
875 Heron Road
Ottawa ON K1A 1B1

Note that you may also be able to pay by telephone or Internet banking. For more information, consult the *Corporation Instalment Guide*.

Monthly instalment workchart

Date	Monthly tax instalments	Refund transferred to instalments	Instalments paid	Cumulative difference	Instalments payable
2016-01-31	5,558				5,558
2016-02-29	5,558				5,558
2016-03-31	5,558				5,558
2016-04-30	5,558				5,558
2016-05-31	5,558				5,558
2016-06-30	5,558				5,558
2016-07-31	5,558				5,558
2016-08-31	5,558				5,558
2016-09-30	5,558				5,558
2016-10-31	5,558				5,558
2016-11-30	5,558				5,558
2016-12-31	5,551				5,551
Totals	66,689				66,689

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

200

055 **Do not use this area**

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act* and *Income Tax Regulations*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

Identification

Business number (BN) **001** 86709 6778 RC0001

Corporation's name

002 PUC Distribution Inc.

Address of head office

Has this address changed since the last time we were notified? . . . . **010** 1 Yes ☐ 2 No ☒

(If **yes**, complete lines 011 to 018.)

011 500 Second Line East

012

City **015** Sault Ste Marie

Province, territory, or state **016** ON

Country (other than Canada) **017**

Postal code/Zip code **018** P6B 4K1

Mailing address (if different from head office address)

Has this address changed since the last time we were notified? . . . . **020** 1 Yes ☐ 2 No ☒

(If **yes**, complete lines 021 to 028.)

021 c/o

022

023

City **025**

Province, territory, or state **026**

Country (other than Canada) **027**

Postal code/Zip code **028**

Location of books and records (if different from head office address)

Has the location of books and records changed since the last time we were notified? . . . . **030** 1 Yes ☐ 2 No ☒

(If **yes**, complete lines 031 to 038.)

031 500 Second Line East

032

City **035** Sault Ste Marie

Province, territory, or state **036** ON

Country (other than Canada) **037**

Postal code/Zip code **038** P6B 4K1

040 **Type of corporation at the end of the tax year**

1 ☐ Canadian-controlled private corporation (CCPC)

2 ☐ Other private corporation

3 ☐ Public corporation

4 ☐ Corporation controlled by a public corporation

5 ☒ Other corporation (specify, below)

Electrity Act

If the type of corporation changed during the tax year, provide the effective date of the change . . . . **043** ________ YYYY MM DD

To which tax year does this return apply?

Tax year start **060** 2015-01-01 YYYY MM DD

Tax year-end **061** 2015-12-31 YYYY MM DD

Has there been an acquisition of control to which subsection 249(4) applies since the tax year start on line 060? . . . . **063** 1 Yes ☐ 2 No ☒

If **yes**, provide the date control was acquired . . . . **065** ________ YYYY MM DD

Is the date on line 061 a deemed tax year-end according to subsection 249(3.1)? . . . . **066** 1 Yes ☐ 2 No ☒

Is the corporation a professional corporation that is a member of a partnership? . . . . **067** 1 Yes ☐ 2 No ☒

Is this the first year of filing after:

Incorporation? . . . . **070** 1 Yes ☐ 2 No ☒

Amalgamation? . . . . **071** 1 Yes ☐ 2 No ☒

If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . **072** 1 Yes ☐ 2 No ☒

If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . **076** 1 Yes ☐ 2 No ☒

Is this the final return up to dissolution? . . . . **078** 1 Yes ☐ 2 No ☒

If an election was made under section 261, state the functional currency used . . . . **079** ________

Is the corporation a resident of Canada?

080 1 Yes ☒ 2 No ☐ If **no**, give the country of residence on line 081 and complete and attach Schedule 97.

081 ________

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . **082** 1 Yes ☐ 2 No ☒

If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

085

1 ☐ Exempt under paragraph 149(1)(e) or (l)

2 ☐ Exempt under paragraph 149(1)(j)

3 ☐ Exempt under paragraph 149(1)(t)

4 ☐ Exempt under other paragraphs of section 149

Do not use this area

095 **096** **898**

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	**150**	☒	9
Is the corporation an associated CCPC?	**160**	☒	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	**161**	☐	49
Does the corporation have any non-resident shareholders who own voting shares?	**151**	☐	19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	**162**	☐	11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	**163**	☐	44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	**164**	☐	14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	**165**	☐	15
Is the corporation claiming a loss or deduction from a tax shelter?	**166**	☐	T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	**167**	☐	T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	**168**	☐	22
Did the corporation own any shares in one or more foreign affiliates in the tax year?	**169**	☐	25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the *Income Tax Regulations*?	**170**	☐	29
Did the corporation have a total amount over $1 million of reportable transactions with non-arm's length non-residents?	**171**	☐	T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	**173**	☒	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	**172**	☐	———
Does the corporation earn income from one or more Internet webpages or websites?	**180**	☐	88
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	**201**	☒	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	**202**	☐	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	**203**	☐	3
Is the corporation claiming any type of losses?	**204**	☒	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	**205**	☒	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	**206**	☐	6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	**207**	☐	7
Does the corporation have any property that is eligible for capital cost allowance?	**208**	☒	8
Does the corporation have any property that is eligible capital property?	**210**	☒	10
Does the corporation have any resource-related deductions?	**212**	☐	12
Is the corporation claiming deductible reserves (other than transitional reserves under section 34.2)?	**213**	☐	13
Is the corporation claiming a patronage dividend deduction?	**216**	☐	16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	**217**	☐	17
Is the corporation an investment corporation or a mutual fund corporation?	**218**	☐	18
Is the corporation carrying on business in Canada as a non-resident corporation?	**220**	☐	20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	**221**	☐	21
Does the corporation have any Canadian manufacturing and processing profits?	**227**	☐	27
Is the corporation claiming an investment tax credit?	**231**	☐	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	**232**	☐	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	**233**	☒	33/34/35
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	**234**	☒	———
Is the corporation claiming a surtax credit?	**237**	☐	37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	**238**	☐	38
Is the corporation claiming a Part I tax credit?	**242**	☐	42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	**243**	☐	43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	**244**	☐	45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	**249**	☐	46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	**250**	☐	39
Is the corporation claiming a Canadian film or video production tax credit refund?	**253**	☐	T1131
Is the corporation claiming a film or video production services tax credit refund?	**254**	☐	T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	**255**	☐	92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates in the tax year?	**271**	☐	T1134
Did the corporation own or hold specified foreign property where the total cost amount of all such property, at any time in the year, was more than CAN$100,000?	**259**	☐	T1135
Did the corporation transfer or loan property to a non-resident trust?	**260**	☐	T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	**261**	☐	T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	**262**	☐	T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	**263**	☐	T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	**264**	☐	T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	**265**	☐	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	**266**	☐	T2002
Has the corporation revoked any previous election made under subsection 89(11)?	**267**	☐	T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	**268**	☐	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	**269**	☐	54

Additional information

Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	**270**	1 Yes ☒	2 No ☐
Is the corporation inactive?	**280**	1 Yes ☐	2 No ☒

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electrical power distribution	**285**	100.000 %
286		**287**	%
288		**289**	%

Did the corporation immigrate to Canada during the tax year?	**291**	1 Yes ☐	2 No ☒
Did the corporation emigrate from Canada during the tax year?	**292**	1 Yes ☐	2 No ☒
Do you want to be considered as a quarterly instalment remitter if you are eligible?	**293**	1 Yes ☐	2 No ☐
If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible	**294**	YYYY MM DD	
If the corporation's major business activity is construction, did you have any subcontractors during the tax year?	**295**	1 Yes ☐	2 No ☐

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.			**300**	-682,792	A
Deduct: Charitable donations from Schedule 2	**311**				
Gifts to Canada, a province, or a territory from Schedule 2	**312**				
Cultural gifts from Schedule 2	**313**				
Ecological gifts from Schedule 2	**314**				
Gifts of medicine from Schedule 2	**315**				
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	**320**				
Part VI.1 tax deduction*	**325**				
Non-capital losses of previous tax years from Schedule 4	**331**				
Net capital losses of previous tax years from Schedule 4	**332**				
Restricted farm losses of previous tax years from Schedule 4	**333**				
Farm losses of previous tax years from Schedule 4	**334**				
Limited partnership losses of previous tax years from Schedule 4	**335**				
Taxable capital gains or taxable dividends allocated from a central credit union	**340**				
Prospector's and grubstaker's shares	**350**				
Subtotal			►		B
Subtotal (amount A **minus** amount B) (if negative, enter "0")					C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions			**355**		D
Taxable income (amount C **plus** amount D)			**360**		
Income exempt under paragraph 149(1)(t)			**370**		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)					Z

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 8.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 . . . . **400** ______ A

Taxable income from line 360 on page 3, **minus** 100/28 3.57143 of the amount on line 632* on page 7, **minus** 4 times the amount on line 636** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . . **405** ______ B

Business limit (see notes 1 and 2 below) . . . . **410** ______ C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.

2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C ______ x $\frac{\textbf{415}\ ^{***}\ 235{,}479\ \text{D}}{11{,}250}$ = ... ______ E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . **425** ______ F

Small business deduction

Amount A, B, C, or F, whichever is the least ______ x $\frac{\text{Number of days in the tax year before January 1, 2016} \quad 365}{\text{Number of days in the tax year} \quad 365}$ x 17 % = ______ 1

Amount A, B, C, or F, whichever is the least ______ x $\frac{\text{Number of days in the tax year after December 31, 2015, and before January 1, 2017} \quad \_\_\_}{\text{Number of days in the tax year} \quad 365}$ x 17.5 % = ______ 2

Total of amounts 1 and 2 (enter amount G on line I on page 7) **430** ______ G

***** Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

****** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

***** Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from page 3 (line 360 or amount Z, whichever applies) . . . . A

Lesser of amounts B9 and H9 from Part 9 of Schedule 27 . . . . B

Amount K13 from Part 13 of Schedule 27 C

Personal service business income . . . . **432** D

Amount used to calculate the credit union deduction (amount F from Schedule 17) . . . . E

Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . F

Aggregate investment income from line 440 on page 6* . . . . G

Subtotal (**add** amounts B to G) . . . . ► H

Amount A **minus** amount H (if negative, enter "0") I

General tax reduction for Canadian-controlled private corporations – Amount I **multiplied** by 13 % . . . . J

Enter amount J on line 638 on page 7.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies) . . . . K

Lesser of amounts B9 and H9 from Part 9 of Schedule 27 L

Amount K13 from Part 13 of Schedule 27 . . . . M

Personal service business income . . . . **434** N

Amount used to calculate the credit union deduction (amount F from Schedule 17) . . . . O

Subtotal (**add** amounts L to O) . . . . ► P

Amount K **minus** amount P (if negative, enter "0") . . . . Q

General tax reduction – Amount Q **multiplied** by 13 % . . . . R

Enter amount R on line 639 on page 7.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 . . . . **440** ______ x (26 2 / 3 + 4 x ______ (Number of days in the tax year after 2015) / 365 (Number of days in the tax year)) % = ______ A

Foreign non-business income tax credit from line 632 on page 7 . . . . ______ B

Deduct:
Foreign investment income from Schedule 7 . . . . . **445** ______ x (9 1 / 3 – 1 1 / 3 x ______ (Number of days in the tax year after 2015) / 365 (Number of days in the tax year)) % = ______ C

(if negative, enter "0") ______ ▶ ______ D

Amount A **minus** amount D (if negative, enter "0") . . . . ______ E

Taxable income from line 360 on page 3 . . . . ______ F

Deduct:
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . ______ G
Foreign non-business income tax credit from line 632 on page 7 . . . . ______ x 100 / 35 = ______ H
Foreign business income tax credit from line 636 on page 7 . . . . ______ x 4 = ______ I
Subtotal ______ ▶ ______ J
______ K

x (26 2 / 3 + 4 x Number of days in the tax year after 2015 ______ / Number of days in the tax year 365) % = ______ L

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8) . . . . ______ M

Refundable portion of Part I tax – Amount E, L, or M, whichever is the least . . . . **450** ______ N

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year . . . . **460** ______
Deduct: Dividend refund for the previous tax year . . . . **465** ______
______ ▶ ______ O

Add the total of:
Refundable portion of Part I tax from line 450 above . . . . ______ P
Total Part IV tax payable from Schedule 3 . . . . ______ Q
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation . . . . **480** ______
______ ▶ ______ R

Refundable dividend tax on hand at the end of the tax year – Amount O **plus** amount R . . . . **485** ______

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3 . . . . ______ x [(1 / 3) + (5 x ______ (Number of days in the tax year after 2015) / 365 (Number of days in the tax year)) %] = ______ S

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . ______ T

Dividend refund – Amount S or T, whichever is less . . . . ______ U
Enter amount U on line 784 on page 8.

Part I tax

Base amount Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 %	**550**		A
Recapture of investment tax credit from Schedule 31	**602**		B

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6				C
Taxable income from line 360 on page 3		D		
Deduct:				
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least		E		
Net amount (amount D **minus** amount E)		▶		F

Refundable tax on CCPC's investment income –

$$\left(6\ 2/3 + 4 \times \frac{\text{Number of days in the tax year after 2015}\ \_\_\_\_}{365\ \text{Number of days in the tax year}} \right)\%$$ of whichever is less: amount C or amount F **604** ______ G

Subtotal (**add** amounts A, B, and G) ______ H

Deduct:

Small business deduction from line 430 on page 4			I
Federal tax abatement	**608**		
Manufacturing and processing profits deduction from Schedule 27	**616**		
Investment corporation deduction	**620**		
Taxed capital gains **624**			
Additional deduction – credit unions from Schedule 17	**628**		
Federal foreign non-business income tax credit from Schedule 21	**632**		
Federal foreign business income tax credit from Schedule 21	**636**		
General tax reduction for CCPCs from amount J on page 5	**638**		
General tax reduction from amount R on page 5	**639**		
Federal logging tax credit from Schedule 21	**640**		
Eligible Canadian bank deduction under section 125.21	**641**		
Federal qualifying environmental trust tax credit	**648**		
Investment tax credit from Schedule 31	**652**		
Subtotal		▶	J

Part I tax payable – Amount H **minus** amount J ______ K
Enter amount K on line 700 on page 8.

Privacy statement

Personal information is collected under the *Income Tax Act* to administer tax, benefits, and related programs. It may also be used for any purpose related to the administration or enforcement of the Act such as audit, compliance and the payment of debts owed to the Crown. It may be shared or verified with other federal, provincial/territorial government institutions to the extent authorized by law. Failure to provide this information may result in interest payable, penalties or other actions. Under the *Privacy Act*, individuals have the right to access their personal information and request correction if there are errors or omissions. Refer to Info Source **http://www.cra-arc.gc.ca/gncy/tp/nfsrc/nfsrc-eng.html**, personal information bank CRA PPU 047.

Summary of tax and credits

Federal tax

Part I tax payable from amount K on page 7	700	
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		

Add provincial or territorial tax:

Provincial or territorial jurisdiction **750** ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	66,689	
Total tax payable	770	66,689	A

Deduct other credits:

Investment tax credit refund from Schedule 31	780			
Dividend refund from amount U on page 6	784			
Federal capital gains refund from Schedule 18	788			
Federal qualifying environmental trust tax credit refund	792			
Canadian film or video production tax credit refund (Form T1131)	796			
Film or video production services tax credit refund (Form T1177)	797			
Tax withheld at source	800			
Total payments on which tax has been withheld	801			
Provincial and territorial capital gains refund from Schedule 18	808			
Provincial and territorial refundable tax credits from Schedule 5	812			
Tax instalments paid	840	49,428		
Total credits	890	49,428 ▶	49,428	B

Refund code **894** ☐ Overpayment ______

Balance (amount A **minus** amount B) 17,261

If the result is positive, you have a **balance unpaid**.
If the result is negative, you have an **overpayment**.
Enter the amount on whichever line applies.
Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid 17,261

For information on how to make your payment, go to **www.cra-arc.gc.ca/payments**.

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information

910 ______ Branch number

914 ______ Institution number

918 ______ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? **896** 1 Yes ☐ 2 No ☒

If this return was prepared by a tax preparer for a fee, provide their EFILE number **920** D4481

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Certification

I, **950** Greco **951** Terry **954** Vice-President,
Last name (print) First name (print) Position, office, or rank

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2016-05-27
Date (yyyy/mm/dd)

Signature of the authorized signing officer of the corporation

956 (705) 759-6566
Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below **957** 1 Yes ☒ 2 No ☐

958 ______ Name (print)

959 ______ Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français.

990 1

Schedule of Instalment Remittances

Name of corporation contact

Telephone number

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
	Instalments	49,428

Total amount of instalments claimed (carry the result to line 840 of the T2 Return) 49,428 **A**

Total instalments credited to the taxation year per T9 49,428 **B**

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

Canada Revenue Agency Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2015-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	22,442,698	23,870,944
	Total tangible capital assets	2008	+	95,032,119	140,656,186
	Total accumulated amortization of tangible capital assets	2009	–	7,722,548	56,377,657
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	1,523,643	2,885,575
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	111,275,912	111,035,048
	Liabilities				
	Total current liabilities	3139	+	24,894,625	31,061,983
	Total long-term liabilities	3450	+	58,168,239	52,648,018
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	83,062,864	83,710,001
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	28,213,048	27,610,232
	Total liabilities and shareholder equity	3640	=	111,275,912	111,320,233
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	8,150,941	7,548,125

***** Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Canada Revenue Agency　Agence du revenu du Canada

SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2015-12-31

Income statement information

Description **GIFI**

Operating name **0001**
Description of the operation **0002**
Sequence number **0003** 01

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+	95,999,589	86,859,902
	Cost of sales	8518	–	73,275,057	70,473,134
	Gross profit/loss	8519	=	22,724,532	16,386,768
	Cost of sales	8518	+	73,275,057	70,473,134
	Total operating expenses	9367	+	19,280,154	19,669,367
	Total expenses (mandatory field)	9368	=	92,555,211	90,142,501
	Total revenue (mandatory field)	8299	+	99,666,851	91,011,407
	Total expenses (mandatory field)	9368	–	92,555,211	90,142,501
	Net non-farming income	9369	=	7,111,640	868,906
	Farming income statement information				
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	7,111,640	868,906
	Total other comprehensive income	9998	=	-4,641,680	
	Extraordinary items and income (linked to Schedule 140)				
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–	1,285,959	-278,563
	Future (deferred) income tax provision	9995	–	296,000	
	Total – Other comprehensive income	9998	+	-4,641,680	
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	888,001	1,147,469

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Canada Revenue Agency Agence du revenu du Canada

Schedule 141

Notes Checklist

Corporation's name	Business number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2015-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the **accountant**) who prepared or reported on the financial statements. If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and T4012, *T2 Corporation – Income Tax Guide.*
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? . . . . . **095** 1 Yes ☒ 2 No ☐

Is the accountant connected* with the corporation? . . . . . **097** 1 Yes ☐ 2 No ☒

Note
If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you **do have** to complete Part 4, as applicable.

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: **198**

Completed an auditor's report . . . . . 1 ☒

Completed a review engagement report . . . . . 2 ☐

Conducted a compilation engagement . . . . . 3 ☐

Part 3 – Reservations

If you selected option 1 or 2 under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . . . **099** 1 Yes ☐ 2 No ☒

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: **110**

Prepared the tax return (financial statements prepared by client) . . . . . 1 ☐

Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . . . 2 ☐

Were notes to the financial statements prepared? . . . . . **101** 1 Yes ☒ 2 No ☐

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes? . . . . . **104** 1 Yes ☐ 2 No ☒

Is re-evaluation of asset information mentioned in the notes? . . . . . **105** 1 Yes ☐ 2 No ☒

Is contingent liability information mentioned in the notes? . . . . . **106** 1 Yes ☒ 2 No ☐

Is information regarding commitments mentioned in the notes? . . . . . **107** 1 Yes ☐ 2 No ☒

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . **108** 1 Yes ☐ 2 No ☒

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . **200** 1 Yes ☐ 2 No ☒

If **yes**, enter the amount recognized:

		In net income Increase (decrease)		In OCI Increase (decrease)
Property, plant, and equipment	**210**		**211**	
Intangible assets	**215**		**216**	
Investment property	**220**			
Biological assets	**225**			
Financial instruments	**230**		**231**	
Other	**235**		**236**	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? . . . . . **250** 1 Yes ☐ 2 No ☒

Did the corporation apply hedge accounting during the tax year? . . . . . **255** 1 Yes ☐ 2 No ☒

Did the corporation discontinue hedge accounting during the tax year? . . . . . **260** 1 Yes ☐ 2 No ☒

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . **265** 1 Yes ☒ 2 No ☐

If **yes**, you have to maintain a separate reconciliation.

SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2015-12-31

Assets – lines 1000 to 2599

1000	3,084,294	**1060**	5,900,335	**1062**	10,862,168
1120	1,493,197	**1400**	436,883	**1483**	603,021
1484	62,800	**1599**	22,442,698	**1600**	858,085
1680	25,018,700	**1681**	-1,303,872	**1740**	16,843,342
1741	-1,198,845	**1785**	52,311,992	**1786**	-5,219,831
2008	95,032,119	**2009**	-7,722,548	**2420**	439,643
2421	1,084,000	**2589**	1,523,643	**2599**	111,275,912

Liabilities – lines 2600 to 3499

2620	7,958,726	**2770**	228,455	**2920**	15,785,022
2961	922,422	**3139**	24,894,625	**3145**	23,846,498
3220	1,119,671	**3260**	26,534,040	**3320**	6,668,030
3450	58,168,239	**3499**	83,062,864		

Shareholder equity – lines 3500 to 3640

3500	20,062,107	**3600**	8,150,941	**3620**	28,213,048
3640	111,275,912				

Retained earnings – lines 3660 to 3849

3660	7,548,125	**3680**	5,529,681	**3720**	-285,185
3740	-4,641,680	**3849**	8,150,941		

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2015-12-31

Description

Sequence number **0003** 01

Other comprehensive income – lines 7000 to 7020

7020	-4,641,680

Revenue – lines 8000 to 8299

8000	95,999,589	**8089**	95,999,589	**8090**	26,460
8230	3,640,802	**8299**	99,666,851		

Cost of sales – lines 8300 to 8519

8320	73,275,057	**8518**	73,275,057	**8519**	22,724,532

Operating expenses – lines 8520 to 9369

8523	6,324	**8670**	4,139,746	**8714**	3,003,913
8717	1,417,758	**9270**	1,529,216	**9273**	5,977,598
9284	3,205,599	**9367**	19,280,154	**9368**	92,555,211
9369	7,111,640				

Extraordinary items and taxes – lines 9970 to 9999

9970	7,111,640	**9990**	1,285,959	**9995**	296,000
9998	-4,641,680	**9999**	888,001		

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

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Net Income (Loss) for Income Tax Purposes

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2015-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125				888,001	A
Add:					
Provision for income taxes – current	101	1,285,959			
Provision for income taxes – deferred	102	296,000			
Amortization of tangible assets	104	4,139,746			
Loss on disposal of assets	111	242,287			
Non-deductible meals and entertainment expenses	121	3,162			
Subtotal of additions		5,967,154	▶	5,967,154	
Other additions:					
Taxable/non-deductible other comprehensive income items	239	4,641,680			
Miscellaneous other additions:					
604					
Total	294				
Subtotal of other additions	199	4,641,680	▶	4,641,680	
Total additions	500	10,608,834	▶	10,608,834	B
Amount A **plus** amount B				11,496,835	
Deduct:					
Capital cost allowance from Schedule 8	403	5,543,995			
Cumulative eligible capital deduction from Schedule 10	405	202,595			
Subtotal of deductions		5,746,590	▶	5,746,590	
Other deductions:					
Miscellaneous other deductions:					
700 Regulatory charges deferred for accounting purposes	390	6,433,037			
704					
Total	394				
Subtotal of other deductions	499	6,433,037	▶	6,433,037	
Total deductions	510	12,179,627	▶	12,179,627	
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				-682,792	

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Schedule 4

Corporation Loss Continuity and Application

Corporation's name	Business number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2015-12-31

- Use this form to determine the continuity and use of available losses; to determine a current-year non-capital loss, farm loss, restricted farm loss, or limited partnership loss; to determine the amount of restricted farm loss and limited partnership loss that can be applied in a year; and to ask for a loss carryback to previous years.
- A corporation can choose whether or not to deduct an available loss from income in a tax year. The corporation can deduct losses in any order. However, for each type of loss, deduct the oldest loss first.
- According to subsection 111(4) of the *Income Tax Act*, when control has been acquired, no amount of capital loss incurred for a tax year ending before that time is deductible in computing taxable income in a tax year ending after that time. Also, no amount of capital loss incurred in a tax year ending after that time is deductible in computing taxable income of a tax year ending before that time.
- When control has been acquired, subsection 111(5) provides for similar treatment of non-capital and farm losses, except as listed in paragraphs 111(5)(a) and (b).
- For information on these losses, see the *T2 Corporation – Income Tax Guide*.
- File one completed copy of this schedule with the T2 return, or send the schedule by itself to the tax centre where the return is filed.
- All legislative references are to the *Income Tax Act*.

Part 1 – Non-capital losses

Determination of current-year non-capital loss

Net income (loss) for income tax purposes				-682,792	A
Deduct: (increase a loss)					
Net capital losses deducted in the year (enter as a positive amount)			a		
Taxable dividends deductible under section 112 or subsections 113(1) or 138(6)			b		
Amount of Part VI.1 tax deductible			c		
Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2)			d		
Subtotal (total of amounts a to d)			▶		B
Subtotal (amount A **minus** amount B; if positive, enter "0")				-682,792	C
Deduct: (increase a loss)					
Section 110.5 or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions					D
Subtotal (amount C **minus** amount D)				-682,792	E
Add: (decrease a loss)					
Current-year farm loss (whichever is less: the net loss from farming or fishing included in the income, or the non-capital loss before deducting the farm loss)					F
Current-year non-capital loss (amount E **plus** amount F; if positive, enter "0")				-682,792	G

If amount G is negative, enter it on line 110 as a positive.

Continuity of non-capital losses and request for a carryback

Non-capital loss at the end of the previous tax year			e		
Deduct: Non-capital loss expired*	**100**		f		
Non-capital losses at the beginning of the tax year (amount e **minus** amount f)	**102**		▶		H
Add:					
Non-capital losses transferred on an amalgamation or the wind-up of a subsidiary corporation	**105**		g		
Current-year non-capital loss (from amount G)	**110**	682,792	h		
Subtotal (amount g **plus** amount h)		682,792	▶	682,792	I
Subtotal (amount H **plus** amount I)				682,792	J

* A non-capital loss expires as follows:
- after **10** tax years if it arose in a tax year ending after March 22, 2004, and before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

An allowable business investment loss becomes a net capital loss after **10** tax years if it arose in a tax year ending after March 22, 2004.

Part 1 – Non-capital losses (continued)

Deduct:

Other adjustments (includes adjustments for an acquisition of control)	150		i		
Section 80 – Adjustments for forgiven amounts	140		j		
Subsection 111(10) – Adjustments for fuel tax rebate			j.1		
Non-capital losses of previous tax years applied in the current tax year Enter amount k on line 331 of the T2 Return.	130		k		
Current and previous year non-capital losses applied against current-year taxable dividends subject to Part IV tax**	135		l		
Subtotal (total of amounts i to l)			▶		K
Non-capital losses before any request for a carryback (amount J **minus** amount K)				682,792	L

Deduct – **Request to carry back non-capital loss to:**

First previous tax year to reduce taxable income	901		m		
Second previous tax year to reduce taxable income	902		n		
Third previous tax year to reduce taxable income	903	682,792	o		
First previous tax year to reduce taxable dividends subject to Part IV tax	911		p		
Second previous tax year to reduce taxable dividends subject to Part IV tax	912		q		
Third previous tax year to reduce taxable dividends subject to Part IV tax	913		r		
Total of requests to carry back non-capital losses to previous tax years (total of amounts m to r)		682,792	▶	682,792	M
Closing balance of non-capital losses to be carried forward to future tax years (amount L **minus** amount M)	180				N

** Amount l is the total of lines 330 and 335 from Schedule 3, *Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation*.

Part 2 – Capital losses

Continuity of capital losses and request for a carryback

Capital losses at the end of the previous tax year	200		a		
Capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation	205		b		
Subtotal (amount a **plus** amount b)			▶		A
Deduct:					
Other adjustments (includes adjustments for an acquisition of control)	250		c		
Section 80 – Adjustments for forgiven amounts	240		d		
Subtotal (amount c **plus** amount d)			▶		B
Subtotal (amount A **minus** amount B)					C
Add: Current-year capital loss (from the calculation on Schedule 6, *Summary of Dispositions of Capital Property*)	210				D
Unused non-capital losses that expired in the tax year*			e		
Allowable business investment losses (ABIL) that expired as non-capital losses in the tax year**			f		
Enter amount e or f, whichever is less	215		g		
ABILs expired as non-capital loss: line 215 **divided** by 0.500000	220				E
Subtotal (total of amounts C to E)					F

Note
If there has been an amalgamation or a windup of a subsidiary, do a separate calculation of the ABIL expired as non-capital loss for each predecessor or subsidiary. Add all these amounts and enter the total on line 220 above.

* If the losses were incurred in a tax year ending after March 22, 2004, and before 2006, enter the losses from the 11th previous tax year. Enter the losses from the 21st previous tax year if the losses were incurred in a tax year ending after 2005. Enter the part that was not used in previous years and the current year on line e.

** If the losses were incurred in a tax year ending after March 22, 2004, enter the losses from the 11th previous tax year. Enter the full amount on line f.

Part 2 – Capital losses (continued)

Deduct: Capital losses from previous tax years applied against the current-year net capital gain*** . . . . **225** ______ G

Capital losses before any request for a carryback (amount F **minus** amount G) ______ H

Deduct – **Request to carry back capital loss to******:

	Capital gain (100%)		Amount carried back (100%)			
First previous tax year		**951**		h		
Second previous tax year		**952**		i		
Third previous tax year	37,523	**953**		j		
Subtotal (total of amounts h to j)				▶		I
Closing balance of capital losses to be carried forward to future tax years (amount H **minus** amount I)				**280**		J

*** To get the net capital losses required to reduce the taxable capital gain included in the net income (loss) for the purpose of current-year tax, enter the amount from line 225 **multiplied** by 50% on line 332 of the T2 return.

**** On line 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, **multiply** this amount by the 50% inclusion rate.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

Farm losses at the end of the previous tax year			a		
Deduct: Farm loss expired*	**300**		b		
Farm losses at the beginning of the tax year (amount a **minus** amount b)	**302**		▶		A
Add:					
Farm losses transferred on the amalgamation or the windup of a subsidiary corporation	**305**		c		
Current-year farm loss (amount F in Part 1)	**310**		d		
Subtotal (amount c **plus** amount d)			▶		B
Subtotal (amount A **plus** amount B)					C
Deduct:					
Other adjustments (includes adjustments for an acquisition of control)	**350**		e		
Section 80 – Adjustments for forgiven amounts	**340**		f		
Farm losses of previous tax years applied in the current tax year Enter amount g on line 334 of the T2 Return.	**330**		g		
Current and previous year farm losses applied against current-year taxable dividends subject to Part IV tax**	**335**		h		
Subtotal (total of amounts e to h)			▶		D
Farm losses before any request for a carryback (amount C **minus** amount D)					E
Deduct – **Request to carry back farm loss to:**					
First previous tax year to reduce taxable income	**921**		i		
Second previous tax year to reduce taxable income	**922**		j		
Third previous tax year to reduce taxable income	**923**		k		
First previous tax year to reduce taxable dividends subject to Part IV tax	**931**		l		
Second previous tax year to reduce taxable dividends subject to Part IV tax	**932**		m		
Third previous tax year to reduce taxable dividends subject to Part IV tax	**933**		n		
Subtotal (total of amounts i to n)			▶		F
Closing balance of farm losses to be carried forward to future tax years (amount E **minus** amount F)			**380**		G

* A farm loss expires as follows:
- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

** Amount h is the total of lines 340 and 345 from Schedule 3.

Part 4 – Restricted farm losses

Current-year restricted farm loss

Total losses for the year from farming business				**485**		A
Minus the deductible farm loss:						
(amount A above ______ – $2,500) **divided** by 2 =		a				
Amount a or $ 15,000 *, whichever is less		▶	b			
	2,500		c			
Subtotal (amount b **plus** amount c)	2,500	▶			2,500	B
Current-year restricted farm loss (amount A **minus** amount B)						C

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year			d			
Deduct: Restricted farm loss expired**	**400**		e			
Restricted farm losses at the beginning of the tax year (amount d **minus** amount e)	**402**			▶		D
Add:						
Restricted farm losses transferred on the amalgamation or the wind-up of a subsidiary corporation	**405**		f			
Current-year restricted farm loss (from amount C) Enter amount g on line 233 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*.	**410**		g			
Subtotal (amount f **plus** amount g)				▶		E
Subtotal (amount D **plus** amount E)						F
Deduct:						
Restricted farm losses from previous tax years applied against current farming income Enter amount h on line 333 of the T2 return.	**430**		h			
Section 80 – Adjustments for forgiven amounts	**440**		i			
Other adjustments	**450**		j			
Subtotal (total of amounts h to j)				▶		G
Restricted farm losses before any request for a carryback (amount F **minus** amount G)						H

Deduct – **Request to carry back restricted farm loss to:**

First previous tax year to reduce farming income	**941**		k			
Second previous tax year to reduce farming income	**942**		l			
Third previous tax year to reduce farming income	**943**		m			
Subtotal (total of amounts k to m)				▶		I
Closing balance of restricted farm losses to be carried forward to future tax years (amount H **minus** amount I)	**480**					J

Note

The total losses for the year from all farming businesses are calculated without including scientific research expenses.

* For tax years that end before March 21, 2013, use $6,250 instead of $15,000.

** A restricted farm loss expires as follows:
- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

Part 5 – Listed personal property losses

Continuity of listed personal property loss and request for a carryback

Listed personal property losses at the end of the previous tax year			a			
Deduct: Listed personal property loss expired after seven tax years	500		b			
Listed personal property losses at the beginning of the tax year (amount a **minus** amount b)	502		▶			A
Add: Current-year listed personal property loss (from Schedule 6)				510		B
Subtotal (amount A **plus** amount B)						C
Deduct:						
Previous year personal property losses applied in the current tax year against listed personal property gains	530		c			
Enter amount c on line 655 of Schedule 6.						
Other adjustments	550		d			
Subtotal (amount c **plus** amount d)			▶			D
Listed personal property losses remaining before any request for a carryback (amount C **minus** amount D)						E
Deduct – **Request to carry back listed personal property loss to:**						
First previous tax year to reduce listed personal property gains	961		e			
Second previous tax year to reduce listed personal property gains	962		f			
Third previous tax year to reduce listed personal property gains	963		g			
Subtotal (total of amounts e to g)			▶			F
Closing balance of listed personal property losses to be carried forward to future tax years (amount E **minus** amount F)				580		G

Part 7 – Limited partnership losses

Current-year limited partnership losses

1	2	3	4	5	6	7
Partnership identifier **600**	Tax year ending YYYY/MM/DD **602**	Corporation's share of limited partnership loss **604**	Corporation's at-risk amount **606**	Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses **608**	Column 4 **minus** column 5 (if negative, enter "0")	Current-year limited partnership losses (column 3 **minus** 6) **620**
					Total (enter this amount on line 222 of Schedule 1)	

Limited partnership losses from previous tax years that may be applied in the current year

1	2	3	4	5	6	7
Partnership identifier **630**	Tax year ending YYYY/MM/DD **632**	Limited partnership losses at the end of the previous tax year **634**	Corporation's at-risk amount **636**	Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses **638**	Column 4 **minus** column 5 (if negative, enter "0")	Limited partnership losses that may be applied in the year (the lesser of columns 3 and 6) **650**

Continuity of limited partnership losses that can be carried forward to future tax years

1	2	3	4	5	6
Partnership identifier **660**	Limited partnership losses at the end of the previous tax year **662**	Limited partnership losses transferred on an amalgamation or the windup of a subsidiary **664**	Current-year limited partnership losses (from line 620) **670**	Limited partnership losses applied in the current year (cannot be more than line 650) **675**	Current year limited partnership losses closing balance to be carried forward to future years (column 2 **plus** column 3 **plus** column 4 **minus** column 5) **680**
			Total (enter this amount on line 335 of the T2 return)		

Note

If you have any current–or previous–year losses, enter your partnership identifier on line 600, 630, or 660.

Part 8 – Election under paragraph 88(1.1)(f)

If you are making an election under paragraph 88(1.1)(f), check the box . . . . **190** Yes ☐

Further to a winding-up of a subsidiary, the portion of a non-capital loss, restricted farm loss, farm loss, or limited partnership loss from a wholly-owned subsidiary is deemed to be the loss of a parent from its tax year starting after the commencement of the winding-up.

Note

This election is only applicable for wind-ups under subsection 88(1) that are reported on Schedule 24, *First-Time Filer after Incorporation, Amalgamation, or Winding-up of a Subsidiary into a Parent*, and the deemed provision is only for the tax years that start after the commencement of the wind-up.

Non-Capital Loss Continuity Workchart

Part 6 – Analysis of balance of losses by year of origin

Non-capital losses – losses that can be carried forward over 20 years

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce		Balance at end of year
					Taxable income	Part IV tax	
Current	N/A	682,792		682,792	N/A		
1st preceding taxation year 2014-12-31		N/A		N/A			
2nd preceding taxation year 2013-12-31		N/A		N/A			
3rd preceding taxation year 2012-12-31		N/A		N/A			
4th preceding taxation year 2011-12-31		N/A		N/A			
5th preceding taxation year 2010-12-31		N/A		N/A			
6th preceding taxation year 2009-12-31		N/A		N/A			
7th preceding taxation year 2008-12-31		N/A		N/A			
8th preceding taxation year 2007-12-31		N/A		N/A			
9th preceding taxation year 2006-12-31		N/A		N/A			
10th preceding taxation year 2005-12-31		N/A		N/A			
11th preceding taxation year 2004-12-31		N/A		N/A			
12th preceding taxation year 2003-12-31		N/A		N/A			
13th preceding taxation year 2002-12-31		N/A		N/A			
14th preceding taxation year 2001-12-31		N/A		N/A			
15th preceding taxation year 2000-12-31		N/A		N/A			
16th preceding taxation year		N/A		N/A			
17th preceding taxation year		N/A		N/A			
18th preceding taxation year		N/A		N/A			
19th preceding taxation year		N/A		N/A			
20th preceding taxation year		N/A		N/A			*
Total		682,792		682,792			

* **This balance expires this year and will not be available next year.**

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Schedule 5

Tax Calculation Supplementary – Corporations

Corporation's name	Business Number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2015-12-31

- Use this schedule if, during the tax year, the corporation:
  - – had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - – is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - – has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations.*
- For more information, see the *T2 Corporation – Income Tax Guide.*
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 ______ Enter the Regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2*** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes ☐	103		143		
Newfoundland and Labrador Offshore	004 1 Yes ☐	104		144		
Prince Edward Island	005 1 Yes ☐	105		145		
Nova Scotia	007 1 Yes ☐	107		147		
Nova Scotia Offshore	008 1 Yes ☐	108		148		
New Brunswick	009 1 Yes ☐	109		149		
Quebec	011 1 Yes ☐	111		151		
Ontario	013 1 Yes ☐	113		153		
Manitoba	015 1 Yes ☐	115		155		
Saskatchewan	017 1 Yes ☐	117		157		
Alberta	019 1 Yes ☐	119		159		
British Columbia	021 1 Yes ☐	121		161		
Yukon	023 1 Yes ☐	123		163		
Northwest Territories	025 1 Yes ☐	125		165		
Nunavut	026 1 Yes ☐	126		166		
Outside Canada	027 1 Yes ☐	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).

** If the corporation has income or loss from an international banking centre: the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act*. This does not apply to tax years starting after March 20, 2013.

*** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits

Ontario basic income tax (from Schedule 500)	270			
Deduct: Ontario small business deduction (from Schedule 500)	402			
Subtotal			►	A6
Add:				
Ontario additional tax re Crown royalties (from Schedule 504)	274			
Ontario transitional tax debits (from Schedule 506)	276			
Recapture of Ontario research and development tax credit (from Schedule 508)	277			
Subtotal			►	B6
Subtotal (amount A6 **plus** amount B6)				C6
Deduct:				
Ontario resource tax credit (from Schedule 504)	404			
Ontario tax credit for manufacturing and processing (from Schedule 502)	406			
Ontario foreign tax credit (from Schedule 21)	408			
Ontario credit union tax reduction (from Schedule 500)	410			
Ontario transitional tax credits (from Schedule 506)	414			
Ontario political contributions tax credit (from Schedule 525)	415			
Subtotal			►	D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")				E6
Deduct: Ontario research and development tax credit (from Schedule 508)			416	
Ontario corporate income tax payable before Ontario corporate minimum tax credit and Ontario community food program donation tax credit for farmers (amount E6 **minus** amount on line 416) (if negative, enter "0")				F6
Deduct:				
Ontario corporate minimum tax credit (from Schedule 510)			418	
Ontario community food program donation tax credit for farmers (from Schedule 2)			420	
Ontario corporate income tax payable (amount F6 **minus** amounts on line 418 and line 420) (if negative, enter "0")				G6
Add:				
Ontario corporate minimum tax (from Schedule 510)	278	66,689		
Ontario special additional tax on life insurance corporations (from Schedule 512)	280			
Subtotal		66,689	►	66,689 H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)				66,689 I6
Deduct:				
Ontario qualifying environmental trust tax credit	450			
Ontario co-operative education tax credit (from Schedule 550)	452			
Ontario apprenticeship training tax credit (from Schedule 552)	454			
Ontario computer animation and special effects tax credit (from Schedule 554)	456			
Ontario film and television tax credit (from Schedule 556)	458			
Ontario production services tax credit (from Schedule 558)	460			
Ontario interactive digital media tax credit (from Schedule 560)	462			
Ontario sound recording tax credit (from Schedule 562)	464			
Ontario book publishing tax credit (from Schedule 564)	466			
Ontario innovation tax credit (from Schedule 566)	468			
Ontario business-research institute tax credit (from Schedule 568)	470			
Subtotal			►	J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255.			290	66,689 K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits **255** 66,689

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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Schedule 8

Capital Cost Allowance (CCA)

Corporation's name	Business Number	Tax year end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2015-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under *Regulation* 1101(5q)? **101** 1 Yes ☐ 2 No ☒

	1 Class number (See Note) **200**	Description	2 Undepreciated capital cost at the beginning of the year (amount from column 12 of last year's schedule 8) **201**	3 Cost of acquisitions during the year (new property must be available for use)* **203**	4 Adjustments and transfers** **205**	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) **207**	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** **211**	7 Reduced undepreciated capital cost	8 CCA rate % **** **212**	9 Recapture of capital cost allowance***** (line 107 of Schedule 1) **213**	10 Terminal loss (line 404 of Schedule 1) **215**	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ****** **217**	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) **220**
1.	1		25,065,212			0		25,065,212	4	0	0	1,002,608	24,062,604
2.	1	New Building	22,688,673			0		22,688,673	4	0	0	907,547	21,781,126
3.	8	Smart meters	2,664,710	52,944		0	26,472	2,691,182	20	0	0	538,236	2,179,418
4.	47		35,604,741	6,130,722		0	3,065,361	38,670,102	8	0	0	3,093,608	38,641,855
5.	1b	New Building Additions		66,532		0	33,266	33,266	6	0	0	1,996	64,536
		Totals	86,023,336	6,250,198			3,125,099	89,148,435				5,543,995	86,729,539

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed. Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see *Regulation* 1100(2) and (2.2).

** Enter in column 4, "Adjustments and transfers", amounts that increase or reduce the undepreciated capital cost. Items that **increase** the undepreciated capital cost include amounts transferred under section 85, or transferred on amalgamation or winding-up of a subsidiary. Items that **reduce** the undepreciated capital cost include government assistance received or entitled to be received in the year, or a reduction of capital cost after the application of section 80. See the *T2 Corporation Income Tax Guide* for other examples of adjustments and transfers to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments and transfers from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** Enter a rate only if you are using the declining balance method. For any other method (for example the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** For every entry in column 9, the "Recapture of capital cost allowance" there must be a corresponding entry in column 5, "Proceeds of dispositions during the year". The recapture and terminal loss rules do not apply to passenger vehicles in Class 10.1.

****** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

Tax return

Additions for tax purposes – Schedule 8 regular classes		6,250,198			
Additions for tax purposes – Schedule 8 leasehold improvements	+				
Operating leases capitalized for book purposes	+				
Capital gain deferred	+				
Recapture deferred	+				
Deductible expenses capitalized for book purposes – Schedule 1	+				
Other (specify):					
Deferred revenue reclassed to liabilities for FS purposes	+	1,119,671			
Topside adjustment to depreciation	+	110,389			
Rounding	+	2			
Total additions per books	=	7,480,260	▶		7,480,260
Proceeds up to original cost – Schedule 8 regular classes					
Proceeds up to original cost – Schedule 8 leasehold improvements	+				
Proceeds in excess of original cost – capital gain	+				
Recapture deferred – as above	+				
Capital gain deferred – as above	+				
Pre V-day appreciation	+				
Other (specify):					
IFRS adjustment to accumulated amortization	+	285,186			
Account 1576 accounting adjustment	+	72,876			
Total proceeds per books	=	358,062	▶	–	358,062
Depreciation and amortization per accounts – Schedule 1				–	4,139,746
Loss on disposal of fixed assets per accounts				–	242,287
Gain on disposal of fixed assets per accounts				+	
Net change per tax return				=	2,740,165

Financial statements

Fixed assets (excluding land) per financial statements

Closing net book value		86,451,486
Opening net book value	–	83,711,321
Net change per financial statements	=	2,740,165

If the amounts from the tax return and the financial statements differ, explain why below.

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2015-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name **100**	Country of residence (other than Canada) **200**	Business number (see note 1) **300**	Relationship code (see note 2) **400**	Number of common shares you own **500**	% of common shares you own **550**	Number of preferred shares you own **600**	% of preferred shares you own **650**	Book value of capital stock **700**
1.	PUC Inc		89839 7518 RC0001	1					
2.	PUC Services Inc		87626 3526 RC0002	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2015-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0") . . . . **200** 2,894,220 A

Add: Cost of eligible capital property acquired during the taxation year . . . . **222** ______

Other adjustments . . . . **226** ______

Subtotal (line 222 plus line 226) ______ x 3 / 4 = ______ B

Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 . . . . **228** ______ x 1 / 2 = ______ C

amount B minus amount C (if negative, enter "0") ______ ▶ ______ D

Amount transferred on amalgamation or wind-up of subsidiary . . . . **224** ______ E

Subtotal (add amounts A, D, and E) **230** 2,894,220 F

Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year . . . . **242** ______ G

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) . . . . **244** ______ H

Other adjustments . . . . **246** ______ I

(add amounts G,H, and I) ______ x 3 / 4 = **248** ______ J

Cumulative eligible capital balance (amount F minus amount J) . . . . 2,894,220 K

(if amount K is negative, enter "0" at line M and proceed to Part 2)

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business **249** ______

amount K 2,894,220

less amount from line 249 ______

Current year deduction . . . . 2,894,220 x 7.00 % = **250** 202,595 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 202,595 ▶ 202,595 L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") . . . . **300** 2,691,625 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)								N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988				400		1		
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)				401		2		
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402		3					
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408		4					
Line 3 minus line 4 (if negative, enter "0")			▶			5		
Total of lines 1, 2 and 5						6		
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400			7					
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000			8					
Subtotal (line 7 plus line 8)	409		▶			9		
Line 6 minus line 9 (if negative, enter "0")						▶		O
Line N minus line O (if negative, enter "0")								P
Line 5						x 1 / 2 =		Q
Line P minus line Q (if negative, enter "0")								R
Amount R						x 2 / 3 =		S
Amount N or amount O, whichever is less								T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)							410	

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SCHEDULE 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)
2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 – Associated non-CCPC
5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2006	maximum $300,000
2007	$300,001 to $400,000

Calendar year	Acceptable range
2008	maximum $400,000
2009	$400,001 to $500,000

If the calendar year to which this agreement applies is after 2009, ensure that the total at line A does not exceed $500,000.

Allocating the business limit

Date filed (do not use this area) . . . . . . **025** Year Month Day

Enter the calendar year to which the agreement applies . . . . . . **050** Year 2015

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . . **075** 1 Yes ☐ 2 No ☒

	1 Names of associated corporations **100**	2 Business Number of associated corporations **200**	3 Association code **300**	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % **350**	6 Business limit allocated* $ **400**	
1	PUC Distribution Inc.	86709 6778 RC0001	1	500,000			
2	PUC Inc	89839 7518 RC0001	1	500,000			
3	PUC Services Inc	87626 3526 RC0002	1	500,000	100.0000	500,000	
				Total	100.0000	500,000	**A**

Business limit reduction under subsection 125(5.1) of the ITA

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. If the tax year straddles January 1, 2009, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year, if $500,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

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Schedule 33

Taxable Capital Employed in Canada – Large Corporations

Corporation's name	Business number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2015-12-31

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- If the total taxable capital employed in Canada of the corporation and its related corporations is greater than $10,000,000, file a completed Schedule 33 with your T2 Corporation Income Tax Return no later than six months from the end of the tax year.
- Unless otherwise noted, all legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms **financial institution**, **long-term debt**, and **reserves**.
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, **Taxable capital employed in Canada**.

Part 1 – Capital

Add the following year-end amounts:

Reserves that have not been deducted in calculating income for the year under Part I	**101**			
Capital stock (or members' contributions if incorporated without share capital)	**103**	20,062,107		
Retained earnings	**104**	8,150,941		
Contributed surplus	**105**			
Any other surpluses	**106**			
Deferred unrealized foreign exchange gains	**107**			
All loans and advances to the corporation	**108**			
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	**109**	66,165,560		
Any dividends declared but not paid by the corporation before the end of the year	**110**			
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	**111**			
The total of all amounts, each of which is the amount, if any, in respect of a partnership in which the corporation held a membership interest at the end of the year, either directly or indirectly through another partnership (see note below)	**112**			
Subtotal (**add** lines 101 to 112)		94,378,608 ▶	94,378,608	A

Note:

Line 112 is determined by the formula (A – B) x C/D (as per paragraph 181.2(3)(g)) where:

A is the total of all amounts that would be determined for lines 101, 107, 108, 109, and 111 in respect of the partnership for its last fiscal period that ends at or before the end of the year if
  a) those lines applied to partnerships in the same manner that they apply to corporations, and
  b) those amounts were computed without reference to amounts owing by the partnership
    (i) to any corporation that held a membership interest in the partnership either directly or indirectly through another partnership, or
    (ii) to any partnership in which a corporation described in subparagraph (i) held a membership interest either directly or indirectly through another partnership.

B is the partnership's deferred unrealized foreign exchange losses at the end of the period,

C is the share of the partnership's income or loss for the period to which the corporation is entitled either directly or indirectly through another partnership, and

D is the partnership's income or loss for the period.

Part 1 – Capital (continued)

Subtotal A (from page 1)			94,378,608	A
Deduct the following amounts:				
Deferred tax debit balance at the end of the year	121	1,084,000		
Any deficit deducted in calculating its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122			
To the extent that the amount may reasonably be regarded as being included in any of lines 101 to 112 above for the year, any amount deducted under subsection 135(1) in calculating income under Part I for the year.	123			
Deferred unrealized foreign exchange losses at the end of the year	124			
Subtotal (**add** lines 121 to 124)		1,084,000 ▶	1,084,000	B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")	190		93,294,608	

Part 2 – Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	436,883
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend payable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim or similar obligation of, a partnership each member of which was, throughout the year, another corporation (other than a financial institution) that was not exempt from tax under this Part (otherwise than because of paragraph 181.1(3)(*d*)), or another partnership described in paragraph 181.2(4)(*d.1*)	406	
An interest in a partnership (see note 2 below)	407	
Investment allowance for the year (add lines 401 to 407)	490	436,883

Notes:

1. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 (other than a non-resident corporation that at no time in the year carried on business in Canada through a permanent establishment).
2. Where the corporation has an interest in a partnership held either directly or indirectly through another partnership, refer to subsection 181.2(5) for additional rules regarding the carrying value of an interest in a partnership.
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation. Refer to subsection 181.2(6) for special rules that may apply.

Part 3 – Taxable capital

Capital for the year (line 190)		93,294,608	C
Deduct: Investment allowance for the year (line 490)		436,883	D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	92,857,725	

Part 4 – Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500) 92,857,725 x Taxable income earned in Canada **610** 1,000 / Taxable income 1,000 = **Taxable capital employed in Canada** **690** 92,857,725

Notes:
1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . . . **701** ____________

Deduct the following amounts:

Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(*c*) to (*f*)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada . . . . **711** ____________

Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . . . **712** ____________

Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below) . . . . **713** ____________

Total deductions (**add** lines 711, 712, and 713) ____________ ► ____________ E

Taxable capital employed in Canada (line 701 **minus** amount E) (if negative, enter "0") . . . . **790** ____________

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 – Calculation for purposes of the small business deduction

This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (amount from line 690) . . . . ____________ F

Deduct: . . . . 10,000,000 G

Excess (amount F **minus** amount G) (if negative, enter "0") ____________ H

Calculation for purposes of the small business deduction (amount H x 0.225%) . . . . ____________ I

Enter this amount at line 415 of the T2 return.

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2015-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

		Provide only one number per shareholder				
	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) **100**	Business Number (If a corporation is not registered, enter "NR") **200**	Social insurance number **300**	Trust number **350**	Percentage common shares **400**	Percentage preferred shares **500**
1	PUC Inc	89839 7518 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

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Schedule 510

Ontario Corporate Minimum Tax

Corporation's name	Business number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2015-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	111,275,912
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	94,073,207
Total assets (total of lines 112 to 116)		205,349,119
Total revenue of the corporation for the tax year **	142	99,666,851
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	18,910,417
Total revenue (total of lines 142 to 146)		118,577,268

The corporation is subject to CMT if:
- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Adjusted net income/loss for CMT purposes

Net income/loss per financial statements *			210	888,001	
Add (to the extent reflected in income/loss):					
Provision for current income taxes/cost of current income taxes	220	1,285,959			
Provision for deferred income taxes (debits)/cost of future income taxes	222	296,000			
Equity losses from corporations	224				
Financial statement loss from partnerships and joint ventures	226				
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230				
Other additions (see note below):					
Share of adjusted net income of partnerships and joint ventures **	228				
Total patronage dividends received, not already included in net income/loss	232				
281	282				
283	284				
Subtotal		1,581,959 ▶		1,581,959	A
Deduct (to the extent reflected in income/loss):					
Provision for recovery of current income taxes/benefit of current income taxes	320				
Provision for deferred income taxes (credits)/benefit of future income taxes	322				
Equity income from corporations	324				
Financial statement income from partnerships and joint ventures	326				
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330				
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332				
Gain on donation of listed security or ecological gift	340				
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342				
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344				
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346				
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348				
Other deductions (see note below):					
Share of adjusted net loss of partnerships and joint ventures **	328				
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334				
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336				
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338				
381	382				
383	384				
385	386				
387	388				
389	390				
Subtotal		▶			B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)			490	2,469,960	

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

- exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
- include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

- Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

- Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.
- Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.
- Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive)		**515**	2,469,960	
Deduct:				
CMT loss available (amount R from Part 7)				
Minus: Adjustment for an acquisition of control *	**518**			
Adjusted CMT loss available		▶		C
Net income subject to CMT calculation (if negative, enter "0")		**520**	2,469,960	

Amount from line 520	2,469,960	x	Number of days in the tax year before July 1, 2010 / Number of days in the tax year	/ 365	x	4 % =		1
Amount from line 520	2,469,960	x	Number of days in the tax year after June 30, 2010 / Number of days in the tax year	365 / 365	x	2.7 % =	66,689	2
			Subtotal (amount 1 **plus** amount 2)				66,689	3

Gross CMT: amount on line 3 above x OAF **	**540**	66,689	
Deduct:			
Foreign tax credit for CMT purposes ***	**550**		
CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0")		66,689	D
Deduct:			
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)			
Net CMT payable (if negative, enter "0")		66,689	E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** =

Ontario allocation factor . . . . 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

*****Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000".

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year *		69,160	G			
Deduct:						
CMT credit expired *	600					
CMT credit carryforward at the beginning of the current tax year * (see note below)		69,160	▶	620	69,160	
Add:						
CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below)				650		
CMT credit available for the tax year (amount on line 620 **plus** amount on line 650)					69,160	H
Deduct:						
CMT credit deducted in the current tax year (amount P from Part 5)						I
Subtotal (amount H **minus** amount I)					69,160	J
Add:						
Net CMT payable (amount E from Part 3)		66,689				
SAT payable (amount O from Part 6 of Schedule 512)						
Subtotal		66,689	▶		66,689	K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)				670	135,849	L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)						69,160	M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)				1			
For a corporation that is not a life insurance corporation:							
CMT after foreign tax credit deduction (amount D from Part 3)	66,689	2					
For a life insurance corporation:							
Gross CMT (line 540 from Part 3)		3					
Gross SAT (line 460 from Part 6 of Schedule 512)		4					
The **greater** of amounts 3 and 4		5					
Deduct: line 2 or line 5, whichever applies:			66,689	6			
Subtotal (if negative, enter "0")					▶		N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)							
Deduct:							
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5)							
Subtotal (if negative, enter "0")					▶		O
CMT credit deducted in the current tax year (least of amounts M, N, and O)							P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	CMT credit balance *
10th previous tax year	**680**
9th previous tax year	**681**
8th previous tax year	**682**
7th previous tax year	**683**
6th previous tax year	**684**
5th previous tax year	**685**
4th previous tax year	**686**
3rd previous tax year	**687**
2nd previous tax year	**688**
1st previous tax year	**689**
Total **	

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . ______ Q

Deduct:

CMT loss expired * . . . . **700** ______

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . ______ ► **720** ______

Add:

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) . . . . **750** ______

CMT loss available (line 720 **plus** line 750) . . . . ______ R

Deduct:

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . . ______

Subtotal (if negative, enter "0") ______ S

Add:

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) . . . . **760** ______

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . **770** ______ T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:

- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	**810**	**820**
9th previous tax year	**811**	**821**
8th previous tax year	**812**	**822**
7th previous tax year	**813**	**823**
6th previous tax year	**814**	**824**
5th previous tax year	**815**	**825**
4th previous tax year	**816**	**826**
3rd previous tax year	**817**	**827**
2nd previous tax year	**818**	**828**
1st previous tax year		**829**
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

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SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2015-12-31

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
1	PUC Inc	89839 7518 RC0001	63,530,870	2,298,227
2	PUC Services Inc	87626 3526 RC0002	30,542,337	16,612,190
		Total	450 94,073,207	550 18,910,417

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter ¨NR¨ if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

*** Rules for total assets**

- Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
- Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

**** Rules for total revenue**

- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
- Include the associated corporation's share of the total revenue of partnerships and joint ventures.
- If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

T2 SCH 511

Canada

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SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2015-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
PUC Distribution Inc.

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent Ontario	**110** Date of incorporation or amalgamation, whichever is the most recent Year Month Day 2000-02-18	**120** Ontario Corporation No. 1800173

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

200 Care of (if applicable)

210 Street number 765	**220** Street name/Rural route/Lot and Concession number Queen Street	**230** Suite number

240 Additional address information if applicable (line 220 must be completed first)

250 Municipality (e.g., city, town) Sault Ste Marie	**260** Province/state ON	**270** Country CA	**280** Postal/zip code P6A 6P2

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

300 1 If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 Greco
Last name

451 Terry
First name

454 ,
Middle name(s)

460 2 Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 ☐ Please enter one of the following numbers in this box:

1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)

520 Street number

530 Street name/Rural route/Lot and Concession number

540 Suite number

550 Additional address information if applicable (line 530 must be completed first)

560 Municipality (e.g., city, town)

570 Province/state

580 Country

590 Postal/zip code

Part 6 – Language of preference

600 ☐ Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

Corporate Taxpayer Summary

Corporate information

Corporation's name . . . . PUC Distribution Inc.

Taxation Year . . . . 2015-01-01 to 2015-12-31

Jurisdiction . . . . Ontario

BC	AB	SK	MB	ON	QC	NB	NS	NO	PE	NL	XO	YT	NT	NU	OC
☐	☐	☐	☐	☒	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐

Corporation is associated . . . . Y

Corporation is related . . . . Y

Number of associated corporations . . . 2

Type of corporation . . . . Other Corporation

Total amount due (refund) federal and provincial* 17,261

* The amounts displayed on lines "Total amount due (refund) federal and provincial" are all listed in the help. Press F1 to consult the context-sensative help.

Summary of federal information

Net income . . . . -682,792

Taxable income . . . .

Donations . . . .

Calculation of income from an active business carried on in Canada . . . .

Dividends paid . . . .

Dividends paid – Regular . . . .

Dividends paid – Eligible . . . .

Balance of the low rate income pool at the end of the previous year . . . .

Balance of the low rate income pool at the end of the year . . . .

Balance of the general rate income pool at the end of the previous year . . . .

Balance of the general rate income pool at the end of the year . . . .

Part I tax (base amount) . . . .

Credits against part I tax		**Summary of tax**		**Refunds/credits**	
Small business deduction .		Part I		ITC refund	
M&P deduction		Part IV		Dividends refund	
Foreign tax credit		Part III.1		Instalments	49,428
Investment tax credits		Other*		Surtax credit	
Abatement/Other*		Provincial or territorial tax . .	66,689	Other*	

Balance due/refund (–) 17,261

* The amounts displayed on lines "Other" are all listed in the Help. Press F1 to consult the context-sensitive help.

Summary of federal carryforward/carryback information

Carryback amounts

Non-capital losses 682,792

Carryforward balances

Cumulative eligible capital 2,691,625

Summary of provincial information – provincial income tax payable

	Ontario	Québec (CO-17)	Alberta (AT1)
Net income	-682,792		
Taxable income			
% Allocation	100.00		
Attributed taxable income			
Tax payable before deduction*			
Deductions and credits			
Net tax payable			
Attributed taxable capital	N/A		N/A
Capital tax payable**	N/A		N/A
Total tax payable***	66,689		
Instalments and refundable credits			
Balance due/Refund (-)	66,689		
Logging tax payable (COZ-1179)			
Tax payable	N/A		N/A

* For Québec, this includes special taxes.

** For Québec, this includes compensation tax and registration fee.

*** For Ontario, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations. The Balance due/Refund is included in the federal Balance due/refund.

Summary of provincial carryforward amounts

Other carryforward amounts

Ontario

Corporate minimum tax credit that can be carried forward over 20 years – Schedule 510	135,849

Summary – taxable capital

Federal

Corporate name	Taxable capital used to calculate the business limit reduction (T2, line 415)	Taxable capital used to calculate the SR&ED expenditure limit for a CCPC (Schedules 31 and 49)	Taxable capital used to calculate line 233 of the T2 return	Taxable capital used to calculate line 234 of the T2 return
PUC Distribution Inc.	96,446,588	96,446,588	92,857,725	92,857,725
PUC Inc			31,808,758	31,808,758
PUC Services Inc	18,210,836	18,210,836	760,875	760,875
Total	114,657,424	114,657,424	125,427,358	125,427,358

Québec

Corporate name	Paid-up capital used to calculate the Québec business limit reduction (CO-771 and CO-771.1.3) and to calculate the additional deduction for transportation costs of remote manufacturing SMEs (CO-156.TR)	Paid-up capital used to calculate the tax credit for investment (CO-1029.8.36.IN)	Paid-up capital used to calculate the 1 million deduction (CO-1137.A and CO-1137.E)
Total			

Ontario

Corporate name	Specified capital used to calculate the expenditure limit – Ontario innovation tax credit (Schedule 566)
Total	

Other provinces

Corporate name	Capital used to calculate the Newfoundland and Labrador capital deduction on financial institutions (Schedule 306)
Total	

Five-Year Comparative Summary

Federal information (T2)

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Taxation year end	**2015-12-31**	**2014-12-31**	**2013-12-31**	**2012-12-31**	**2011-12-31**
Net income	-682,792	-1,149,357	272,580	1,598,019	1,651,227
Taxable income			272,580	1,598,019	1,651,227
Active business income			272,580	1,579,257	1,620,227
Dividends paid					
Dividends paid – Regular					
Dividends paid – Eligible					
LRIP – end of the previous year					
LRIP – end of the year					
GRIP – end of the previous year					
GRIP – end of the year					
Donations					
Balance due/refund (-)	17,261	-175,818	-299,702	-67,882	10,857
Line 996 – Amended tax return	☐	☐	☐	☐	☐

Loss carrybacks requested in prior years to reduce taxable income

Taxation year end	**2015-12-31**	**2014-12-31**	**2013-12-31**	**2012-12-31**	**2011-12-31**
Taxable income before loss carrybacks	N/A	N/A	272,580	1,598,019	1,651,227
Non-capital losses	N/A	N/A			1,149,357
Net capital losses (50%)	N/A	N/A			
Restricted farm losses	N/A	N/A			
Farm losses	N/A	N/A			
Listed personal property losses (50%)	N/A	N/A			
Total loss carried back to prior years	N/A	N/A			1,149,357
Adjusted taxable income after loss carrybacks	N/A	N/A	272,580	1,598,019	501,870

Losses in the current year carried back to previous years to reduce taxable income (according to Schedule 4)

Taxation year end	**2015-12-31**	**2014-12-31**	**2013-12-31**	**2012-12-31**	**2011-12-31**
Adjusted taxable income before current year loss carrybacks*	N/A		272,580	1,598,019	N/A
Non-capital losses	N/A			682,792	N/A
Net capital losses (50%)	N/A				N/A
Restricted farm losses	N/A				N/A
Farm losses	N/A				N/A
Listed personal property losses (50%)	N/A				N/A
Total current year losses carried back to prior years	N/A			682,792	N/A
Adjusted taxable income after loss carrybacks	N/A		272,580	915,227	N/A

* The adjusted taxable income before current year loss carryback takes into account loss carrybacks that were made in prior taxation years.

Loss carrybacks requested in prior years to reduce taxable dividends subject to Part IV tax

Taxation year end	2015-12-31	2014-12-31	2013-12-31	2012-12-31	2011-12-31
Part IV tax multiplied by 3 before loss carrybacks	N/A	N/A			
Non-capital losses	N/A	N/A			
Farm losses	N/A	N/A			
Total loss carried back to prior years	N/A	N/A			
Adjusted Part IV tax multiplied by 3 after loss carrybacks	N/A	N/A			

Losses in the current year carried back to previous years to reduce taxable dividends subject to Part IV tax (according to Schedule 4)

Taxation year end	2015-12-31	2014-12-31	2013-12-31	2012-12-31	2011-12-31
Part IV tax multiplied by 3 before current year loss carrybacks**	N/A				N/A
Non-capital losses	N/A				N/A
Farm losses	N/A				N/A
Total current year losses carried back to prior years	N/A				N/A
Adjusted Part IV tax multiplied by 3 after loss carrybacks	N/A				N/A

** The adjusted Part IV tax multiplied by 3 before current year loss carrybacks takes into account loss carrybacks that were made in prior taxation years. This amount is multiplied by 3 to help you identify the amount of the loss that is needed to reduce Part IV tax payable to zero.

Federal taxes

Taxation year end	2015-12-31	2014-12-31	2013-12-31	2012-12-31	2011-12-31
Part I			40,887	239,703	272,452
Part IV					
Part III.1					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Credits against part I tax

Taxation year end	2015-12-31	2014-12-31	2013-12-31	2012-12-31	2011-12-31
Small business deduction					
M&P deduction					
Foreign tax credit					
Political contribution					
Investment tax credit					
Abatement/other*			62,693	367,544	355,014

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Refunds/credits

Taxation year end	2015-12-31	2014-12-31	2013-12-31	2012-12-31	2011-12-31
ITC refund					
Dividend refund					
Instalments	49,428	199,278	398,555	466,437	455,580
Surtax credit					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Ontario

Taxation year end	2015-12-31	2014-12-31	2013-12-31	2012-12-31	2011-12-31
Net income	-682,792	-1,149,357	272,580	1,598,019	1,651,227
Taxable income			272,580	1,598,019	1,651,227
% Allocation	100.00	100.00	100.00	100.00	100.00
Attributed taxable income			272,580	1,598,019	1,651,227
Surtax					
Income tax payable before deduction			31,347	183,772	193,985
Income tax deductions /credits			19,081	24,920	
Net income tax payable			12,266	158,852	193,985
Taxable capital					
Capital tax payable					
Total tax payable*	66,689	23,460	57,966	158,852	193,985
Instalments and refundable credits					
Balance due/refund**	66,689	23,460	57,966	158,852	193,985

* For taxation years ending before January 1, 2009, this includes the corporate minimum tax and the premium tax. For taxation years ending after December 31, 2008, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations.

** For taxation years ending after December 31, 2008, the Balance due/Refund is included in the federal Balance due/refund.

Canada Revenue Agency
Agence du revenu du Canada

Information Return for Corporations Filing Electronically

- You have to complete this return for every initial and amended T2 Corporation Income Tax Return electronically filed to the Canada Revenue Agency (CRA) on your behalf.
- By completing Part 2 and signing Part 3, you acknowledge that, under the *Income Tax Act*, you have to keep all records used to prepare your corporation income tax return, and provide this information to us on request.
- Part 4 must be completed by either you or the electronic transmitter of your corporation income tax return.
- Give the signed original of this return to the transmitter and keep a copy in your own records for six years.
- **Do not submit** this form to the CRA unless we ask for it.
- We are responsible for ensuring the confidentiality of your electronically filed tax information only after we have accepted it.

This return is for your records. Do not send it to us unless we ask for it.

Part 1 – Identification

Corporation's name: PUC Distribution Inc.

Business number: 86709 6778 RC0001

Tax year ▶	From Y M D 2016-01-01	To Y M D 2016-12-31	Is this an amended return? . . . . ☐ Yes ☒ No

Part 2 – Declaration

Enter the following amounts, if applicable, from your corporation income tax return for the tax year noted above:

Net income (or loss) for income tax purposes from Schedule 1, financial statements, or GIFI (line 300)	-1,935,479
Part I tax payable (line 700)	
Part II surtax payable (line 708)	
Part III.1 tax payable (line 710)	
Part IV tax payable (line 712)	
Part IV.1 tax payable (line 716)	
Part VI tax payable (line 720)	
Part VI.1 tax payable (line 724)	
Part XIV tax payable (line 728)	
Net provincial and territorial tax payable (line 760)	

Part 3 – Certification and authorization

I, Greco (Last name) Terry (First name) Vice-President (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined the corporation T2 income tax return, including accompanying schedules and statements, and that the information given on the T2 return and this T183 Corp information return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

I authorize the transmitter identified in Part 4 to electronically file the corporation income tax return identified in Part 1. The transmitter can also modify the information originally filed in response to any errors Canada Revenue Agency identifies. This authorization expires when the Minister of National Revenue accepts the electronic return as filed.

Date (yyyy/mm/dd):

Signature of an authorized signing officer of the corporation:

Telephone number: (705) 759-6566

Part 4 – Transmitter identification

The following transmitter has electronically filed the tax return of the corporation identified in Part 1.

Name of person or firm: KPMG LLP

Electronic filer number: D4481

Privacy statement

Personal information is collected under the *Income Tax Act* to administer tax, benefits, and related programs. It may also be used for any purpose related to the administration or enforcement of the Act such as audit, compliance and the payment of debts owed to the Crown. It may be shared or verified with other federal, provincial/territorial government institutions to the extent authorized by law. Failure to provide this information may result in interest payable, penalties or other actions. Under the *Privacy Act*, individuals have the right to access their personal information and request correction if there are errors or omissions. Refer to Info Source **http://www.cra-arc.gc.ca/gncy/tp/nfsrc/nfsrc-eng.html**, personal information bank CRA PPU 047.

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

200

055 **Do not use this area**

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act* and *Income Tax Regulations*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see cra.gc.ca or Guide T4012, *T2 Corporation - Income Tax Guide*.

Identification

Business number (BN) **001** 86709 6778 RC0001

Corporation's name
002 PUC Distribution Inc.

Address of head office
Has this address changed since the last time we were notified? . . . . **010** 1 Yes ☐ 2 No ☒
(If **yes**, complete lines 011 to 018.)
011 500 Second Line East
012
City **015** Sault Ste Marie
Province, territory, or state **016** ON
Country (other than Canada) **017**
Postal code/Zip code **018** P6B 4K1

Mailing address (if different from head office address)
Has this address changed since the last time we were notified? . . . . **020** 1 Yes ☐ 2 No ☒
(If **yes**, complete lines 021 to 028.)
021 c/o
022
023
City **025**
Province, territory, or state **026**
Country (other than Canada) **027**
Postal code/Zip code **028**

Location of books and records (if different from head office address)
Has this address changed since the last time we were notified? . . . . **030** 1 Yes ☐ 2 No ☒
(If **yes**, complete lines 031 to 038.)
031 500 Second Line East
032
City **035** Sault Ste Marie
Province, territory, or state **036** ON
Country (other than Canada) **037**
Postal code/Zip code **038** P6B 4K1

040 **Type of corporation at the end of the tax year**
1 ☐ Canadian-controlled private corporation (CCPC)
2 ☐ Other private corporation
3 ☐ Public corporation
4 ☐ Corporation controlled by a public corporation
5 ☒ Other corporation (specify, below) Electrity Act

If the type of corporation changed during the tax year, provide the effective date of the change . . . . **043** Year Month Day

To which tax year does this return apply?
Tax year start **060** Year Month Day 2016-01-01
Tax year-end **061** Year Month Day 2016-12-31

Has there been an acquisition of control resulting in the application of subsection 249(4) since the tax year start on line 060? . . . . **063** 1 Yes ☐ 2 No ☒
If **yes**, provide the date control was acquired . . . . **065** Year Month Day

Is the date on line 061 a deemed tax year-end according to subsection 249(3.1)? . . . . **066** 1 Yes ☐ 2 No ☒

Is the corporation a professional corporation that is a member of a partnership? . . . . **067** 1 Yes ☐ 2 No ☒

Is this the first year of filing after:
Incorporation? . . . . **070** 1 Yes ☐ 2 No ☒
Amalgamation? . . . . **071** 1 Yes ☐ 2 No ☒
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . **072** 1 Yes ☐ 2 No ☒
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . **076** 1 Yes ☐ 2 No ☒

Is this the final return up to dissolution? . . . . **078** 1 Yes ☐ 2 No ☒

If an election was made under section 261, state the functional currency used **079**

Is the corporation a resident of Canada? **080** 1 Yes ☒ 2 No ☐
If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . **082** 1 Yes ☐ 2 No ☒
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
1 ☐ Exempt under paragraph 149(1)(e) or (l)
2 ☐ Exempt under paragraph 149(1)(j)
3 ☐ Exempt under paragraph 149(1)(t)
4 ☐ Exempt under other paragraphs of section 149

Do not use this area

095 **096** **898**

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	**150**	☒	9
Is the corporation an associated CCPC?	**160**	☒	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	**161**	☐	49
Does the corporation have any non-resident shareholders who own voting shares?	**151**	☐	19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	**162**	☐	11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	**163**	☐	44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	**164**	☐	14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	**165**	☐	15
Is the corporation claiming a loss or deduction from a tax shelter?	**166**	☐	T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	**167**	☐	T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	**168**	☐	22
Did the corporation own any shares in one or more foreign affiliates in the tax year?	**169**	☐	25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the *Income Tax Regulations*?	**170**	☐	29
Did the corporation have a total amount over $1 million of reportable transactions with non-arm's length non-residents?	**171**	☐	T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	**173**	☒	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	**172**	☐	
Does the corporation earn income from one or more Internet webpages or websites?	**180**	☐	88
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	**201**	☒	1
Has the corporation made any charitable donations; gifts of cultural or ecological property; or gifts of medicine?	**202**	☐	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	**203**	☐	3
Is the corporation claiming any type of losses?	**204**	☒	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	**205**	☐	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	**206**	☐	6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	**207**	☐	7
Does the corporation have any property that is eligible for capital cost allowance?	**208**	☒	8
Does the corporation have any property that is eligible capital property?	**210**	☒	10
Does the corporation have any resource-related deductions?	**212**	☐	12
Is the corporation claiming deductible reserves (other than transitional reserves under section 34.2)?	**213**	☐	13
Is the corporation claiming a patronage dividend deduction?	**216**	☐	16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	**217**	☐	17
Is the corporation an investment corporation or a mutual fund corporation?	**218**	☐	18
Is the corporation carrying on business in Canada as a non-resident corporation?	**220**	☐	20
Is the corporation claiming any federal, provincial, or territorial foreign tax credits, or any federal logging tax credits?	**221**	☐	21
Does the corporation have any Canadian manufacturing and processing profits?	**227**	☐	27
Is the corporation claiming an investment tax credit?	**231**	☐	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	**232**	☐	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	**233**	☒	33/34/35
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	**234**	☒	
Is the corporation claiming a surtax credit?	**237**	☐	37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	**238**	☐	38
Is the corporation claiming a Part I tax credit?	**242**	☐	42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	**243**	☐	43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	**244**	☐	45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	**249**	☐	46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	**250**	☐	39
Is the corporation claiming a Canadian film or video production tax credit refund?	**253**	☐	T1131
Is the corporation claiming a film or video production services tax credit refund?	**254**	☐	T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	**255**	☐	92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates in the tax year?	271	☐	T1134
Did the corporation own or hold specified foreign property where the total cost amount of all such property, at any time in the year, was more than CAN$100,000?	259	☐	T1135
Did the corporation transfer or loan property to a non-resident trust?	260	☐	T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261	☐	T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262	☐	T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263	☐	T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264	☐	T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	☐	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266	☐	T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267	☐	T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	☐	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269	☐	54

Additional information

Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270	1 Yes ☒	2 No ☐
Is the corporation inactive?	280	1 Yes ☐	2 No ☒

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution

Specify the principal products mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electrical power distribution	285	100.000 %
286		287	%
288		289	%

Did the corporation immigrate to Canada during the tax year?	291	1 Yes ☐	2 No ☒
Did the corporation emigrate from Canada during the tax year?	292	1 Yes ☐	2 No ☒
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293	1 Yes ☐	2 No ☐

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 Year Month Day

If the corporation's major business activity is construction, did you have any subcontractors during the tax year?	295	1 Yes ☐	2 No ☐

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.		300	-1,935,479	A
Deduct: Charitable donations from Schedule 2	311			
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction*	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Subtotal		►		B
Subtotal (amount A **minus** amount B) (if negative, enter "0")				C
Section 110.5 additions or subparagraph 115(1)(a)(vii) additions		355		D
Taxable income (amount C **plus** amount D)		360		
Income exempt under paragraph 149(1)(t)		370		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)				Z
Taxable income for the year from a personal services business**				Z.1

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 9.

** For a taxation year that ends after 2015.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 . . . . **400** ________ A

Taxable income from line 360 on page 3, **minus** 100/28 3.57143 of the amount on line 632* on page 8, **minus** 4 times the amount on line 636** on page 8, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . . **405** ________ B

Business limit (see notes 1 and 2 below) . . . . **410** ________ C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C ________ x **415** *** 226,565 D / 11,250 = ... ________ E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . **425** ________ F

Business limit the CCPC assigns under subsection 125(3.2) (amount O below) . . . . ________ G

Amount F **minus** amount G . . . . ________ H

Small business deduction

Amount A, B, C, or H, whichever is the least ________ x Number of days in the tax year before January 1, 2016 / Number of days in the tax year 366 x 17 % = ________ 1

Amount A, B, C, or H, whichever is the least ________ x Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366 x 17.5 % = ________ 2

Total of amounts 1 and 2 (enter amount I on line J on page 8) **430** ________ I

***** Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

****** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

***** Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

Specified corporate income and assignment under subsection 125(3.2)

	J Name of corporation receiving the income and assigned amount	K Business number of the corporation	L Income for the small business deduction given to the corporation identified in column J [under clause 125(1)(a)(i)(B)] [3]	M Business limit assigned to corporation identified in column J [4]
1.				
			Total ________ N	Total ________ O

Notes:

3. This amount is [as defined in subsection 125(7) **specified corporate income** (a)(i)] the total of all amounts each of which is income from an active business of the corporation for the year from the provision of services or property to a private corporation (directly or indirectly, in any manner whatever) if

   (A) at any time in the year, the corporation (or one of its shareholders) or a person who does not deal at arm's length with the corporation (or one of its shareholders) holds a direct or indirect interest in the private corporation, and

   (B) it is not the case that all or substantially all of the corporation's income for the year from an active business is from the provision of services or property to

   (I) persons (other than the private corporation) with which the corporation deals at arm's length, or

   (II) partnerships with which the corporation deals at arm's length, other than a partnership in which a person that does not deal at arm's length with the corporation holds a direct or indirect interest.
4. The amount of the business limit you assign cannot be greater than the amount in column L.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from page 3 (line 360 or amount Z, whichever applies) . . . . ________ A

Lesser of amounts B9 and H9 from Part 9 of Schedule 27 . . . . ________ B

Amount K13 from Part 13 of Schedule 27 . . . . ________ C

Personal services business income . . . . **432** ________ D

Amount used to calculate the credit union deduction (amount F from Schedule 17) . . . . ________ E

Amount from line 400, 405, 410, or amount H on page 4, whichever is the least . . . . ________ F

Aggregate investment income from line 440 on page 6* . . . . ________ G

Subtotal (**add** amounts B to G) ________ ▶ ________ H

Amount A **minus** amount H (if negative, enter "0") . . . . ________ I

General tax reduction for Canadian-controlled private corporations – Amount I **multiplied** by 13 % . . . . ________ J
Enter amount J on line 638 on page 8.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies) . . . . ________ K

Lesser of amounts B9 and H9 from Part 9 of Schedule 27 . . . . ________ L

Amount K13 from Part 13 of Schedule 27 . . . . ________ M

Personal services business income . . . . **434** ________ N

Amount used to calculate the credit union deduction (amount F from Schedule 17) . . . . ________ O

Subtotal (**add** amounts L to O) ________ ▶ ________ P

Amount K **minus** amount P (if negative, enter "0") . . . . ________ Q

General tax reduction – Amount Q **multiplied** by 13 % . . . . ________ R
Enter amount R on line 639 on page 8.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 . . . . **440** ________ A

Amount A ________ x Number of days in the tax year before January 1, 2016 / Number of days in the tax year 366 x 26 2 / 3 % = ________ 1

Amount A ________ x Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366 x 30 2 / 3 % = ________ 2

Subtotal (amount 1 **plus** amount 2) ________ ▶ ________ B

Foreign investment income from Schedule 7 . . . . **445** ________ C

Amount C ________ x Number of days in the tax year before January 1, 2016 / Number of days in the tax year 366 x 9 1 / 3 % = ________ 3

Amount C ________ x Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366 x 8 % = ________ 4

Subtotal (amount 3 **plus** amount 4) ________ D

Foreign non-business income tax credit from line 632 on page 8 **minus** amount D (if negative, enter "0") . . . . ________ E

Amount B **minus** amount E (if negative, enter "0") . . . . ________ F

Foreign non-business income tax credit from line 632 on page 8 . . . . ________ G

Number of days in the tax year before January 1, 2016 / Number of days in the tax year 366 x 35 = ... ________ 5

Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366 x 38 2 / 3 = ... 38.66667 6

Subtotal (amount 5 **plus** amount 6) 38.6667 H

Amount G ________ x 100 / H x 100 / 38.6667 = ... ________ I

Taxable income from line 360 on page 3 . . . . ________ J

Deduct:

Amount from line 400, 405, 410, or amount H on page 4, whichever is the least . . . . ________ K

Amount I . . . . ________ L

Foreign business income tax credit from line 636 on page 8 . . . . ________ x 4 = ________ M

Subtotal (total of amounts K to M) ________ ▶ ________ N

Subtotal (amount J **minus** amount N) ________ O

Amount O ________ x Number of days in the tax year before January 1, 2016 / Number of days in the tax year 366 x 26 2 / 3 % = ________ 7

Amount O ________ x Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366 x 30 2 / 3 % = ________ 8

Subtotal (amount 7 **plus** amount 8) ________ ▶ ________ P

Part I tax payable **minus** investment tax credit refund (line 700 **minus** line 780 from page 9) . . . . ________ Q

Refundable portion of Part I tax – Amount F, P, or Q, whichever is the least . . . . **450** ________ R

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year **460**

Deduct:

Dividend refund for the previous tax year **465**

▶ A

Add the total of:

Refundable portion of Part I tax from line 450 on page 6 . . . . B

Total Part IV tax payable from Schedule 3 C

Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation **480**

▶ D

Refundable dividend tax on hand at the end of the tax year – Amount A **plus** amount D **485**

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 3 of Schedule 3 . . . . E

Amount E ______ x Number of days in the tax year before January 1, 2016 ______ / Number of days in the tax year 366 x 33 1 / 3 % = ______ 1

Amount E ______ x Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366 x 38 1 / 3 % = ______ 2

Subtotal (amount 1 **plus** amount 2) ▶ F

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . G

Dividend refund – Amount F or G, whichever is less . . . . H

Enter amount H on line 784 on page 9.

Part I tax

Base amount Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 %*	**550**		A

Personal services business income tax (section 123.5)

Taxable income from a personal services business **555** ______ x Number of days in the tax year after December 31, 2015 366 / Number of days in the taxation year 366 x 5 % = **560** ______ B

Recapture of investment tax credit from Schedule 31	**602**		C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6			D	
Taxable income from line 360 on page 3		E		
Deduct:				
Amount from line 400, 405, 410, or amount H on page 4, whichever is the least		F		
Net amount (amount E **minus** amount F)		►		G

Amount D or G, whichever is less ______ x Number of days in the tax year before January 1, 2016 ______ / Number of days in the tax year 366 x 6 2 / 3 % = ______ 1

Amount D or G, whichever is less ______ x Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366 x 10 2 / 3 % = ______ 2

Refundable tax on CCPC's investment income (amount 1 **plus** amount 2)	**604**	►		H
Subtotal (**add** amounts A, B, C, and H)				I

Deduct:

Small business deduction from line 430 on page 4			J
Federal tax abatement	**608**		
Manufacturing and processing profits deduction from Schedule 27	**616**		
Investment corporation deduction	**620**		
Taxed capital gains **624**			
Additional deduction – credit unions from Schedule 17	**628**		
Federal foreign non-business income tax credit from Schedule 21	**632**		
Federal foreign business income tax credit from Schedule 21	**636**		
General tax reduction for CCPCs from amount J on page 5	**638**		
General tax reduction from amount R on page 5	**639**		
Federal logging tax credit from Schedule 21	**640**		
Eligible Canadian bank deduction under section 125.21	**641**		
Federal qualifying environmental trust tax credit	**648**		
Investment tax credit from Schedule 31	**652**		
Subtotal		►	K

Part I tax payable – Amount I **minus** amount K		L

Enter amount L on line 700 on page 9.

Privacy statement

Personal information is collected under the *Income Tax Act* to administer tax, benefits, and related programs. It may also be used for any purpose related to the administration or enforcement of the Act such as audit, compliance and the payment of debts owed to the Crown. It may be shared or verified with other federal, provincial/territorial government institutions to the extent authorized by law. Failure to provide this information may result in interest payable, penalties or other actions. Under the *Privacy Act*, individuals have the right to access their personal information and request correction if there are errors or omissions. Refer to Info Source cra.gc.ca/gncy/tp/nfsrc/nfsrc-eng.html, personal information bank CRA PPU 047.

Summary of tax and credits

Federal tax

Part I tax payable from amount L on page 8	**700**	
Part II surtax payable from Schedule 46	**708**	
Part III.1 tax payable from Schedule 55	**710**	
Part IV tax payable from Schedule 3	**712**	
Part IV.1 tax payable from Schedule 43	**716**	
Part VI tax payable from Schedule 38	**720**	
Part VI.1 tax payable from Schedule 43	**724**	
Part XIII.1 tax payable from Schedule 92	**727**	
Part XIV tax payable from Schedule 20	**728**	
Total federal tax		

Add provincial or territorial tax:

Provincial or territorial jurisdiction **750** ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	**760**	
Total tax payable	**770**	A

Deduct other credits:

Investment tax credit refund from Schedule 31	**780**		
Dividend refund from amount H on page 7	**784**		
Federal capital gains refund from Schedule 18	**788**		
Federal qualifying environmental trust tax credit refund	**792**		
Canadian film or video production tax credit refund (Form T1131)	**796**		
Film or video production services tax credit refund (Form T1177)	**797**		
Tax withheld at source	**800**		
Total payments on which tax has been withheld	**801**		
Provincial and territorial capital gains refund from Schedule 18	**808**		
Provincial and territorial refundable tax credits from Schedule 5	**812**		
Tax instalments paid	**840**	66,690	
Total credits	**890**	66,690 ▶	66,690 B
Balance (amount A **minus** amount B)			-66,690

Refund code **894** 1 Overpayment 66,690

If the result is positive, you have a **balance unpaid**.
If the result is negative, you have an **overpayment**.
Enter the amount on whichever line applies.
Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid

For information on how to make your payment, go to cra.gc.ca/payments.

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information

910 Branch number

914 Institution number **918** Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? **896** 1 Yes ☐ 2 No ☒

If this return was prepared by a tax preparer for a fee, provide their EFILE number **920** D4481

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Certification

I, **950** Greco (Last name) **951** Terry (First name) **954** Vice-President (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 Date (yyyy/mm/dd) Signature of the authorized signing officer of the corporation **956** (705) 759-6566 Telephone number

Is the contact person the same as the authorized signing officer? If no, complete the information below **957** 1 Yes ☒ 2 No ☐

958 Name of other authorized person **959** Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. **990** 1

Schedule of Instalment Remittances

Name of corporation contact

Telephone number

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
	Instalments	66,690

Total amount of instalments claimed (carry the result to line 840 of the T2 Return) 66,690 **A**

Total instalments credited to the taxation year per T9 66,690 **B**

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

Canada Revenue Agency   Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2016-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	22,895,859	22,442,698
	Total tangible capital assets	2008	+	101,485,749	95,032,119
	Total accumulated amortization of tangible capital assets	2009	–	12,072,523	7,722,548
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	2,169,439	1,523,643
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	114,478,524	111,275,912
	Liabilities				
	Total current liabilities	3139	+	16,173,162	24,894,625
	Total long-term liabilities	3450	+	70,412,751	58,168,239
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	86,585,913	83,062,864
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	27,892,611	28,213,048
	Total liabilities and shareholder equity	3640	=	114,478,524	111,275,912
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	7,830,504	8,150,941

***** Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Canada Revenue Agency Agence du revenu du Canada

SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2016-12-31

Income statement information

Description **GIFI**

Operating name	**0001**	
Description of the operation	**0002**	
Sequence number	**0003**	01

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+	98,260,140	95,999,589
	Cost of sales	8518	–	81,410,411	73,275,057
	Gross profit/loss	8519	=	16,849,729	22,724,532
	Cost of sales	8518	+	81,410,411	73,275,057
	Total operating expenses	9367	+	19,387,446	19,280,154
	Total expenses (mandatory field)	9368	=	100,797,857	92,555,211
	Total revenue (mandatory field)	8299	+	101,787,208	99,666,851
	Total expenses (mandatory field)	9368	–	100,797,857	92,555,211
	Net non-farming income	9369	=	989,351	7,111,640
	Farming income statement information				
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	989,351	7,111,640
	Total other comprehensive income	9998	=	-1,350,788	-4,641,680
	Extraordinary items and income (linked to Schedule 140)				
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–	-44,000	1,285,959
	Future (deferred) income tax provision	9995	–	3,000	296,000
	Total – Other comprehensive income	9998	+	-1,350,788	-4,641,680
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	-320,437	888,001

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Schedule 141

Notes Checklist

Corporation's name	Business number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2016-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the **accountant**) who prepared or reported on the financial statements. If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and T4012*, T2 Corporation – Income Tax Guide.*
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? . . . . . **095** 1 Yes ☒ 2 No ☐

Is the accountant connected* with the corporation? . . . . . **097** 1 Yes ☐ 2 No ☒

Note
If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you **do have** to complete Part 4, as applicable.

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: **198**

Completed an auditor's report . . . . . 1 ☒

Completed a review engagement report . . . . . 2 ☐

Conducted a compilation engagement . . . . . 3 ☐

Part 3 – Reservations

If you selected option 1 or 2 under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . . . **099** 1 Yes ☐ 2 No ☒

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: **110**

Prepared the tax return (financial statements prepared by client) . . . . . 1 ☐

Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . . . 2 ☐

Were notes to the financial statements prepared? . . . . . **101** 1 Yes ☒ 2 No ☐

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes? . . . . . **104** 1 Yes ☐ 2 No ☒

Is re-evaluation of asset information mentioned in the notes? . . . . . **105** 1 Yes ☐ 2 No ☒

Is contingent liability information mentioned in the notes? . . . . . **106** 1 Yes ☒ 2 No ☐

Is information regarding commitments mentioned in the notes? . . . . . **107** 1 Yes ☐ 2 No ☒

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . **108** 1 Yes ☐ 2 No ☒

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . **200** 1 Yes ☐ 2 No ☒

If **yes**, enter the amount recognized:

		In net income Increase (decrease)		**In OCI** Increase (decrease)
Property, plant, and equipment	**210**		**211**	
Intangible assets	**215**		**216**	
Investment property	**220**			
Biological assets	**225**			
Financial instruments	**230**		**231**	
Other	**235**		**236**	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? . . . . . **250** 1 Yes ☐ 2 No ☒

Did the corporation apply hedge accounting during the tax year? . . . . . **255** 1 Yes ☐ 2 No ☒

Did the corporation discontinue hedge accounting during the tax year? . . . . . **260** 1 Yes ☐ 2 No ☒

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . **265** 1 Yes ☐ 2 No ☒

If **yes**, you have to maintain a separate reconciliation.

SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2016-12-31

Assets – lines 1000 to 2599

1000	3,899,721	**1060**	6,620,270	**1062**	10,175,782
1120	1,486,453	**1400**	100,201	**1483**	550,032
1484	63,400	**1599**	22,895,859	**1600**	865,150
1680	25,127,001	**1681**	-1,989,504	**1740**	17,691,102
1741	-2,365,780	**1785**	57,802,496	**1786**	-7,717,239
2008	101,485,749	**2009**	-12,072,523	**2420**	1,088,439
2421	1,081,000	**2589**	2,169,439	**2599**	114,478,524

Liabilities – lines 2600 to 3499

2620	13,766,613	**2770**	207,980	**2920**	1,211,084
2961	987,485	**3139**	16,173,162	**3145**	37,413,151
3220	1,847,591	**3260**	26,534,040	**3320**	4,617,969
3450	70,412,751	**3499**	86,585,913		

Shareholder equity – lines 3500 to 3640

3500	20,062,107	**3600**	7,830,504	**3620**	27,892,611
3640	114,478,524				

Retained earnings – lines 3660 to 3849

3660	8,150,941	**3680**	1,030,351	**3740**	-1,350,788
3849	7,830,504				

SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2016-12-31

Description

Sequence number **0003** 01

Other comprehensive income – lines 7000 to 7020

7020	-1,350,788

Revenue – lines 8000 to 8299

8000	98,260,140	**8089**	98,260,140	**8090**	33,313
8230	3,493,755	**8299**	101,787,208		

Cost of sales – lines 8300 to 8519

8320	81,410,411	**8518**	81,410,411	**8519**	16,849,729

Operating expenses – lines 8520 to 9369

8670	4,202,174	**8714**	3,058,063	**8717**	1,572,173
9270	1,388,930	**9273**	5,977,871	**9284**	3,188,235
9367	19,387,446	**9368**	100,797,857	**9369**	989,351

Extraordinary items and taxes – lines 9970 to 9999

9970	989,351	**9990**	-44,000	**9995**	3,000
9998	-1,350,788	**9999**	-320,437		

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

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Net Income (Loss) for Income Tax Purposes

Schedule 1

Corporation's name	Business Number	Tax year end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2016-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125			-320,437	A

Add:

Provision for income taxes – current	101	-44,000		
Provision for income taxes – deferred	102	3,000		
Amortization of tangible assets	104	4,202,174		
Non-deductible meals and entertainment expenses	121	3,105		
Subtotal of additions		4,164,279 ▶	4,164,279	

Other additions:

Taxable/non-deductible other comprehensive income items	239	1,350,788		

Miscellaneous other additions:

1 Description 605	2 Amount 295

Total of column 2	▶ 296			
Subtotal of other additions	199	1,350,788 ▶	1,350,788	
Total additions	500	5,515,067 ▶	5,515,067	B
Amount A **plus** amount B			5,194,630	C

Deduct:

Capital cost allowance from Schedule 8	403	5,587,907		
Cumulative eligible capital deduction from Schedule 10	405	188,414		
Subtotal of deductions		5,776,321 ▶	5,776,321	

Other deductions:

Miscellaneous other deductions:

	1 Description 705	2 Amount 395
1	Regulatory charges deferred for accounting purposes	1,353,788

Total of column 2	1,353,788 ▶	396	1,353,788		
Subtotal of other deductions		499	1,353,788 ▶	1,353,788	
Total deductions		510	7,130,109 ▶	7,130,109	D
Net income (loss) for income tax purposes (amount C **minus** amount D)				-1,935,479	E

Enter amount E on line 300 of the T2 return.

T2 SCH 1 E (16)

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Schedule 4

Corporation Loss Continuity and Application

Corporation's name	Business number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2016-12-31

- Use this form to determine the continuity and use of available losses; to determine a current-year non-capital loss, farm loss, restricted farm loss, or limited partnership loss; to determine the amount of restricted farm loss and limited partnership loss that can be applied in a year; and to ask for a loss carryback to previous years.
- A corporation can choose whether or not to deduct an available loss from income in a tax year. The corporation can deduct losses in any order. However, for each type of loss, deduct the oldest loss first.
- According to subsection 111(4) of the *Income Tax Act*, when control has been acquired, no amount of capital loss incurred for a tax year ending before that time is deductible in computing taxable income in a tax year ending after that time. Also, no amount of capital loss incurred in a tax year ending after that time is deductible in computing taxable income of a tax year ending before that time.
- When control has been acquired, subsection 111(5) provides for similar treatment of non-capital and farm losses, except as listed in paragraphs 111(5)(a) and (b).
- For information on these losses, see the *T2 Corporation – Income Tax Guide*.
- File one completed copy of this schedule with the T2 return, or send the schedule by itself to the tax centre where the return is filed.
- All legislative references are to the *Income Tax Act*.

Part 1 – Non-capital losses

Determination of current-year non-capital loss

Net income (loss) for income tax purposes				-1,935,479	A
Deduct: (increase a loss)					
Net capital losses deducted in the year (enter as a positive amount)			a		
Taxable dividends deductible under section 112 or subsections 113(1) or 138(6)			b		
Amount of Part VI.1 tax deductible under paragraph 110(1)(k)			c		
Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2)			d		
Subtotal (total of amounts a to d)			▶		B
Subtotal (amount A **minus** amount B; if positive, enter "0")				-1,935,479	C
Deduct: (increase a loss)					
Section 110.5 or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions					D
Subtotal (amount C **minus** amount D)				-1,935,479	E
Add: (decrease a loss)					
Current-year farm loss (the lesser of: the net loss from farming or fishing included in income and the non-capital loss before deducting the farm loss)					F
Current-year non-capital loss (amount E **plus** amount F; if positive, enter "0")				-1,935,479	G
If amount G is negative, enter it on line 110 as a positive.					

Continuity of non-capital losses and request for a carryback

Non-capital loss at the end of the previous tax year			e		
Deduct: Non-capital loss expired (note 1)	**100**		f		
Non-capital losses at the beginning of the tax year (amount e **minus** amount f)	**102**		▶		H
Add:					
Non-capital losses transferred on an amalgamation or on the wind-up of a subsidiary (note 2) corporation	**105**		g		
Current-year non-capital loss (from amount G)	**110**	1,935,479	h		
Subtotal (amount g **plus** amount h)		1,935,479	▶	1,935,479	I
Subtotal (amount H **plus** amount I)				1,935,479	J

Note 1: A non-capital loss expires as follows:

- after **10** tax years if it arose in a tax year ending after March 22, 2004, and before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

An allowable business investment loss becomes a net capital loss after **10** tax years if it arose in a tax year ending after March 22, 2004.

Note 2: Subsidiary is defined in subsection 88(1) as a taxable Canadian corporation of which 90% or more of each class of issued shares are owned by its parent corporation and the remaining shares are owned by persons that deal at arm's length with the parent corporation.

Part 1 – Non-capital losses (continued)

Deduct:

Other adjustments (includes adjustments for an acquisition of control)	150		i		
Section 80 – Adjustments for forgiven amounts	140		j		
Subsection 111(10) – Adjustments for fuel tax rebate			j.1		
Non-capital losses of previous tax years applied in the current tax year Enter amount k on line 331 of the T2 Return.	130		k		
Current and previous year non-capital losses applied against current-year taxable dividends subject to Part IV tax (note 3)	135		l		
Subtotal (total of amounts i to l)			▶		K
Non-capital losses before any request for a carryback (amount J **minus** amount K)				1,935,479	L

Deduct – **Request to carry back non-capital loss to:**

First previous tax year to reduce taxable income	901		m		
Second previous tax year to reduce taxable income	902		n		
Third previous tax year to reduce taxable income	903	272,580	o		
First previous tax year to reduce taxable dividends subject to Part IV tax	911		p		
Second previous tax year to reduce taxable dividends subject to Part IV tax	912		q		
Third previous tax year to reduce taxable dividends subject to Part IV tax	913		r		
Total of requests to carry back non-capital losses to previous tax years (total of amounts m to r)		272,580	▶	272,580	M
Closing balance of non-capital losses to be carried forward to future tax years (amount L **minus** amount M)	180			1,662,899	N

Note 3: Amount l is the total of lines 330 and 335 from Schedule 3, *Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation*.

Part 2 – Capital losses

Continuity of capital losses and request for a carryback

Capital losses at the end of the previous tax year	200		a		
Capital losses transferred on an amalgamation or on the wind-up of a subsidiary corporation	205		b		
Subtotal (amount a **plus** amount b)			▶		A
Deduct:					
Other adjustments (includes adjustments for an acquisition of control)	250		c		
Section 80 – Adjustments for forgiven amounts	240		d		
Subtotal (amount c **plus** amount d)			▶		B
Subtotal (amount A **minus** amount B)					C
Add: Current-year capital loss (from the calculation on Schedule 6, *Summary of Dispositions of Capital Property*)	210				D
Unused non-capital losses that expired in the tax year (note 4)			e		
Allowable business investment losses (ABILs) that expired as non-capital losses at the end of the previous tax year (note 5)			f		
Enter amount e or f, whichever is less	215		g		
ABILs expired as non-capital losses: line 215 **multiplied** by 2.000000	220				E
Subtotal (total of amounts C to E)					F

Note
If there has been an amalgamation or a wind–up of a subsidiary, do a separate calculation of the ABIL expired as non-capital loss for each predecessor or subsidiary corporation. Add all these amounts and enter the total on line 220 above.

Note 4: If the loss was incurred in a tax year ending after March 22, 2004, determine the amount of the loss from the 11th previous tax year and enter the part of that loss that was not used in previous years and the current year on line e.

Note 5: If the ABILs were incurred in a tax year ending after March 22, 2004, enter the amount of the ABILs from the 11th previous tax year. Enter the full amount on line f.

Part 2 – Capital losses (continued)

Deduct: Capital losses from previous tax years applied against the current-year net capital gain (note 6)	225		G
Capital losses before any request for a carryback (amount F **minus** amount G)			H

Deduct – **Request to carry back capital loss to** (note 7):

	Capital gain (100%)		Amount carried back (100%)	
First previous tax year		951		h
Second previous tax year		952		i
Third previous tax year		953		j
Subtotal (total of amounts h to j)			▶	I

Closing balance of capital losses to be carried forward to future tax years (amount H **minus** amount I)	280		J

Note 6: To get the net capital losses required to reduce the taxable capital gain included in the net income (loss) for the current-year tax, enter the amount from line 225 **divided** by 2 at line 332 of the T2 return.

Note 7: On line 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, divide this amount by 2. The result represents the 50% inclusion rate.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

Farm losses at the end of the previous tax year			a		
Deduct: Farm loss expired (note 8)	300		b		
Farm losses at the beginning of the tax year (amount a **minus** amount b)	302		▶		A
Add:					
Farm losses transferred on an amalgamation or on the wind–up of a subsidiary corporation	305		c		
Current-year farm loss (amount F in Part 1)	310		d		
Subtotal (amount c **plus** amount d)			▶		B
Subtotal (amount A **plus** amount B)					C
Deduct:					
Other adjustments (includes adjustments for an acquisition of control)	350		e		
Section 80 – Adjustments for forgiven amounts	340		f		
Farm losses of previous tax years applied in the current tax year Enter amount g on line 334 of the T2 Return.	330		g		
Current and previous year farm losses applied against current-year taxable dividends subject to Part IV tax (note 9)	335		h		
Subtotal (total of amounts e to h)			▶		D
Farm losses before any request for a carryback (amount C **minus** amount D)					E
Deduct – **Request to carry back farm loss to:**					
First previous tax year to reduce taxable income	921		i		
Second previous tax year to reduce taxable income	922		j		
Third previous tax year to reduce taxable income	923		k		
First previous tax year to reduce taxable dividends subject to Part IV tax	931		l		
Second previous tax year to reduce taxable dividends subject to Part IV tax	932		m		
Third previous tax year to reduce taxable dividends subject to Part IV tax	933		n		
Subtotal (total of amounts i to n)			▶		F
Closing balance of farm losses to be carried forward to future tax years (amount E **minus** amount F)	380				G

Note 8: A farm loss expires as follows:
- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

Note 9: Amount h is the total of lines 340 and 345 from Schedule 3.

Part 4 – Restricted farm losses

Current-year restricted farm loss

Total losses for the year from farming business . . . . **485** ____ A

Minus the deductible farm loss:

(amount A above ____ – $2,500) **divided** by 2 = ____ a

Amount a or $ 15,000 (note 10), whichever is less . . . . ____ ▶ ____ b

2,500 c

Subtotal (amount b **plus** amount c) 2,500 ▶ 2,500 B

Current-year restricted farm loss (amount A **minus** amount B) ____ C

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year . . . . ____ d

Deduct: Restricted farm loss expired (note 11) . . . . **400** ____ e

Restricted farm losses at the beginning of the tax year (amount d **minus** amount e) . . . . **402** ____ ▶ ____ D

Add:

Restricted farm losses transferred on an amalgamation or on the wind-up of a subsidiary corporation . . . . **405** ____ f

Current-year restricted farm loss (from amount C) . . . . **410** ____ g

Enter amount g on line 233 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*.

Subtotal (amount f **plus** amount g) ____ ▶ ____ E

Subtotal (amount D **plus** amount E) ____ F

Deduct:

Restricted farm losses from previous tax years applied against current farming income . . . . . **430** ____ h

Enter amount h on line 333 of the T2 return.

Section 80 – Adjustments for forgiven amounts . . . . **440** ____ i

Other adjustments . . . . **450** ____ j

Subtotal (total of amounts h to j) ____ ▶ ____ G

Restricted farm losses before any request for a carryback (amount F **minus** amount G) ____ H

Deduct – **Request to carry back restricted farm loss to:**

First previous tax year to reduce farming income . . . . **941** ____ k

Second previous tax year to reduce farming income . . . . **942** ____ l

Third previous tax year to reduce farming income . . . . **943** ____ m

Subtotal (total of amounts k to m) ____ ▶ ____ I

Closing balance of restricted farm losses to be carried forward to future tax years (amount H **minus** amount I) **480** ____ J

Note

The total losses for the year from all farming businesses are calculated without including scientific research expenses.

Note 10: For tax years that end before March 21, 2013, use $6,250 instead of $15,000.

Note 11: A restricted farm loss expires as follows:

- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

Part 5 – Listed personal property losses

Continuity of listed personal property loss and request for a carryback

Listed personal property losses at the end of the previous tax year . . . . ______ a

Deduct: Listed personal property loss expired after 7 tax years . . . . **500** ______ b

Listed personal property losses at the beginning of the tax year (amount a **minus** amount b) . . . **502** ______ ▶ ______ A

Add: Current-year listed personal property loss (from Schedule 6) . . . . **510** ______ B

Subtotal (amount A **plus** amount B) ______ C

Deduct:

Listed personal property losses from previous tax years applied against listed personal property gains . . . . **530** ______ c

Enter amount c on line 655 of Schedule 6.

Other adjustments . . . . **550** ______ d

Subtotal (amount c **plus** amount d) ______ ▶ ______ D

Listed personal property losses remaining before any request for a carryback (amount C **minus** amount D) ______ E

Deduct – **Request to carry back listed personal property loss to:**

First previous tax year to reduce listed personal property gains . . . . **961** ______ e

Second previous tax year to reduce listed personal property gains . . . . **962** ______ f

Third previous tax year to reduce listed personal property gains . . . . **963** ______ g

Subtotal (total of amounts e to g) ______ ▶ ______ F

Closing balance of listed personal property losses to be carried forward to future tax years (amount E **minus** amount F) **580** ______ G

Part 7 – Limited partnership losses

Current-year limited partnership losses

	1	2	3	4	5	6	7
	Partnership account number	Tax year ending yyyy/mm/dd	Corporation's share of limited partnership loss	Corporation's at-risk amount	Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses	Column 4 **minus** column 5 (if negative, enter "0")	Current-year limited partnership losses (column 3 **minus** column 6)
	600	**602**	**604**	**606**	**608**		**620**
1.							

Total (enter this amount on line 222 of Schedule 1)

Limited partnership losses from previous tax years that may be applied in the current year

	1	2	3	4	5	6	7
	Partnership account number	Tax year ending yyyy/mm/dd	Limited partnership losses at the end of the previous tax year and amounts transferred on an amalgamation or on the wind-up of a subsidiary	Corporation's at-risk amount	Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses	Column 4 **minus** column 5 (if negative, enter "0")	Limited partnership losses that may be applied in the year (the lesser of columns 3 and 6)
	630	**632**	**634**	**636**	**638**		**650**
1.							

Continuity of limited partnership losses that can be carried forward to future tax years

	1	2	3	4	5	6
	Partnership account number	Limited partnership losses at the end of the previous tax year	Limited partnership losses transferred in the year on an amalgamation or on the wind-up of a subsidiary	Current-year limited partnership losses (from line 620)	Limited partnership losses applied in the current year (must be equal to or less than line 650)	Current year limited partnership losses closing balance to be carried forward to future years (column 2 **plus** column 3 **plus** column 4 **minus** column 5)
	660	**662**	**664**	**670**	**675**	**680**
1.						

Total (enter this amount on line 335 of the T2 return)

Note

If you need more space, you can attach more schedules.

Part 8 – Election under paragraph 88(1.1)(f)

If you are making an election under paragraph 88(1.1)(f), check the box . . . . **190** Yes ☐

In the case of the wind-up of a subsidiary, if the election is made, the non-capital loss, restricted farm loss, farm loss, or limited partnership loss of the subsidiary—that otherwise would become the loss of the parent corporation for a particular tax year starting after the wind–up began—will be considered as the loss of the parent corporation for its immediately preceding tax year and not for the particular year.

Note

This election is only applicable for wind-ups under subsection 88(1) that are reported on Schedule 24, *First-Time Filer after Incorporation, Amalgamation, or Winding-up of a Subsidiary into a Parent*.

Non-Capital Loss Continuity Workchart

Part 6 – Analysis of balance of losses by year of origin

Non-capital losses – losses that can be carried forward over 20 years

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce		Balance at end of year
					Taxable income	Part IV tax	
Current	N/A	1,935,479		272,580	N/A		1,662,899
1st preceding taxation year 2015-12-31		N/A		N/A			
2nd preceding taxation year 2014-12-31		N/A		N/A			
3rd preceding taxation year 2013-12-31		N/A		N/A			
4th preceding taxation year 2012-12-31		N/A		N/A			
5th preceding taxation year 2011-12-31		N/A		N/A			
6th preceding taxation year 2010-12-31		N/A		N/A			
7th preceding taxation year 2009-12-31		N/A		N/A			
8th preceding taxation year 2008-12-31		N/A		N/A			
9th preceding taxation year 2007-12-31		N/A		N/A			
10th preceding taxation year 2006-12-31		N/A		N/A			
11th preceding taxation year 2005-12-31		N/A		N/A			
12th preceding taxation year 2004-12-31		N/A		N/A			
13th preceding taxation year 2003-12-31		N/A		N/A			
14th preceding taxation year 2002-12-31		N/A		N/A			
15th preceding taxation year 2001-12-31		N/A		N/A			
16th preceding taxation year 2000-12-31		N/A		N/A			
17th preceding taxation year		N/A		N/A			
18th preceding taxation year		N/A		N/A			
19th preceding taxation year		N/A		N/A			
20th preceding taxation year		N/A		N/A			*
Total		1,935,479		272,580			1,662,899

* **This balance expires this year and will not be available next year.**

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Schedule 8

Capital Cost Allowance (CCA)

Corporation's name	Business Number	Tax year end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2016-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under *Regulation* 1101(5q)? **101** 1 Yes ☐ 2 No ☒

	1 Class number (See Note)	Description	2 Undepreciated capital cost at the beginning of the year (amount from column 12 of last year's schedule 8)	3 Cost of acquisitions during the year (new property must be available for use)*	4 Adjustments and transfers**	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)***	7 Reduced undepreciated capital cost	8 CCA rate %****	9 Recapture of capital cost allowance***** (line 107 of Schedule 1)	10 Terminal loss (line 404 of Schedule 1)	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1)******	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11)
	200		**201**	**203**	**205**	**207**	**211**		**212**	**213**	**215**	**217**	**220**
1.	1		24,062,604			0		24,062,604	4	0	0	962,504	23,100,100
2.	1	New Building	21,781,126			0		21,781,126	4	0	0	871,245	20,909,881
3.	1b	New Building Additions	64,536	82,630		0	41,315	105,851	6	0	0	6,351	140,815
4.	8	Smart meters	2,179,418	83,653		0	41,827	2,221,244	20	0	0	444,249	1,818,822
5.	47		38,641,855	5,305,233		0	2,652,617	41,294,471	8	0	0	3,303,558	40,643,530
		Totals	86,729,539	5,471,516			2,735,759	89,465,296				5,587,907	86,613,148

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed.
Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see *Regulation* 1100(2) and (2.2).

** Enter in column 4, "Adjustments and transfers", amounts that increase or reduce the undepreciated capital cost. Items that **increase** the undepreciated capital cost include amounts transferred under section 85, or transferred on amalgamation or winding-up of a subsidiary. Items that **reduce** the undepreciated capital cost include government assistance received or entitled to be received in the year, or a reduction of capital cost after the application of section 80. See the *T2 Corporation Income Tax Guide* for other examples of adjustments and transfers to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments and transfers from column 4. For information on the exceptions to the 50% rule, as well as how to calculate the amounts to enter in column 6 in those cases, see Interpretation Bulletin IT-285, *Capital Cost Allowance - General Comments*.

**** Enter a rate only if you are using the declining balance method. For any other method (for example the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** For every entry in column 9, the "Recapture of capital cost allowance" there must be a corresponding entry in column 5, "Proceeds of dispositions during the year". The recapture and terminal loss rules do not apply to passenger vehicles in Class 10.1.

****** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

T2 SCH 8 (14)

Canada

Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

Tax return

Additions for tax purposes – Schedule 8 regular classes		5,471,516			
Additions for tax purposes – Schedule 8 leasehold improvements	+				
Operating leases capitalized for book purposes	+				
Capital gain deferred	+				
Recapture deferred	+				
Deductible expenses capitalized for book purposes – Schedule 1	+				
Other (specify):					
Adjustement for contributed capital	+	450,272			
Transformer inventory adjustment	+	59,774			
Rounding	+				
Total additions per books	=	5,981,562	▶		5,981,562
Proceeds up to original cost – Schedule 8 regular classes					
Proceeds up to original cost – Schedule 8 leasehold improvements	+				
Proceeds in excess of original cost – capital gain	+				
Recapture deferred – as above	+				
Capital gain deferred – as above	+				
Pre V-day appreciation	+				
Other (specify):					
Rounding	+	1			
Total proceeds per books	=	1	▶	–	1
Depreciation and amortization per accounts – Schedule 1				–	4,202,174
Loss on disposal of fixed assets per accounts				–	
Gain on disposal of fixed assets per accounts				+	
Net change per tax return				=	1,779,387

Financial statements

Fixed assets (excluding land) per financial statements

Closing net book value		88,548,076
Opening net book value	–	86,768,689
Net change per financial statements	=	1,779,387

If the amounts from the tax return and the financial statements differ, explain why below.

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2016-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	PUC Inc		89839 7518 RC0001	1					
2.	PUC Services Inc		87626 3526 RC0002	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

T2 SCH 9 (11)

Canada

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2016-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0") .... **200** 2,691,625 A

Add: Cost of eligible capital property acquired during the taxation year **222**

Other adjustments **226**

Subtotal (line 222 plus line 226) x 3 / 4 = B

Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 .... **228** x 1 / 2 = C

amount B minus amount C (if negative, enter "0") ▶ D

Amount transferred on amalgamation or wind-up of subsidiary .... **224** E

Subtotal (add amounts A, D, and E) **230** 2,691,625 F

Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year .... **242** G

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) .... **244** H

Other adjustments .... **246** I

(add amounts G,H, and I) x 3 / 4 = **248** J

Cumulative eligible capital balance (amount F minus amount J) .... 2,691,625 K

(if amount K is negative, enter "0" at line M and proceed to Part 2)

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business **249**

amount K 2,691,625

less amount from line 249

Current year deduction .... 2,691,625 x 7.00 % = **250** 188,414 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 188,414 ▶ 188,414 L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") .... **300** 2,503,211 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)						N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988			**400**		1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)			**401**		2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	**402**		3			
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	**408**		4			
Line 3 minus line 4 (if negative, enter "0")			▶		5	
Total of lines 1, 2 and 5					6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400			7			
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000			8			
Subtotal (line 7 plus line 8)	**409**		▶		9	
Line 6 minus line 9 (if negative, enter "0")					▶	O
Line N minus line O (if negative, enter "0")						P
			Line 5		x 1 / 2 =	Q
Line P minus line Q (if negative, enter "0")						R
			Amount R		x 2 / 3 =	S
Amount N or amount O, whichever is less						T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)					**410**	

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Schedule 23

Agreement Among Associated Canadian-Controlled Private Corporations to Allocate the Business Limit

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* not to be associated for purposes of the small business deduction.

Column 2: Provide the business number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code from the list below that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)
2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 – Associated non-CCPC
5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A.

Ensure that the total at line A does not exceed $500,000.

Allocating the business limit

Date filed (do not use this area) . . . . **025** Year Month Day

Enter the calendar year to which the agreement applies . . . . **050** Year 2016

Is this an amended agreement for the above calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . **075** 1 Yes ☐ 2 No ☒

	1 Names of associated corporations **100**	2 Business number of associated corporations **200**	3 Association code **300**	4 Business limit for the year before the allocation $	5 Percentage of the business limit % **350**	6 Business limit allocated* $ **400**	
1	PUC Distribution Inc.	86709 6778 RC0001	1	500,000			
2	PUC Inc	89839 7518 RC0001	1	500,000	100.0000	500,000	
3	PUC Services Inc	87626 3526 RC0002	1	500,000			
				Total	100.0000	500,000	A

Business limit reduction under subsection 125(5.1) of the Act

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "large corporation amount" at line 415 of the T2 return. The amount at line 415 is determined using the formula 0.225% x (D - $10,000,000). Details of this formula and variable D are in subsection 125(5.1) of the Act.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules for business limit

Special rules apply under subsection 125(5) if a CCPC has more than one tax year ending in the same calendar year and it is associated in more than one of those tax years with another CCPC that has a tax year ending in that calendar year. The business limit for the second or later tax year will be equal to the business limit determined for the first tax year ending in the calendar year or the business limit determined for the second or later tax year ending in the same calendar year, whichever is less.

T2 SCH 23 E (15)

Canada

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Schedule 33

Taxable Capital Employed in Canada – Large Corporations

Corporation's name	Business number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2016-12-31

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- If the total taxable capital employed in Canada of the corporation and its related corporations is greater than $10,000,000, file a completed Schedule 33 with your T2 *Corporation Income Tax Return* no later than six months from the end of the tax year.
- Unless otherwise noted, all legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms **financial institution**, **long-term debt**, and **reserves**.
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, **Taxable capital employed in Canada**.

Part 1 – Capital

Add the following year-end amounts:

Reserves that have not been deducted in calculating income for the year under Part I	101			
Capital stock (or members' contributions if incorporated without share capital)	103	20,062,107		
Retained earnings	104	7,830,504		
Contributed surplus	105			
Any other surpluses	106			
Deferred unrealized foreign exchange gains	107			
All loans and advances to the corporation	108			
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109	65,159,275		
Any dividends declared but not paid by the corporation before the end of the year	110			
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111			
The total of all amounts, each of which is the amount, if any, in respect of a partnership in which the corporation held a membership interest at the end of the year, either directly or indirectly through another partnership (see note below)	112			
Subtotal (**add** lines 101 to 112)		93,051,886	▶ 93,051,886	A

Note:

Line 112 is determined by the formula (A – B) x C/D (as per paragraph 181.2(3)(g)) where:

A is the total of all amounts that would be determined for lines 101, 107, 108, 109, and 111 in respect of the partnership for its last fiscal period that ends at or before the end of the year if
  a) those lines applied to partnerships in the same manner that they apply to corporations, and
  b) those amounts were computed without reference to amounts owing by the partnership
    (i) to any corporation that held a membership interest in the partnership either directly or indirectly through another partnership, or
    (ii) to any partnership in which a corporation described in subparagraph (i) held a membership interest either directly or indirectly through another partnership.

B is the partnership's deferred unrealized foreign exchange losses at the end of the period,

C is the share of the partnership's income or loss for the period to which the corporation is entitled either directly or indirectly through another partnership, and

D is the partnership's income or loss for the period.

Part 1 – Capital (continued)

Subtotal A (from page 1)			93,051,886	A
Deduct the following amounts:				
Deferred tax debit balance at the end of the year	121	1,081,000		
Any deficit deducted in calculating its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122			
To the extent that the amount may reasonably be regarded as being included in any of lines 101 to 112 above for the year, any amount deducted under subsection 135(1) in calculating income under Part I for the year.	123			
Deferred unrealized foreign exchange losses at the end of the year	124			
Subtotal (**add** lines 121 to 124)		1,081,000 ▶	1,081,000	B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")	190		91,970,886	

Part 2 – Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	100,201
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend payable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim or similar obligation of, a partnership each member of which was, throughout the year, another corporation (other than a financial institution) that was not exempt from tax under this Part (otherwise than because of paragraph 181.1(3)(d)), or another partnership described in paragraph 181.2(4)(d.1)	406	
An interest in a partnership (see note 2 below)	407	
Investment allowance for the year (add lines 401 to 407)	490	100,201

Notes:

1. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 (other than a non-resident corporation that at no time in the year carried on business in Canada through a permanent establishment).
2. Where the corporation has an interest in a partnership held either directly or indirectly through another partnership, refer to subsection 181.2(5) for additional rules regarding the carrying value of an interest in a partnership.
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation. Refer to subsection 181.2(6) for special rules that may apply.

Part 3 – Taxable capital

Capital for the year (line 190)		91,970,886	C
Deduct: Investment allowance for the year (line 490)		100,201	D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	91,870,685	

Part 4 – Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500) 91,870,685 x (Taxable income earned in Canada **610** 1,000 / Taxable income 1,000) = **Taxable capital employed in Canada** **690** 91,870,685

Notes:
1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada			**701**	
Deduct the following amounts:				
Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada	**711**			
Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada	**712**			
Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below)	**713**			
Total deductions (**add** lines 711, 712, and 713)		►		E
Taxable capital employed in Canada (line 701 **minus** amount E) (if negative, enter "0")			**790**	

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 – Calculation for purposes of the small business deduction

This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (amount from line 690)		F
Deduct:	10,000,000	G
Excess (amount F **minus** amount G) (if negative, enter "0")		H
Calculation for purposes of the small business deduction (amount H x 0.225%)		I

Enter this amount at line 415 of the T2 return.

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2016-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

Provide only one number per shareholder

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Business Number (If a corporation is not registered, enter "NR") 200	Social insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
1	PUC Inc	89839 7518 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Canada

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Schedule 510

Ontario Corporate Minimum Tax

Corporation's name	Business number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2016-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	114,478,524
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	97,312,067
Total assets (total of lines 112 to 116)		211,790,591
Total revenue of the corporation for the tax year **	142	101,787,208
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	19,000,127
Total revenue (total of lines 142 to 146)		120,787,335

The corporation is subject to CMT if:

– for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.

– for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**

- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**

- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Adjusted net income/loss for CMT purposes

Net income/loss per financial statements *			**210**	-320,437
Add (to the extent reflected in income/loss):				
Provision for current income taxes/cost of current income taxes	**220**			
Provision for deferred income taxes (debits)/cost of future income taxes	**222**	3,000		
Equity losses from corporations	**224**			
Financial statement loss from partnerships and joint ventures	**226**			
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	**230**			
Other additions (see note below):				
Share of adjusted net income of partnerships and joint ventures **	**228**			
Total patronage dividends received, not already included in net income/loss	**232**			
281	**282**			
283	**284**			
Subtotal		3,000 ▶		3,000 A
Deduct (to the extent reflected in income/loss):				
Provision for recovery of current income taxes/benefit of current income taxes	**320**	44,000		
Provision for deferred income taxes (credits)/benefit of future income taxes	**322**			
Equity income from corporations	**324**			
Financial statement income from partnerships and joint ventures	**326**			
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	**330**			
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	**332**			
Gain on donation of listed security or ecological gift	**340**			
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	**342**			
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	**344**			
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	**346**			
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	**348**			
Other deductions (see note below):				
Share of adjusted net loss of partnerships and joint ventures **	**328**			
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	**334**			
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	**336**			
Patronage dividends paid (from Schedule 16) not already included in net income/loss	**338**			
381	**382**			
383	**384**			
385	**386**			
387	**388**			
389	**390**			
Subtotal		44,000 ▶		44,000 B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)			**490**	-361,437

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

- exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
- include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

- Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

- Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.
- Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.
- Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive) . . . . **515** ______

Deduct:

CMT loss available (amount R from Part 7) . . . . ______

Minus: Adjustment for an acquisition of control * . . . . . . **518** ______

Adjusted CMT loss available . . . . ______ ▶ ______ C

Net income subject to CMT calculation (if negative, enter "0") . . . . **520** ______

Amount from line 520 ______ x Number of days in the tax year before July 1, 2010 / Number of days in the tax year ______ / 366 x 4 % = ______ 1

Amount from line 520 ______ x Number of days in the tax year after June 30, 2010 / Number of days in the tax year 366 / 366 x 2.7 % = ______ 2

Subtotal (amount 1 **plus** amount 2) . . . . ______ 3

Gross CMT: amount on line 3 above x OAF ** . . . . **540** ______

Deduct:

Foreign tax credit for CMT purposes *** . . . . **550** ______

CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0") . . . . ______ D

Deduct:

Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) . . . . ______

Net CMT payable (if negative, enter "0") . . . . ______ E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** ______ = ______

Ontario allocation factor . . . . 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

*****Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000".

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year *		135,849	G		
Deduct:					
CMT credit expired *	**600**				
CMT credit carryforward at the beginning of the current tax year * (see note below)		135,849	▶	**620** 135,849	
Add:					
CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below)				**650**	
CMT credit available for the tax year (amount on line 620 **plus** amount on line 650)				135,849	H
Deduct:					
CMT credit deducted in the current tax year (amount P from Part 5)					I
Subtotal (amount H **minus** amount I)				135,849	J
Add:					
Net CMT payable (amount E from Part 3)					
SAT payable (amount O from Part 6 of Schedule 512)					
Subtotal			▶		K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)				**670** 135,849	L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:

- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)					135,849	M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)				1		
For a corporation that is not a life insurance corporation:						
CMT after foreign tax credit deduction (amount D from Part 3)		2				
For a life insurance corporation:						
Gross CMT (line 540 from Part 3)		3				
Gross SAT (line 460 from Part 6 of Schedule 512)		4				
The **greater** of amounts 3 and 4		5				
Deduct: line 2 or line 5, whichever applies:				6		
Subtotal (if negative, enter "0")				▶		N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)						
Deduct:						
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5)						
Subtotal (if negative, enter "0")				▶		O
CMT credit deducted in the current tax year (least of amounts M, N, and O)						P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? **675** 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	CMT credit balance *
10th previous tax year	**680**
9th previous tax year	**681**
8th previous tax year	**682**
7th previous tax year	**683**
6th previous tax year	**684**
5th previous tax year	**685**
4th previous tax year	**686**
3rd previous tax year	**687**
2nd previous tax year	**688**
1st previous tax year	**689**
Total **	

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year *					Q
Deduct:					
CMT loss expired *	**700**				
CMT loss carryforward at the beginning of the tax year * (see note below)			► **720**		
Add:					
CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below)			**750**		
CMT loss available (line 720 **plus** line 750)					R
Deduct:					
CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3)					
Subtotal (if negative, enter "0")					S
Add:					
Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount)			**760**	361,437	
CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760)			**770**	361,437	T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:

- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	**810**	**820**
9th previous tax year	**811**	**821**
8th previous tax year	**812**	**822**
7th previous tax year	**813**	**823**
6th previous tax year	**814**	**824**
5th previous tax year	**815**	**825**
4th previous tax year	**816**	**826**
3rd previous tax year	**817**	**827**
2nd previous tax year	**818**	**828**
1st previous tax year		**829**
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2016-12-31

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
1	PUC Inc	89839 7518 RC0001	62,413,637	2,230,074
2	PUC Services Inc	87626 3526 RC0002	34,898,430	16,770,053
		Total	450 97,312,067	550 19,000,127

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter ¨NR¨ if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

*** Rules for total assets**

- Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
- Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

**** Rules for total revenue**

- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
- Include the associated corporation's share of the total revenue of partnerships and joint ventures.
- If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

Corporate Taxpayer Summary

Corporate information

Corporation's name . . . . PUC Distribution Inc.

Taxation Year . . . . 2016-01-01 to 2016-12-31

Jurisdiction . . . . Ontario

BC	AB	SK	MB	ON	QC	NB	NS	NO	PE	NL	XO	YT	NT	NU	OC
☐	☐	☐	☐	☒	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐

Corporation is associated . . . . Y

Corporation is related . . . . Y

Number of associated corporations . . . 2

Type of corporation . . . . Other Corporation

Total amount due (refund) federal and provincial* . . . . -66,690

* The amounts displayed on lines "Total amount due (refund) federal and provincial" are all listed in the help. Press F1 to consult the context-sensative help.

Summary of federal information

Net income	-1,935,479
Taxable income	
Donations	
Calculation of income from an active business carried on in Canada	
Dividends paid	
Dividends paid – Regular	
Dividends paid – Eligible	
Balance of the low rate income pool at the end of the previous year	
Balance of the low rate income pool at the end of the year	
Balance of the general rate income pool at the end of the previous year	
Balance of the general rate income pool at the end of the year	
Part I tax (base amount)	

Credits against part I tax		**Summary of tax**		**Refunds/credits**	
Small business deduction		Part I		ITC refund	
M&P deduction		Part IV		Dividends refund	
Foreign tax credit		Part III.1		Instalments	66,690
Investment tax credits		Other*		Surtax credit	
Abatement/Other*		Provincial or territorial tax		Other*	

Balance due/refund (–) -66,690

* The amounts displayed on lines "Other" are all listed in the Help. Press F1 to consult the context-sensitive help.

Summary of federal carryforward/carryback information

Carryback amounts

Non-capital losses 272,580

Carryforward balances

Non-capital losses that can be carried forward over 20 years 1,662,899

Cumulative eligible capital 2,503,211

Summary of provincial information – provincial income tax payable

	Ontario	Québec (CO-17)	Alberta (AT1)
Net income	-1,935,479		
Taxable income			
% Allocation	100.00		
Attributed taxable income			
Tax payable before deduction*			
Deductions and credits			
Net tax payable			
Attributed taxable capital	N/A		N/A
Capital tax payable**	N/A		N/A
Total tax payable***			
Instalments and refundable credits			
Balance due/Refund (-)			
Logging tax payable (COZ-1179)			
Tax payable	N/A		N/A

* For Québec, this includes special taxes.

** For Québec, this includes compensation tax and registration fee.

*** For Ontario, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations. The Balance due/Refund is included in the federal Balance due/refund.

Summary of provincial carryforward amounts

Other carryforward amounts

Ontario

Corporate minimum tax credit that can be carried forward over 20 years – Schedule 510	135,849
Corporate minimum tax loss that can be carried forward over 20 years – Schedule 510	361,437

Summary – taxable capital

Federal

Corporate name	Taxable capital used to calculate the business limit reduction (T2, line 415)	Taxable capital used to calculate the SR&ED expenditure limit for a CCPC (Schedules 31 and 49)	Taxable capital used to calculate line 233 of the T2 return	Taxable capital used to calculate line 234 of the T2 return
PUC Distribution Inc.	92,857,725	92,857,725	91,870,685	91,870,685
PUC Inc	73,640	73,640	30,688,870	30,688,870
PUC Services Inc	17,764,362	17,764,362	898,619	898,619
Total	110,695,727	110,695,727	123,458,174	123,458,174

Québec

Corporate name	Paid-up capital used to calculate the Québec business limit reduction (CO-771) and to calculate the additional deduction for transportation costs of remote manufacturing SMEs (CO-156.TR)	Paid-up capital used to calculate the tax credit for investment (CO-1029.8.36.IN)	Paid-up capital used to calculate the 1 million deduction (CO-1137.A and CO-1137.E)
Total			

Ontario

Corporate name	Specified capital used to calculate the expenditure limit – Ontario innovation tax credit (Schedule 566)
Total	

Other provinces

Corporate name	Capital used to calculate the Newfoundland and Labrador capital deduction on financial institutions (Schedule 306)
Total	

Five-Year Comparative Summary

Federal information (T2)

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Taxation year end	**2016-12-31**	**2015-12-31**	**2014-12-31**	**2013-12-31**	**2012-12-31**
Net income	-1,935,479	-682,792	-1,149,357	272,580	1,598,019
Taxable income				272,580	1,598,019
Active business income				272,580	1,579,257
Dividends paid					
Dividends paid – Regular					
Dividends paid – Eligible					
LRIP – end of the previous year					
LRIP – end of the year					
GRIP – end of the previous year					
GRIP – end of the year					
Donations					
Balance due/refund (-)	-66,690	17,261	-175,818	-299,702	-67,882
Line 996 – Amended tax return	☐	☐	☐	☐	☐

Loss carrybacks requested in prior years to reduce taxable income

Taxation year end	**2016-12-31**	**2015-12-31**	**2014-12-31**	**2013-12-31**	**2012-12-31**
Taxable income before loss carrybacks	N/A	N/A		272,580	1,598,019
Non-capital losses	N/A	N/A			682,792
Net capital losses (50%)	N/A	N/A			
Restricted farm losses	N/A	N/A			
Farm losses	N/A	N/A			
Listed personal property losses (50%)	N/A	N/A			
Total loss carried back to prior years	N/A	N/A			682,792
Adjusted taxable income after loss carrybacks	N/A	N/A		272,580	915,227

Losses in the current year carried back to previous years to reduce taxable income (according to Schedule 4)

Taxation year end	**2016-12-31**	**2015-12-31**	**2014-12-31**	**2013-12-31**	**2012-12-31**
Adjusted taxable income before current year loss carrybacks*	N/A			272,580	N/A
Non-capital losses	N/A			272,580	N/A
Net capital losses (50%)	N/A				N/A
Restricted farm losses	N/A				N/A
Farm losses	N/A				N/A
Listed personal property losses (50%)	N/A				N/A
Total current year losses carried back to prior years	N/A			272,580	N/A
Adjusted taxable income after loss carrybacks	N/A				N/A

* The adjusted taxable income before current year loss carryback takes into account loss carrybacks that were made in prior taxation years.

Loss carrybacks requested in prior years to reduce taxable dividends subject to Part IV tax

Taxation year end	2016-12-31	2015-12-31	2014-12-31	2013-12-31	2012-12-31
Adjusted Part IV tax multiplied by the multiplication factor**, before loss carrybacks	N/A	N/A			
Non-capital losses	N/A	N/A			
Farm losses	N/A	N/A			
Total loss carried back to prior years	N/A	N/A			
Adjusted Part IV tax multiplied by the multiplication factor**, after loss carrybacks	N/A	N/A			

Losses in the current year carried back to previous years to reduce taxable dividends subject to Part IV tax (according to Schedule 4)

Taxation year end	2016-12-31	2015-12-31	2014-12-31	2013-12-31	2012-12-31
Adjusted Part IV tax multiplied by the multiplication factor**, before current-year loss carrybacks***	N/A				N/A
Non-capital losses	N/A				N/A
Farm losses	N/A				N/A
Total current year losses carried back to prior years	N/A				N/A
Adjusted Part IV tax multiplied by the multiplication factor**, after loss carrybacks	N/A				N/A

** The multiplication factor is 3 for dividends received before January 1, 2016, and 100 / 38 1/3 for dividends received after December 31, 2015.

*** The adjusted Part IV tax multiplied by the multiplication factor before current-year loss carrybacks takes into account loss carrybacks that were made in prior taxation years. This amount is multiplied by the multiplication factor to help you determine the loss amount that must be used to reduce Part IV tax payable to zero.

Federal taxes

Taxation year end	2016-12-31	2015-12-31	2014-12-31	2013-12-31	2012-12-31
Part I				40,887	239,703
Part IV					
Part III.1					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Credits against part I tax

Taxation year end	2016-12-31	2015-12-31	2014-12-31	2013-12-31	2012-12-31
Small business deduction					
M&P deduction					
Foreign tax credit					
Investment tax credit					
Abatement/other*				62,693	367,544

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Refunds/credits

Taxation year end	2016-12-31	2015-12-31	2014-12-31	2013-12-31	2012-12-31
ITC refund					
Dividend refund					
Instalments	66,690	49,428	199,278	398,555	466,437
Surtax credit					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Ontario

Taxation year end	2016-12-31	2015-12-31	2014-12-31	2013-12-31	2012-12-31
Net income	-1,935,479	-682,792	-1,149,357	272,580	1,598,019
Taxable income				272,580	1,598,019
% Allocation	100.00	100.00	100.00	100.00	100.00
Attributed taxable income				272,580	1,598,019
Surtax					
Income tax payable before deduction				31,347	183,772
Income tax deductions /credits				19,081	24,920
Net income tax payable				12,266	158,852
Taxable capital					
Capital tax payable					
Total tax payable*		66,689	23,460	57,966	158,852
Instalments and refundable credits					
Balance due/refund**		66,689	23,460	57,966	158,852

* For taxation years ending before January 1, 2009, this includes the corporate minimum tax and the premium tax. For taxation years ending after December 31, 2008, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations.

** For taxation years ending after December 31, 2008, the Balance due/Refund is included in the federal Balance due/refund.

Attached Notes – Summary

☐ Name of the cell Federal – Additions – (1/2 year rule) Form Sch. 8 - Capital cost allowance (CCA) workchart

SS-3

sbibeau - 2017-04-04 Keep this note when rolling forward the file ☐

☐ Name of the cell Federal – Additions – (1/2 year rule) Form Sch. 8 - Capital cost allowance (CCA) workchart

SS-3

sbibeau - 2017-04-04 Keep this note when rolling forward the file ☐

☐ Name of the cell Federal – Additions – (1/2 year rule) Form Sch. 8 - Capital cost allowance (CCA) workchart

SS-3

sbibeau - 2017-04-04 Keep this note when rolling forward the file ☐

APPENDIX 9

RDI Full Absorption Cost Allocation

PUC Services Inc.

Full Absorption Cost Allocation Report

Prepared By:

Jim Hopeson

RDI Consulting Inc.
London, Ontario

2007 09 20

rdi consulting inc.

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Appendices

Executive Summary

RDI Consulting Inc. was engaged by PUC Services Inc. to review and make recommendations regarding current processes related to the:

- Allocation of Customer Service costs to Water and Electric
- Allocation of Administrative and General (A&G) costs to all affiliates
- Split of allocated A&G costs between operating costs and capital expenditures of each company
- Split of directly charged A&G costs between operating costs and capital expenditures of each company
- Types of costs included in the current asset use charge
- Allocation of the asset charge to affiliates
- Split of asset charge between operating costs and capital expenditures of each company

The recommendations primarily involve changes in the way the existing pie of costs is sliced between companies and operating and capital activities within the companies.

The recommendations reflect:

- Refinements in the determination of allocation bases used to allocate individual costs, and
- Direction contained in the Accounting Procedures Handbook for regulated Distribution Companies which advocates a fully allocated cost allocation approach (means all businesses and activities should bear a fair share of the indirect costs not able to be specifically charged to a business or an activity)

RDI is recommending that the current asset charge which recovers depreciation only be increased to include the cost of capital related to the investment in the assets used to provide services to all affiliates.

The net effect of all the recommendations results in:

- Operating costs are lower for all businesses except PUC Energies

- Lower operating costs are driven by the following factors
  - Minor change in determination of customer services costs for electric and water
  - Change in allocation of PUC Services A&G costs for all businesses
  - Movement to capital of allocated A&G costs
  - Movement to capital of directly charged A&G costs

  - Change in allocation of existing asset charge recovering depreciation only
  - Increased cost to all businesses resulting from new cost of capital charges as part of the asset use charge

- Lower operating costs for Services primarily driven by new cost of capital revenue source offset by increase in allocated (retained) A&G costs

- Increase in capital costs for all businesses representing the offset to the reduction in Operating expenses

RDI recommends implementing the recommendations in this report effective with the January 1, 2008 fiscal year.

Financial plans and budgets for 2008 as well as the PUC Distribution Inc. 2008 rate rebasing application should be prepared reflecting these recommendations as well.

Introduction

RDI Consulting Inc. was engaged by PUC Services Inc. to review and make recommendations regarding the current processes related to the charging of Customer Service and Administrative and General (A&G) costs to its affiliates. The review also looks at the issue of splitting A&G costs between operating costs and capital expenditures.

In addition the review looks at the current method of charging for the use of vehicles, equipment, and other miscellaneous assets (computers, office furniture, buildings, etc.) required to conduct business.

The treatment of other overhead type expenditures (labour burdens, materials management overheads, vehicle operating costs, engineering, operations supervision) was not part of the scope of the review as Management and RDI agreed that the current processes appropriately allocate costs to individual businesses and operating and capital activities within these businesses.

Fiscal year 2006 financial results were used to assess the directional impact of implementing the recommended changes for all the PUC businesses.

A contributing factor to undertaking the review is the current PUC Distribution Inc. 2008 rate rebasing process. The intent is to apply the recommendations contained in this report to the determination of LDC costs on a forward test year (2008) basis.

Overview of Current Costing Processes

PUC Services Inc. provides financial and accounting services to all affiliates and serves as the gatekeeper in ensuring costs are properly charged to and amongst affiliates.

All transactions occur on a cost pass through basis with no mark-ups.

The Ontario Energy Board prescribed chart of accounts (USOA accounts) is utilized to track costs.

There are 3 different types of costs that are part of the scope of this review and the current treatment is summarized as follows:

Direct Costs

Costs that can be directly identified with a specific business are directly charged. These could be either Customer Service costs or Administrative and General Costs.

Administrative and General Costs are retained as operating costs with no current allocation to capital.

Direct costs using 2006 actuals are set out in Appendix A.

Allocated Costs

Costs that cannot be directly identified with a specific business are allocated to all businesses on a USOA account by account basis using an allocation base that reflects cost drivers or contribution to expenditure. These could be either Customer Service costs or Administrative and General Costs.

Again, Administrative and General Costs are retained as operating costs with no current allocation to capital.

Appendix J provides the current basis for these allocations and the allocation percentages by business stream.

Asset Charge

PUC Services currently allocates depreciation related to Services owned assets (vehicles, equipment, computers, office furniture, buildings, etc.) to all businesses based on their usage of the assets as determined by administration percentages.

Costs are split between operations and capital. The portion related to capital projects is distributed to the projects based on trucking dollars.

No rate of return on invested capital is currently charged.

No depreciation or rate of return is charged on the Queen Street facility as it is a Water owned asset with no book value.

Guidance from Ontario Energy Board Accounting Procedures Handbook

Article 340 of the Accounting Procedures Handbook titled Allocation of Costs and Transfer Pricing provides direction to LDC's regarding cost allocation and charges between affiliated companies.

Some key references from this document are:

The general method for charging indirect costs should be on a fully allocated cost basis.

All costs shall be classified to lines of business, services or products that are regulated, non-regulated, or common to both.

When costs are fully allocated to services and products, the fully allocated cost of the services and products include their direct cost plus a proportional share of indirect costs. Note that fully allocated cost and the term "absorption cost" have the same meaning.

Indirect costs are costs that cannot be identified with a specific unit of product or service or with a specific operation or cost centre. Indirect costs include but are not limited to overhead costs, administrative and general expenses and taxes. Indirect costs are fixed costs that can remain unchanged in total for a given time despite wide fluctuations in activity.

Where an electric utility incurs costs (e.g. general administration, office staff salaries, and rent) jointly with another utility or with its local municipality, the method of splitting the joint costs should be calculated in accordance with some reasonable method of determining a fair and equitable split.

The primary cost driver of common costs, or a relevant proxy in the absence of a primary cost driver, shall be identified and used to allocate the cost between regulated and non-regulated lines of business, products or services.

The methods used in the allocation of costs should be documented and reviewed on a regular basis. If necessary, the cost methods should be revised in order to reflect changes in cost relationships and the related cost allocators. Any changes in the allocation method or the cost allocators used, including the supporting rationale, should be documented and the documentation should be available for Board review.

Where a fair market value is not available for any product, resource or service, a utility shall charge no less than a cost-based price, and shall pay no more than a cost-based price. A cost-based price shall reflect the costs of producing the service or product, including a return on invested capital. The return component shall be the higher of the utility's approved rate of return or the bank prime rate.

Utilities typically charge vehicles/equipment, payroll burdens, and materials management expenses to the key distribution activities that use these resources.

Utilities incur general administration costs that are in support of all business activities:

- Operations
- Maintenance
- Customer billing and collecting
- Construction of capital assets
- Provision of third party services

Under the accounting guidelines these costs should be charged to distribution activities so they absorb their fair share of costs. Proper categorization of operating and capital costs occurs.

Review and Recommendations Re: Costing Processes

Appendix J provides the current basis for and percentages by business stream and Appendix K provides the recommended processes. They are discussed in more detail below.

Direct Charges

Customer Service

Meter Reading USOA account 5310 costs are currently direct charged between Electric and Water on the basis of the relative number of meters (63% electric / 37% Water).

It is recommended that these costs be split on the basis of relative number of meter reads. An analysis of the meter reading contractor bills for 2006 yielded a 57% Electric and 43% Water split.

Administrative and General Costs

It is recommended that all Administrative and General costs directly charged to a specific business be allocated between operations and capital following a review to assess any costs that are not applicable to capital. Net applicable overhead costs should be allocated between operating and capital activities on the relative basis of labour effort incurred. An analysis has been completed for electricity only in determining the impact of this recommendation. Excluded directly incurred A&G costs for PUC Distribution Inc. are set out in Appendix L.

It has been assumed for impact purposes in this document that 100% of directly incurred A&G costs for the other businesses are to be allocated between operations and capital.

Allocated Costs

Customer Service

All the remaining Customer Service USOA accounts (5315 to 5410) are currently split between Electric and Water on the basis of the relative number of customers (56% electric / 44% Water).

This is still a reasonable basis of allocation for all accounts with the exception of the 5321 Account which collects the costs related to the collections group. The existing relative customer count remains at the 56/44 % split.

It is recommended that the cost of the collections group accumulated in USOA 5321 Collections Arrears be allocated between Electric and Water on the basis of the relative bad debt write-offs (76% Electric and 24% Water).

Administrative and General Costs

All Administration and General accounts with the exception of USOA 5675 are currently allocated between the businesses on the basis of an historical FTE work effort review.

The allocation of the 5675 Maintenance of General Plant account is very similar with the exception that no charges are allocated to Telecom as they do not utilize any of the 3 facilities creating slight allocation changes in allocation percentages for the other companies.

All A&G costs allocated to each business remain as operating costs with no allocations to capital.

RDI recommends a similar labour effort based approach utilizing recent work effort data be used to allocate costs to the respective businesses. Appendix I summarizes total work effort data for a recent 12 month period. It is principally comprised of:

- Direct labour hours of bargaining unit employees
- Budgeted labour hours for Management staff
- Estimates of externally contracted labour hours

Collectively it forms a prorate base of total relative effort spent by business unit on both operating and capital activities regardless of the source of the labour effort.

It is also recommended that all Administrative and General costs charged to a specific business be allocated between operations and capital of that business unit using the applicable operating / capital split shown in Appendix I.

Asset Charge

Existing

PUC Services currently allocates depreciation related to Services owned assets (vehicles, equipment, computers, office furniture, buildings, etc.) to all businesses based on their usage of the assets as determined by administration percentages.

Costs are split between operations and capital. The portion related to capital projects is distributed to the projects based on trucking dollars.

Two alternative options were developed for consideration which varied only in the way vehicle and equipment depreciation was allocated:

- Option 1- depreciation on vehicles allocated on the basis of trucking hours and depreciation on other assets allocated on the basis of direct labour hours
- Option 2- depreciation on vehicles allocated on the basis of direct labour hours and depreciation on other assets allocated on the basis of direct labour hours

Appendix G details the results of these options. The results show there is little difference between these 2 options.

It is recommended that Option 1 be used on a go forward basis as it very accurately tracks vehicle and equipment depreciation to the specific activities these assets were used for. In addition, the depreciation on the other assets used to support all business unit operating and capital activities would be allocated on the basis of relative labour effort similar to the recommended approach for Administration and General Costs.

Rate of Return

Currently only depreciation related to PUC Services owned assets is recovered from the users of these assets.

The cost of capital (COC) used to finance the purchase of these assets is not reflected in the recovery by Services. The cost of capital is generally determined based on the financing practices of the business entity (debt / equity split) and the rates of return for both debt and equity.

The Ontario Energy Board which regulates PUC Distribution Inc. allows a rate of return on invested capital to be included in rates and recovered from customers. It is a legitimate part of the full cost of doing business.

Similarly as seen in the APH Section 340 references:

> Where a fair market value is not available for any product, resource or service, a utility shall charge no less than a cost-based price, and shall pay no more than a cost-based price. A cost-based price shall reflect the costs of producing the service or product, including a return on invested capital. The return component shall be the higher of the utility's approved rate of return or the bank prime rate.

RDI recommends that Services recover a cost of capital charge from all the users of the assets that it owns using the LDC deemed weighted average pre-tax cost of capital. As a proxy to assess the impact, a weighted average cost of capital of 7.67% was applied to the December 31, 2006 net book value of Services owned assets. The resulting amounts were allocated using the 2 options discussed above and outlined in Appendix H. This generated an increased recovery amount of $449,833 to be recovered from all businesses. PUC Services use of the assets under Option 1 results in Services retaining $44,817 of costs for a net beneficial impact of $405,016.

The cost of capital for 2006 impact illustration purposes uses the deemed 2008 capital split of 53.3% debt and 46.6 % equity and uses 2006 approved rates of return (debt – 6.35% and equity of 9%)

- 53.3% X 6.35% + 46.7% X 9% = 7.67%
- *Note – after tax return on equity was not grossed up by the tax rate to obtain the pre-tax cost as the income tax rate in the approved 2006 rate application was zero.*

The preparation of 2008 budgets and the forward test year rate application for all PUC corporations should utilize the following calculation of pre-tax cost of capital based on inputs for the 2008 PUC Distribution Inc. rate application:

COC Component	% of Capital Structure	Rate of Return	
Short term debt	4%	4.77%	Pre tax
Long term debt	49.33%	5.82%	Pre tax
Equity	46.67%	8.69%	After tax
Income Tax Rate	36%		

Pre – Tax COC = (4% x 4.77%) + (49.33% x 5.82%) + ((46.67% X (8.69% / 1-.36)

= 9.40%

It is recommended that Option 1 be used to allocate these cost of capital recoveries to be consistent with the recommendation above regarding the allocation of depreciation costs.

Third Party Work Charge-out Rates

RDI recommends that existing charge-out rates for third party work performed by PUC resources be reviewed to ensure alignment with the cost allocation recommendations. Outside parties should also pay their fair share of A&G costs used to support the direct work.

Summary of Impacts

The impacts of all the recommendations for all the PUC businesses using 2006 data are summarized in Appendix M.

The net effect of all the recommendations results in:

- Operating costs are lower for all businesses except PUC Energies
- Lower operating costs are driven by the following factors
    - Minor change in determination of customer services costs for electric and water
    - Change in allocation of Services A&G costs for all businesses
    - Movement to capital of allocated A&G costs
    - Movement to capital of directly charged A&G costs
    - Change in allocation of existing asset charge recovering depreciation only
    - Increased cost to all businesses resulting from new cost of capital charges
- Lower operating costs for Services primarily driven by new cost of capital revenue source offset by increase in allocated (retained) A&G costs
- Increase in capital costs for all businesses representing the offset to the reduction in Operating expenses

Proposed Implementation

RDI recommends implementing the recommendations in this report effective with the January 1, 2008 fiscal year.

Financial plans and budgets for 2008 as well as the PUC Distribution Inc. 2008 rate rebasing application should be prepared reflecting these recommendations as well.

Future Refinement Opportunities

During the course of this review the following allocation process improvement opportunities were identified:

1. No depreciation recoveries or rate of return recoveries on Water owned assets have been identified as asset values are currently not recorded for municipal expenditures.

   The Public Sector Accounting Board of the Canadian Institute of Chartered Accountants has approved revisions to standard PS3150 which requires municipalities to identify, value, and record all their assets on the municipal balance sheet effective 2009.

   The recovery of municipally owned assets should be reassessed at this point in time.

2. USOA account 5410 records the costs associated with the PUC Customer Services Department. PUC will assess the potential to change the Department call tracking process to get better data to more accurately allocate these costs.

3. The determination of total labour effort utilized budgeted time allocations for all Management staff. PUC will assess the implementation of an actual Management staff time tracking process to better allocate costs.

4. The determination of total labour effort also utilized Management estimates of time associated with external contracted services. PUC will assess options to improve resource identification to better allocate costs.

Appendix A
Direct Charges to Businesses ($ 2006)

USOA Account	Account Description	PUC Distribution Inc.	Water	Telecom	Energies
Customer Service Accounts					
5310	Meter Reading	192,047	111,997	0	0
5315	Billing	162,087	0	0	0
5320	Collections	0	0	0	0
5321	Collections Arrears (Bad Debts)	5,263	0	0	0
5325	Collecting - Cash Over/Short	313			
5335	Bad Debt Expense	64,744	22,799	395	
5405	Community Relations Supervision (Call Centre)	0	0	0	0
5410	Community Relations (Call Centre)	63,825	4,089	81,464	0
		488,278	138,885	81,860	0
LDC Only					
5415	Energy Conservation	37,289	0	0	0
5420	Community Safety Program	27,472	0	0	0
		64,762	0	0	0
Business Development					
5510	Business Development	0	0	56,683	11,554
Administration and General Accounts					
5605	Executive Salaries and Expenses	77,411	58,189	6,731	
5610	Management Salaries and Expenses	3,206	8,697	6,467	0
5615	General Administrative Salaries and Expenses	47,841	0	0	
5620	Office Supplies and Expenses	36,148	0	2,680	0
5630	Outside Services Employed	102,382	7,765	6,830	5,813
5635	Property Insurance	51,711	55,224	1,645	870
5645	Pensions and Benefits	(349,831)			
5655	Regulatory Expenses	88,765	0	0	0
5665	Miscellaneous General Expenses	173,610	0	0	0
5675	Maintenance of General Plant	0		36,010	0
		231,244	129,875	60,364	6,683
	Totals	784,284	268,759	198,907	18,236

Appendix B
PUC Services Allocation to PUC Distribution Inc. ($ 2006)

USOA Account	Account Description	PUC Services Costs to be Allocated	Current Percent	Current Dollars	Proposed Percent	Proposed Dollars
Customer Service Accounts						
5310	Meter Reading	304,043	63.00%	191,547	57.48%	174,764
5315	Billing	623,842	56.14%	350,225	56.00%	349,351
5320	Collections	187,339	56.14%	105,172	56.00%	104,910
5321	Collections Arrears (Bad Debts)	163,212	56.14%	91,627	74.00%	120,777
5325	Collecting - Cash Over/Short	(87)	56.14%	(49)	56.00%	(49)
5405	Community Relations Supervision (Call Centre)	39,176	56.14%	21,993	56.00%	21,939
5410	Community Relations (Call Centre)	495,284	56.14%	278,052	56.00%	277,359
		1,812,808		1,038,568		1,049,051
Administration and General Accounts						
5605	Executive Salaries and Expenses	185,402	51.39%	95,278	43.83%	81,262
5610	Management Salaries and Expenses	238,430	51.39%	122,529	43.83%	104,504
5615	General Administrative Salaries and Expenses	660,921	51.39%	339,647	43.83%	289,681
5620	Office Supplies and Expenses	416,726	51.39%	214,156	43.83%	182,651
5630	Outside Services Employed	71,376	51.39%	36,680	43.83%	31,284
5635	Property Insurance	43,469	51.39%	22,339	43.83%	19,053
5665	Miscellaneous General Expenses	7,533	51.39%	3,871	43.83%	3,302
5675	Maintenance of General Plant - Queen St. Facility (water owned)	269,611	51.70%	139,389	43.83%	118,171
5675	Maintenance of General Plant - Services Centre/Trbovich Centre	622,459	51.70%	321,812	43.83%	272,824
		2,515,928		1,295,701		1,102,731
	Totals	4,328,736		2,334,269		2,151,782

Total Dollar Impact (182,487)

Breakdown of Impact

	OM&A	Capital	Total
Increase in Customer Services Costs	10,483		10,483
Reversal of A&G Costs previously charged 100% to Operations	(1,295,701)		(1,295,701)
Allocation of Revised A&G Costs to O&M and Capital (69% O&M and 31% Capital)	760,885	341,847	1,102,731
	(524,333)	341,847	(182,487)
	Decrease	**Increase**	**Decrease**

Appendix C
PUC Services Allocation to Water ($ 2006)

USOA Account	Account Description	PUC Services Costs to be Allocated	Current Percent	Current Dollars	Proposed Percent	Proposed Dollars
Customer Service Accounts						
5310	Meter Reading	304,043	37.00%	112,496	42.52%	129,279
5315	Billing	623,842	43.86%	273,617	44.00%	274,490
5320	Collections	187,339	43.86%	82,167	44.00%	82,429
5321	Collections Arrears (Bad Debts)	163,212	43.86%	71,585	26.00%	42,435
5325	Collecting - Cash Over/Short	(87)	43.86%	(38)	44.00%	(38)
5405	Community Relations Supervision (Call Centre)	39,176	43.86%	17,183	44.00%	17,237
5410	Community Relations (Call Centre)	495,284	43.86%	217,231	44.00%	217,925
		1,812,808		774,240		763,758
Administration and General Accounts						
5605	Executive Salaries and Expenses	185,402	39.20%	72,678	39.97%	74,105
5610	Management Salaries and Expenses	238,430	39.20%	93,464	39.97%	95,300
5615	General Administrative Salaries and Expenses	660,921	39.20%	259,081	39.97%	264,170
5620	Office Supplies and Expenses	416,726	39.20%	163,357	39.97%	166,566
5630	Outside Services Employed	71,376	39.20%	27,979	39.97%	28,529
5635	Property Insurance	43,469	39.20%	17,040	39.97%	17,375
5665	Miscellaneous General Expenses	7,533	39.20%	2,953	39.97%	3,011
5675	Maintenance of General Plant - Queen St. Facility (water owned)	269,611	39.43%	106,308	39.97%	107,764
5675	Maintenance of General Plant - Services Centre/Trbovich Centre	622,459	39.43%	245,436	39.97%	248,797
		2,515,928		988,296		1,005,616
	Totals	4,328,736		1,762,536		1,769,374

Total Dollar Impact 6,838

Breakdown of Impact

	OM&A	Capital	Total
Decrease in Customer Services Costs	(10,483)		(10,483)
Reversal of A&G Costs previously charged 100% to Operations	(988,296)		(988,296)
Allocation of Revised A&G Costs to O&M and Capital (70% O&M and 30% Capital)	703,931	301,685	1,005,616
	(294,847)	301,685	6,838
	Decrease	**Increase**	**Increase**

Appendix D
PUC Services Allocation to Telecom ($ 2006)

USOA Account	Account Description	PUC Services Costs to be Allocated	Current Percent	Current Dollars	Proposed Percent	Proposed Dollars
Administration and General Accounts						
5605	Executive Salaries and Expenses	185,402	0.59%	1,094	0.67%	1,242
5610	Management Salaries and Expenses	238,430	0.59%	1,407	0.67%	1,597
5615	General Administrative Salaries and Expenses	660,921	0.59%	3,899	0.67%	4,428
5620	Office Supplies and Expenses	416,726	0.59%	2,459	0.67%	2,792
5630	Outside Services Employed	71,376	0.59%	421	0.67%	478
5635	Property Insurance	43,469	0.59%	256	0.67%	291
5665	Miscellaneous General Expenses	7,533	0.59%	44	0.67%	50
5675	Maintenance of General Plant - Queen St. Facility (water owned)	269,611	0.00%	-	0.67%	1,806
5675	Maintenance of General Plant - Services Centre/Trbovich Centre	622,459	0.00%	-	0.67%	4,170
		2,515,928		9,581		16,857

Total Dollar Impact 7,276

Breakdown of Impact

	OM&A	Capital	Total
Reversal of A&G Costs previously charged 100% to Operations	(9,581)		(9,581)
Allocation of Revised A&G Costs to O&M and Capital (63% O&M and 37% Capital)	10,620	6,237	16,857
	1,039	6,237	7,276
	Increase	**Increase**	**Increase**

Appendix E
PUC Services Allocation to Energies ($ 2006)

USOA Account	Account Description	PUC Services Costs to be Allocated	Current Percent	Current Dollars	Proposed Percent	Proposed Dollars
Administration and General Accounts						
5605	Executive Salaries and Expenses	185,402	0.00%	-	0.17%	315
5610	Management Salaries and Expenses	238,430	0.00%	-	0.17%	405
5615	General Administrative Salaries and Expenses	660,921	0.00%	-	0.17%	1,124
5620	Office Supplies and Expenses	416,726	0.00%	-	0.17%	708
5630	Outside Services Employed	71,376	0.00%	-	0.17%	121
5635	Property Insurance	43,469	0.00%	-	0.17%	74
5665	Miscellaneous General Expenses	7,533	0.00%	-	0.17%	13
5675	Maintenance of General Plant - Queen St. Facility (water owned)	269,611	0.00%	-	0.17%	458
5675	Maintenance of General Plant - Services Centre/Trbovich Centre	622,459	0.00%	-	0.17%	1,058
		2,515,928		-		4,277

Total Dollar Impact 4,277

Breakdown of Impact

	OM&A	Capital	Total
Reversal of A&G Costs previously charged 100% to Operations	0		0
Allocation of Revised A&G Costs to O&M and Capital (83% O&M and 17% Capital)	3,550	727	4,277
	3,550	727	4,277
	Increase	**Increase**	**Increase**

Appendix F
PUC Services Administration and General Costs Retained ($ 2006)

USOA Account	Account Description	PUC Services Costs to be Allocated	Current Percent	Current Dollars	Proposed Percent	Proposed Dollars
Administration and General Accounts						
5605	Executive Salaries and Expenses	185,402	8.82%	16,352	15.37%	28,496
5610	Management Salaries and Expenses	238,430	8.82%	21,029	15.37%	36,647
5615	General Administrative Salaries and Expenses	660,921	8.82%	58,293	15.37%	101,583
5620	Office Supplies and Expenses	416,726	8.82%	36,755	15.37%	64,051
5630	Outside Services Employed	71,376	8.82%	6,295	15.37%	10,970
5635	Property Insurance	43,469	8.82%	3,834	15.37%	6,681
5665	Miscellaneous General Expenses	7,533	8.82%	664	15.37%	1,158
5675	Maintenance of General Plant - Queen St. Facility (water owned)	269,611	8.82%	23,780	15.37%	41,439
5675	Maintenance of General Plant - Services Centre/Trbovich Centre	622,459	8.82%	54,901	15.37%	95,672
		2,515,928		221,905		386,698

Total Dollar Impact 164,793

Breakdown of Impact

	OM&A	Capital	Total
Reversal of A&G Costs previously charged 100% to Operations	(221,905)		(221,905)
Allocation of Revised A&G Costs to O&M and Capital (96% O&M and 4% Capital)	371,230	15,468	386,698
	149,325	15,468	164,793
	Increase	**Increase**	**Increase**

Appendix G
Analysis of Asset Ccharge

			Electric Capital	Electric Expense	Water Capital	Water Expense	Services Capital	Services Admn	Services Expense	Services Third Party	Telecom Capital	Telecom Expense	Energies Capital	Energies Expense		TOTAL
In 2006 allocated			**$ 120,123.57**	**$ 286,015.24**	**$ 21,995.63**	**$ 291,585.52**	**$ 6,386.79**		**$ 70,793.36**		**$ 322.46**					**$ 797,222.57**
If using Vehicle hours & General Allocations		veh hr	$ 241,541.77	$ 198,279.47	$ 47,482.07	$ 200,917.08	$ 11,388.10	$ 17,201.18	$ 5,992.35	$ 71,570.25	$ 810.00	$ 41.65	$ 292.23	$ 1,706.42		$ 797,222.57
		Gen														
Effect of change	Increase to Capital		$ 121,418.20		$ 25,486.44		$ 5,001.31			$ 71,570.25	$ 487.54		$ 292.23			
	Decrease to Expense			$ (87,735.77)		$ (90,668.44)			$ (64,801.02)							
	Increase to Expense							$ 17,201.18				$ 41.65		$ 1,706.42		
If using DL hours & General Allocations		DL hr	$ 244,873.72	$ 201,486.47	$ 49,689.49	$ 209,663.45	$ 12,179.44	$ -	$ 161.44	$ 75,651.88	$ 643.40	$ -	$ 458.83	$ 2,414.46		$ 797,222.57
		Gen														
Effect of change	Increase to Capital		$ 124,750.15		$ 27,693.86		$ 5,792.65				$ 320.94		$ 458.83			
	Decrease to Expense			$ (84,528.77)		$ (81,922.07)			$ (70,631.93)							
	Increase to Expense									$ 75,651.88				$ 2,414.46		

Analysis of Vehicles--Asset charge

	Electric Capital	Electric Expense	Water Capital	Water Expense	Services Capital	Services Admn	Services Expense	Services Third Party	Telecom Capital	Telecom Expense	Energies Capital	Energies Expense	
Method 1													
By Trucking hours	27.28%	23.38%	6.44%	27.07%	1.28%	4.13%	1.42%	8.76%	0.12%	0.01%	0.01%	0.10%	100.00%
Method 2													
By direct labour	28.08%	24.15%	6.97%	29.17%	1.47%	0%	0.02%	9.74%	0.08%	0%	0.05%	0.27%	100.00%
Total Vehicle depreciation for 2006	$ 416,493.55												
Method 1													
$ by trucking hours	$ 113,619.44	$ 97,376.19	$ 26,822.18	$ 112,744.80	$ 5,331.12	$ 17,201.18	$ 5,914.21	$ 36,484.83	$ 499.79	$ 41.65	$ 41.65	$ 416.49	$ 416,493.55
Allocate Servcies admn $17,201.18	$ 3,182.22	$ 4,695.92	$ 774.05	$ 5,143.15	$ 172.01	$ (17,201.18)	$ -	$ 3,147.82	$ 51.60	$ -	$ -	$ 34.40	$ (0.00)
	$ 116,801.66	$ 102,072.12	$ 27,596.24	$ 117,887.96	$ 5,503.13	$ -	$ 5,914.21	$ 39,632.65	$ 551.40	$ 41.65	$ 41.65	$ 450.90	$ 416,493.55
Method 2													
$ by direct lab hours	$ 116,951.39	$ 100,583.19	$ 29,029.60	$ 121,491.17	$ 6,122.46	$ -	$ 83.30	$ 40,566.47	$ 333.19	$ -	$ 208.25	$ 1,124.53	$ 416,493.55

Other Services assets	**2006 depreciation**	**Allocator**	Electric Capital	Electric Expense	Water Capital	Water Expense	Services Capital	Services Admn	Services Expense	Services Third Party	Telecom Capital	Telecom Expense	Energies Capital	Energies Expense	
Major tools & Equipment (Electric)	$ 79,909.20	Line dept DL	$ 41,933.69	$ 28,561.56	$ 7.70	$ 151.20	$ 1,672.84		$ 19.26	$ 6,941.76	$ 75.12	$ -	$ 93.42	$ 452.64	$ 79,909.20
Major tools & Equipment (Water)	$ 5,370.69	Water Dept DL	$ 23.37	$ 42.06	$ 861.15	$ 4,440.03				$ 4.09					$ 5,370.69
Communications Equipment	$ 26,433.34	Pooled %	$ 7,422.48	$ 6,383.65	$ 1,842.40	$ 7,710.61	$ 388.57	$ -	$ 5.29	$ 2,574.61	$ 21.15	$ -	$ 13.22	$ 71.37	$ 26,433.34
Radio /Pager equipment (Water)	$ 948.43	Water Dept DL	$ 4.13	$ 7.43	$ 152.07	$ 784.08				$ 0.72					$ 948.43
System Supervisory	$ 1,031.92	Pooled %	$ 289.76	$ 249.21	$ 71.92	$ 301.01	$ 15.17	$ -	$ 0.21	$ 100.51	$ 0.83	$ -	$ 0.52	$ 2.79	$ 1,031.92
General Office Equipment (Electric)	$ 17,607.19	Line dept DL	$ 9,239.67	$ 6,293.25	$ 1.70	$ 33.32	$ 368.59		$ 4.24	$ 1,529.55	$ 16.55	$ -	$ 20.58	$ 99.73	$ 17,607.19
General Office Equipment (Water)	$ 3,726.66	Water Dept DL	$ 16.22	$ 29.18	$ 597.54	$ 3,080.88				$ 2.84					$ 3,726.66
Computer Hardware	$ 104,002.38	Pooled %	$ 29,203.87	$ 25,116.57	$ 7,248.97	$ 30,337.49	$ 1,528.83	$ -	$ 20.80	$ 10,129.83	$ 83.20	$ -	$ 52.00	$ 280.81	$ 104,002.38
Computer Software	$ 71,468.76	Pooled %	$ 20,068.43	$ 17,259.71	$ 4,981.37	$ 20,847.44	$ 1,050.59	$ -	$ 14.29	$ 6,961.06	$ 57.18	$ -	$ 35.73	$ 192.97	$ 71,468.76
Stores equipment	$ 20,907.41	Pooled %	$ 5,870.80	$ 5,049.14	$ 1,457.25	$ 6,098.69	$ 307.34	$ -	$ 4.18	$ 2,036.38	$ 16.73	$ -	$ 10.45	$ 56.45	$ 20,907.41
Service Centre	$ 49,323.04	Pooled %	$ 13,849.91	$ 11,911.51	$ 3,437.82	$ 14,387.53	$ 725.05	$ -	$ 9.86	$ 4,804.06	$ 39.46	$ -	$ 24.66	$ 133.17	$ 49,323.04
	$ 380,729.02	**TOTAL**	**$ 127,922.33**	**$ 100,903.28**	**$ 20,659.89**	**$ 88,172.28**	**$ 6,056.99**	**$ -**	**$ 78.14**	**$ 35,085.41**	**$ 310.20**	**$ -**	**$ 250.58**	**$ 1,289.92**	**$ 380,729.02**

Total depreciation in Services to be allocated in 2006			
Vehicles		$ 416,493.55	
Other assets (above)		$ 380,729.02	
		$ 797,222.57	
In 2006 the asset charge was allocated as follows:			
First			
Distribution (expense)	51.69%	$ 412,084.35	
Water (expense)	39.43%	$ 314,344.86	
Servcies (expense)	8.88%	$ 70,793.36	
		$ 797,222.57	
Then re-distributed to capital and the final result was:			
Electric capital		$ 120,123.57	15.07%
Electric expense		$ 286,015.24	35.88%
Water capital		$ 21,995.63	2.76%
Water expense		$ 291,585.52	36.58%
Services capital		$ 6,386.79	0.80%
Services expense		$ 70,793.36	8.88%
Telecom capital		$ 322.46	0.04%
Telecom expense		$ -	
Energies capital		$ -	
Energies expense		$ -	
		$ 797,222.57	100.00%

Appendix H
Analysis of Rate of Return Calculation

			Electric Capital	Electric Expense	Water Capital	Water Expense	Services Capital	Services Admn	Services Expense	Services Third Party	Telecom Capital	Telecom Expense	Energies Capital	Energies Expense		TOTAL
In 2006 allocated			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**0**	**$ -**	**0**	**$ -**	**0**	**0**	**0**		**$ -**
If using Vehicle hours & General Allocations			$ 141,508.31	$ 119,119.81	$ 27,268.65	$ 108,616.47	$ 6,817.55	$ 4,024.45	$ 2,170.39	$ 38,622.48	$ 277.81	$ 3.05	$ 200.08	$ 1,204.01		$ 449,833.05
Effect of change	Increase to Capital		$ 141,508.31		$ 27,268.65		$ 6,817.55			$ 38,622.48	$ 277.81		$ 200.08			
	Increase to Expense			$ 119,119.81		$ 108,616.47			$ 2,170.39							
	Increase to Expense							$ 4,024.45				$ 3.05		$ 1,204.01		
If using DL hours & General Allocations			$ 138,803.07	$ 113,854.31	$ 27,872.27	$ 117,823.89	$ 6,878.33	$ -	$ 90.99	$ 42,515.73	$ 362.55	$ -	$ 260.97	$ 1,370.92		$ 449,833.05
Effect of change	Increase to Capital		$ 138,803.07		$ 27,872.27		$ 6,878.33				$ 362.55		$ 260.97			
	Increase to Expense			$ 113,854.31		$ 117,823.89			$ 90.99							
	Increase to Expense									$ 42,515.73				$ 1,370.92		

Additional revenue to Services

If using Vehicle hours & General Allocations

Total rate of return	$ 449,833.05
Less: Services keeps	$ 44,817.32
	$ 405,015.73

If using DL hours & General Allocations

Total rate of return	$ 449,833.05
Less: Services keeps	$ 42,606.72
	$ 407,226.33

Analysis of Vehicles--Rate of return on assets

	Electric Capital	Electric Expense	Water Capital	Water Expense	Services Capital	Services Admn	Services Expense	Services Third Party	Telecom Capital	Telecom Expense	Energies Capital	Energies Expense	
Method 1													
By Trucking hours	29.81%	27.52%	6.58%	23.28%	1.43%	2.57%	1.35%	7.25%	0.03%	0.00200%	0.01%	0.16%	100.00%
Method 2													
By direct labour	28.08%	24.15%	6.97%	29.17%	1.47%	0%	0.02%	9.74%	0.08%	0%	0.05%	0.27%	100.00%
NBV of vehicles Jan 1 2006	$ 2,039,573.25												
Apply rate of return @ 7.67%	$ 156,435.27												
Method 1													
$ by trucking hours	$ 46,632.26	$ 43,044.62	$ 10,299.92	$ 36,424.75	$ 2,238.81	$ 4,024.45	$ 2,110.68	$ 11,343.55	$ 40.40	$ 3.05	$ 17.32	$ 255.46	$ 156,435.27
Allocate Servcies admn $17,201.18	$ 744.52	$ 1,098.67	$ 181.10	$ 1,203.31	$ 40.24	$ (4,024.45)	$ -	$ 736.47	$ 12.07	$ -	$ -	$ 8.05	$ (0.00)
	$ 47,376.78	$ 44,143.29	$ 10,481.02	$ 37,628.06	$ 2,279.05	$ -	$ 2,110.68	$ 12,080.02	$ 52.47	$ 3.05	$ 17.32	$ 263.51	$ 156,435.27
Method 2													
$ by direct lab hours	$ 43,927.02	$ 37,779.12	$ 10,903.54	$ 45,632.17	$ 2,299.60	$ -	$ 31.29	$ 15,236.80	$ 125.15	$ -	$ 78.22	$ 422.38	$ 156,435.27

Other Services assets	**Opening NBV Jan 1 2006**	**7.67% Rate of return**	**Allocator**	**Electric Capital**	**Electric Expense**	**Water Capital**	**Water Expense**	**Services Capital**	**Services Admn**	**Services Expense**	**Services Third Party**	**Telecom Capital**	**Telecom Expense**	**Energies Capital**	**Energies Expense**	
Major tools & Equipment (Electric)	$ 506,185.69	$ 38,824.44	Line dept DL	$ 20,373.78	$ 13,876.83	$ 3.74	$ 73.46	$ 812.76		$ 9.36	$ 3,372.70	$ 36.50	$ -	$ 45.39	$ 219.92	$ 38,824.44
Major tools & Equipment (Water)	$ 32,659.05	$ 2,504.95	Water Dept DL	$ 10.90	$ 19.62	$ 401.65	$ 2,070.88				$ 1.91					$ 2,504.95
Communications Equipment	$ 212,454.01	$ 16,295.22	Pooled %	$ 4,575.70	$ 3,935.30	$ 1,135.78	$ 4,753.32	$ 239.54	$ -	$ 3.26	$ 1,587.15	$ 13.04	$ -	$ 8.15	$ 44.00	$ 16,295.22
Radio /Pager equipment (Water)	$ 2,425.08	$ 186.00	Water Dept DL	$ 0.81	$ 1.46	$ 29.82	$ 153.77				$ 0.14					$ 186.00
System Supervisory	$ 9,279.51	$ 711.74	Pooled %	$ 199.86	$ 171.88	$ 49.61	$ 207.61	$ 10.46	$ -	$ 0.14	$ 69.32	$ 0.57	$ -	$ 0.36	$ 1.92	$ 711.74
General Office Equipment (Electric)	$ 264,564.70	$ 20,292.11	Line dept DL	$ 10,648.63	$ 7,252.91	$ 1.96	$ 38.40	$ 424.80		$ 4.89	$ 1,762.79	$ 19.08	$ -	$ 23.72	$ 114.94	$ 20,292.11
General Office Equipment (Water)	$ 56,057.06	$ 4,299.58	Water Dept DL	$ 18.71	$ 33.67	$ 689.40	$ 3,554.52				$ 3.28					$ 4,299.58
Computer Hardware	$ 530,434.13	$ 40,684.30	Pooled %	$ 11,424.15	$ 9,825.26	$ 2,835.70	$ 11,867.61	$ 598.06	$ -	$ 8.14	$ 3,962.65	$ 32.55	$ -	$ 20.34	$ 109.85	$ 40,684.30
Computer Software	$ 163,222.26	$ 12,519.15	Pooled %	$ 3,515.38	$ 3,023.37	$ 872.58	$ 3,651.84	$ 184.03	$ -	$ 2.50	$ 1,219.36	$ 10.02	$ -	$ 6.26	$ 33.80	$ 12,519.15
Stores equipment	$ 225,790.74	$ 17,318.15	Pooled %	$ 4,862.94	$ 4,182.33	$ 1,207.08	$ 5,051.70	$ 254.58	$ -	$ 3.46	$ 1,686.79	$ 13.85	$ -	$ 8.66	$ 46.76	$ 17,318.15
Service Centre	$ 1,822,192.17	$ 139,762.14	Pooled %	$ 39,245.21	$ 33,752.56	$ 9,741.42	$ 40,768.62	$ 2,054.50	$ -	$ 27.95	$ 13,612.83	$ 111.81	$ -	$ 69.88	$ 377.36	$ 139,762.14
	$ 3,825,264.40	**$ 293,397.78**	**TOTAL**	**$ 94,876.05**	**$ 76,075.19**	**$ 16,968.73**	**$ 72,191.72**	**$ 4,578.74**	**$ -**	**$ 59.71**	**$ 27,278.93**	**$ 237.41**	**$ -**	**$ 182.76**	**$ 948.55**	**$ 293,397.78**

Appendix I
PUC Labour Hours Summary

	Direct Labour	Mgt Labour (Indirect)	Customer Service Direct	Customer Service Allocated	Externally Contracted Services	Total	Work Activity %	O&M/ Capital Split	Total Business %	
Water Capital	6,802.50	2,646.00			21,166.00	30,614.50	12.01%	30%	39.97%	*Water*
Water Operating & Mtce	44,876.75	10,049.80	257.00	9,082.20	6,991.00	71,256.75	27.96%	70%		
PUC Distribution- Capital & CDM	27,613.00	5,024.97			2,350.00	34,987.97	13.73%	31%	43.83%	*LDC*
PUC Distribution Operating & Mtce	41,035.75	6,026.80	1,869.50	11,625.05	16,160.00	76,717.10	30.10%	69%		
PUC Services - Capital	1,489.00				109.00	1,598.00	0.63%	4%	15.37%	*Services*
PUC Servcies Operating & Mtce	74.50					74.50	0.03%			
PUC Services - Contract Work	27,476.00	6,643.44			3,374.00	37,493.44	14.71%	96%		
Telecom Operating & Mtce	73.00	293.80			711.00	1,077.80	0.42%	63%	0.67%	*Telecom*
PUC Telecom capital	377.00				246.00	623.00	0.24%	37%		
PUC Energies Capital	71.50				-	71.50	0.03%	17%	0.17%	*Energies*
PUC Energies Operating & Mtce	300.50	61.10			-	361.60	0.14%	83%		
	150,189.50	**30,745.91**	**2,126.50**	**20,707.25**	**51,107.00**	**254,876.16**	**100%**		**100%**	

Appendix J
Current Allocation Factors (Services Costs Not Able To Be Directly Charged)

USOA Account	Account Description	PUC Distribution Inc.	Water	Telecom	Energies	Services	Total	Allocation Basis
Customer Service Accounts								
5310	Meter Reading	63.00%	37.00%				100%	Relative number of meters
5315	Billing	56.14%	43.86%				100%	Relative number of customers
5320	Collections	56.14%	43.86%				100%	Relative number of customers
5321	Collections Arrears (Bad Debts)	56.14%	43.86%				100%	Relative number of customers
5325	Collecting - Cash Over/Short	56.14%	43.86%				100%	Relative number of customers
5405	Community Relations Supervision (Call Centre)	56.14%	43.86%				100%	Relative number of customers
5410	Community Relations (Call Centre)	56.14%	43.86%				100%	Relative number of customers
Administration and General Accounts								
5605	Executive Salaries and Expenses	51.39%	39.20%	0.59%	0.00%	8.82%	100%	Relative FTEs identified by business
5610	Management Salaries and Expenses	51.39%	39.20%	0.59%	0.00%	8.82%	100%	Relative FTEs identified by business
5615	General Administrative Salaries and Expenses	51.39%	39.20%	0.59%	0.00%	8.82%	100%	Relative FTEs identified by business
5620	Office Supplies and Expenses	51.39%	39.20%	0.59%	0.00%	8.82%	100%	Relative FTEs identified by business
5630	Outside Services Employed	51.39%	39.20%	0.59%	0.00%	8.82%	100%	Relative FTEs identified by business
5635	Property Insurance	51.39%	39.20%	0.59%	0.00%	8.82%	100%	Relative FTEs identified by business
5645	Pensions and Benefits	51.39%	39.20%	0.59%	0.00%	8.82%	100%	Relative FTEs identified by business
5655	Regulatory Expenses	51.39%	39.20%	0.59%	0.00%	8.82%	100%	Relative FTEs identified by business
5665	Miscellaneous General Expenses	51.39%	39.20%	0.59%	0.00%	8.82%	100%	Relative FTEs identified by business
5675	Maintenance of General Plant	51.70%	39.43%	0.00%	0.00%	8.82%	100%	Relative FTEs identified by business modified by removing Telecom as they do not use any of the facilites

Appendix K
Proposed Allocation Factors (Services Costs Not Able To Be Directly Charged)

USOA Account	Account Description	PUC Distn. Inc.	Water	Telecom	Energies	Services	Total	Allocation Basis
Customer Service Accounts								
5310	Meter Reading	57.48%	42.52%				100%	Option 1 - Relative number of meter reads per 2006 contractor billings
		56.00%	44.00%					Option 2 - Relative number of customers at December 31, 2006
5315	Billing	56.00%	44.00%				100%	Relative number of customers at December 31, 2006
5320	Collections	56.00%	44.00%				100%	Relative number of customers at December 31, 2006
5321	Collections Arrears (Bad Debts)	74.00%	26.00%				100%	Option 1 - Relative bad debt expense (3 yr average)
		56.00%	44.00%					Option 2 - Relative number of customers at December 31, 2006
5325	Collecting - Cash Over/Short	56.00%	44.00%				100%	Relative number of customers at December 31, 2006
5405	Community Relations Supervision (Ca	56.00%	44.00%				100%	Relative number of customers at December 31, 2006
5410	Community Relations (Call Centre)	56.00%	44.00%				100%	Relative number of customers at December 31, 2006
Administration and General Accounts								
5605	Executive Salaries and Expenses	43.83%	39.97%	0.67%	0.17%	15.37%	100%	Relative Work Effort Identified By Labour Hours
5610	Management Salaries and Expenses	43.83%	39.97%	0.67%	0.17%	15.37%	100%	Relative Work Effort Identified By Labour Hours
5615	General Administrative Salaries and E	43.83%	39.97%	0.67%	0.17%	15.37%	100%	Relative Work Effort Identified By Labour Hours
5620	Office Supplies and Expenses	43.83%	39.97%	0.67%	0.17%	15.37%	100%	Relative Work Effort Identified By Labour Hours
5630	Outside Services Employed	43.83%	39.97%	0.67%	0.17%	15.37%	100%	Relative Work Effort Identified By Labour Hours
5635	Property Insurance	43.83%	39.97%	0.67%	0.17%	15.37%	100%	Relative Work Effort Identified By Labour Hours
5645	Pensions and Benefits	43.83%	39.97%	0.67%	0.17%	15.37%	100%	Relative Work Effort Identified By Labour Hours
5655	Regulatory Expenses	43.83%	39.97%	0.67%	0.17%	15.37%	100%	Relative Work Effort Identified By Labour Hours
5665	Miscellaneous General Expenses	43.83%	39.97%	0.67%	0.17%	15.37%	100%	Relative Work Effort Identified By Labour Hours
5675	Maintenance of General Plant	43.83%	39.97%	0.67%	0.17%	15.37%	100%	Relative Work Effort Identified By Labour Hours

Appendix L
PUC Distribution Inc.
Administrative and General Costs Excluded From Allocation to Capital

Account #	Description	2006 Actual	2006 exclusions
01.5605.1000.01.0003	Adm & Gen Exec Indir Lab	$ 53,859.80	$ -
01.5605.1000.01.0004	Admin & Gen Exec Lab OH	$ 11,925.80	$ -
01.5605.1000.04.0110	Admin & Gen Exec Registrt	$ 2,065.00	$ 2,065.00
01.5605.1000.04.0111	Admin & Gen Exec Transpor	$ 4,641.11	$ 4,641.11
01.5605.1000.04.0112	Admin & Gen Exec Meals	$ 407.26	$ 407.26
01.5605.1000.04.0113	Admin & Gen Exec Accomodt	$ 920.88	$ 920.88
01.5605.1000.04.0999	Admin & Gen Exec Misc	$ (69.00)	$ (69.00)
01.5605.1049.04.0111	Admin & Gen Exec Travel	$ 1,844.00	$ 1,844.00
01.5605.1100.01.0005	Board Salaries	$ 1,158.33	$ -
01.5605.2000.04.0110	Admn & Gen Exec Regist	$ 625.00	$ 625.00
01.5605.2000.04.0111	Admin & Gen Exec Travel	$ 32.71	$ 32.71
01.5610.2200.04.0112	Adm Mgmt Sal/Exp Meals	$ 38.76	$ 38.76
01.5610.3000.01.0003	Adm Mgmt Salary Indir Lab	$ 56.50	$ 56.50
01.5610.3000.01.0004	Admin Mgmt Salary Lab OH	$ 12.51	$ 12.51
01.5610.3000.04.0999	Adm Mgmt Sal/Exp Misc	$ 10.00	$ 10.00
01.5610.4000.04.0111	Admn Mgmt Sal Travel	$ 617.06	$ 617.06
01.5610.4044.04.0110	Adm Mgmt Sal/Exp Registrt	$ 313.00	$ 313.00
01.5610.5000.04.0111	Adm Mgmt Sal/Exp Travel	$ 1,330.08	$ 1,330.08
01.5610.5000.04.0112	Adm Mgmt Sal/Exp Meals	$ 74.51	$ 74.51
01.5610.5044.04.0110	Adm Mgmt Sal/Exp Registrt	$ 250.00	$ 250.00
01.5610.5144.04.0112	Adm Mgmt Sal/Exp Meals	$ 39.62	$ 39.62
01.5610.5144.04.0113	Adm Mgmt Accommodations	$ 463.58	$ 463.58
01.5615.1000.01.0003	Adm Gen Sal/Exp Indir Lab	$ 23,734.28	$ -
01.5615.1000.01.0004	Admin Gen Sal/Exp Lab OH	$ 5,255.36	$ -
01.5615.4100.01.0002	Admin Gen Salary Lab OH	$ 18,851.54	$ 18,851.54
01.5620.4100.04.0175	Adm Office Bank Charges	$ 37,500.00	$ 37,500.00
01.5620.4100.04.0999	Admin Office Misc	$ (1,351.78)	
01.5630.1000.04.0111	Admin Outside Serv Travel	$ 26.49	$ 26.49
01.5630.1000.04.0112	Admin Outside Serv Meals	$ 17.23	$ 17.23
01.5630.1000.04.0113	Admin O/S Serv Accomodatn	$ 368.68	$ 368.68
01.5630.1000.04.0405	Admin O/S Serv Legal Fees	$ 875.00	$ 875.00
01.5630.1000.04.0410	Admin O/S Serv Consulting	$ 24,050.00	$ 24,050.00
01.5630.1000.04.0999	Admin Outside Serv Misc	$ 453.07	
01.5630.4000.04.0410	Admin O/S Tax Consult	$ 5,920.00	
01.5630.4000.04.0405	Admin O/S Serv Legal Fees	$ 68,485.58	$ 68,485.58
01.5630.4100.04.0999	Adm Outside Serv Misc	$ 1,150.00	
01.5630.5000.04.0410	Admin O/S Serv Consulting	$ 800.00	
01.5630.5100.04.0405	Adm O/S Serv Legal Fees	$ 235.00	
01.5635.3400.04.0600	Admin Property Insurance	$ 51,711.49	$ 51,711.49
01.5655.1000.04.0111	Adm Regulatory Exp Travel	$ 618.00	
01.5655.1000.04.0999	Admin Regulatory Expenses	$ 60,364.25	
01.5655.2100.01.0001	Adm Regulatory Ex Dir Lab	$ 1,085.84	
01.5655.2100.01.0002	Adm Regulatory Exp Lab OH	$ 433.41	
01.5655.2100.03.0001	Adm Regulatory Exp Truck	$ 70.81	
01.5655.3098.04.0410	Admin Reg Exp Consulting	$ 7,861.88	$ 7,861.88
01.5655.3400.04.0105	Adm Regulatory Stationary	$ 1,507.68	
01.5655.3400.04.0260	Adm Regulatory Sault Star	$ 2,493.30	
01.5655.3400.04.0263	Adm Regulatory Alrick	$ 722.10	
01.5655.4000.04.0111	Admn regulatory Travel	$ 707.73	
01.5655.4000.04.0405	Adm Regulatory Legal	$ 1,320.01	
01.5655.4000.04.0410	Adm Regulatory Consulting	$ 5,500.00	
01.5655.4000.04.0999	Adm Regulatory Misc	$ 5,646.78	$ 1,000.00
01.5655.5100.01.0001	Adm Regulatory Ex Dir Lab	$ 431.65	
01.5655.5100.01.0002	Adm Regulatory Exp Lab OH	$ 1.78	
01.5665.1000.04.0330	Adm Misc Indust Assn Dues	$ 44,100.00	
01.5665.3100.01.0003	Adm Mis Gen Exp Indir Lab	$ 9,164.03	$ 9,164.03
01.5665.3100.01.0004	Admin Misc Gen Exp Lab OH	$ 2,029.15	$ 2,029.15
01.5665.4000.01.0003	Adm Mis Gen Exp Indir Lab	$ 92,774.68	
01.5665.4000.01.0004	Admin Misc Gen Exp Lab OH	$ 20,542.51	
01.5665.5100.04.0321	Admin Misc Exp Co Mmbrshp	$ 5,000.00	
		$ 581,074.04	***$ 235,613.65***

Appendix M
Summary of Costing Changes

	LDC	Water	Telecom	Energies	Services
Operating , Maintenance and Administration Expenses					
Change in Allocation of Customer Service Costs and A&G Costs (Appendices B to F)	(524,333)	(294,847)	1,039	3,550	149,325
Change in Allocation of Existing Asset Charge (no rate of return) - Appendix G					
Option 1 - Vehicle hrs for vehicles and general allocations (direct labour hours) for other assets	(87,736)	(90,668)	42	1,706	(47,600)
Option 2 - Direct Labour hrs for vehicles and general allocations (direct labour hours) for other assets	(84,529)	(81,922)		2,414	5,020
Introduction of Rate of Return in Allocation of Asset Charge - Appendix H					
Option 1 - Vehicle hrs for vehicles and general allocations (direct labour hours) for other assets	119,120	108,616	3	1,204	44,816
Option 2 - Direct Labour hrs for vehicles and general allocations (direct labour hours) for other assets	113,854	117,824		1,371	42,607
Revenue Increase to Services - Rate of Return Charge					(449,833)
Eligible Directly Charged Administrative and General Expenses Allocated to Capital (LDC - gross expenditures of $581,074 less excluded expenses of $235,614 (per Appendix L) X 31%	(107,093)	(38,963)	(22,335)	(1,136)	0
(other businesses - direct A&G expenses X capital proportion per Appendix I)					
Total - Option 1	(600,042)	(315,862)	(21,251)	5,324	(303,292)
Total - Option 2	(602,101)	(297,908)	(21,296)	6,199	(252,881)
Capital Expenses					
Change in Allocation of A&G Costs (Appendices B to F)	341,847	301,685	6,237	727	15,468
Change in Allocation of Existing Asset Charge (no rate of return) - Appendix G					
Option 1 - Vehicle hrs for vehicles and general allocations (direct labour hours) for other assets	121,418	25,486	488	292	76,571
Option 2 - Direct Labour hrs for vehicles and general allocations (direct labour hours) for other assets	124,750	27,694	321	459	5,793
Introduction of Rate of Return in Allocation of Asset Charge - Appendix H					
Option 1 - Vehicle hrs for vehicles and general allocations (direct labour hours) for other assets	141,508	27,269	278	200	6,818
Option 2 - Direct Labour hrs for vehicles and general allocations (direct labour hours) for other assets	138,803	27,872	363	261	6,878
LDC - Eligible Directly Charged Administrative and General Expenses Allocated to Capital (gross expenditures of $581,074 less excluded expenses of $235,614 (per Appendix L) X 31%	107,093	38,963	22,335	1,136	0
(other businesses - direct A&G expenses X capital proportion per Appendix I)					
Total - Option 1	711,866	393,403	29,338	2,355	98,857
Total - Option 2	712,493	396,214	29,256	2,583	28,139

APPENDIX 10

2018 Test Year Income Tax PILs Workform

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Version 1.00

Utility Name	PUC Distribution Inc.
Assigned EB Number	EB-2017-0071
Name and Title	Andrew Belsito, Rates and Regulatory Affairs Officer
Phone Number	705-759-3009
Email Address	andrew.belsito@ssmpuc.com
Date	1-May
Last COS Re-based Year	2013

Note: Drop-down lists are shaded blue; Input cells are shaded green.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Instructions

Purpose

The purpose of this workbook is to calculate the estimated Payment in Lieu of Taxes (PILs) for the Test Year. The calculation of PILs for the Test Year is on tab T0 and is based on the inputs on the other tabs.

Tab S Summary is a summary of the amounts to be transferred to the Data Input Sheet of the Revenue Requirement Workform.

Tab S1 Integrity Checks must be completed after the completion of the PILS calculation in this workbook.

Methodology

To calculate the PILs for the Test Year:

1) input the balances from the income tax return of the Historical Year in tabs H1 to H13.
2) input the balances for the Bridge Year and the Test Year.
Inputs should include:
- non-deductible expenses (Schedule 1 - B1 and T1)
- loss carryforward (Schedule 4 - B4 and T4)
- capital cost allowance (Schedule 8 - B8 and T8)
- non-deductible reserves (Schedule 13 - B13 and T13)

3) make any other adjustments and inputs required so that the PILs amount calculated for the Test Year on tab T0 is reasonable.

Other Notes

Tabs H1 to H13 relate to the Historical Year.
Tabs B1 to B13 relate to the Bridge Year.
Tabs T1 to T13 relate to the Test Year.

The amounts on tabs H1 to H13 should agree to the tax return filed with the Canada Revenue Agency. Any CRA audit adjustments or corrections should also be reflected.

It is assumed the net income before tax for the Test Year is equal to the Return on Equity. Return on Equity is calculated on tab A.

On tab "A. Data Input Sheet", input the "Rate Base" amount and "Return on Rate Base" amounts.

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Historical Year

Bridge Year

Test Year

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

No inputs required on this worksheet.

Inputs on Service Revenue Requirement Worksheet

The Service Revenue Requirement is in the 'Revenue Requirement Workform' - Tab 3.

Item	Working Paper Reference	
Adjustments required to arrive at taxable income	as below	**-2,569,412**
Test Year - Payments in Lieu of Taxes (PILs)	T0	**269,325**
Test Year - Grossed-up PILs	T0	**366,429**
Effective Federal Tax Rate	T0	**15.0%**
Effective Ontario Tax Rate	T0	**11.5%**

Calculation of Adjustments required to arrive at Taxable Income			
Regulatory Income (before income taxes)	T1	3,585,733	
Taxable Income	T1	1,016,321	
Difference	calculated	-2,569,412	as above

Income Tax/PILs Workform for 2018 Filers

Integrity Checks

The applicant must ensure the following integrity checks have been completed and confirm this is the case in the table below, or provide an explanation if this is not the case:

	Item	Utility Confirmation (Y/N)	Notes
1	The depreciation and amortization added back in the application's PILs model agree with the numbers disclosed in the rate base section of the application	Y	
2	The capital additions and deductions in the UCC/ CCA Schedule 8 agree with the rate base section for historical, bridge and test years	Y	
3	Schedule 8 of the most recent federal T2 tax return filed with the application has a closing December 31 historical year UCC that agrees with the opening (January 1) bridge year UCC. If the amounts do not agree, then the applicant must provide a reconciliation with explanations. Distributors must segregate non- distribution tax amounts on Schedule 8.	Y	
4	The CCA deductions in the application's PILs tax model for historical, bridge and test years (as applicable) agree with the numbers in the UCC schedules for the same years filed in the application	Y	
5	Loss carry-forwards, if any, from the tax returns (Schedule 4) agree with those disclosed in the application	Y	
6	A discussion is included in the application as to when the loss carry-forwards, if any, will be fully utilized	Y	
7	CCA is maximized even if there are tax loss carry-forwards	Y	
8	Accounting OPEB and pension amounts added back on Schedule 1 to reconcile accounting income to net income for tax purposes, must agree with the OM&A analysis for compensation. The amounts deducted must be reasonable when compared with the notes in the audited financial statements, FSCO reports, and the actuarial valuations.	N/A	
9	The income tax rate used to calculate the tax expense must be consistent with the utility's actual tax facts and evidence filed in the application.	Y	

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Income Tax/PILs Workform for 2018 Filers

			Test Year	Bridge Year		
Rate Base		S	**$ 99,603,703**	**$ 101,960,588**		

Return on Ratebase

			Test Year		
Deemed ShortTerm Debt %	2.29%	T	$ 2,280,925	*W = S * T*	
Deemed Long Term Debt %	4.12%	U	$ 4,103,673	*X = S * U*	
Deemed Equity %	9.00%	V	$ 8,964,333	*Y = S * V*	
Short Term Interest Rate	4.00%	Z	$ 91,237	*AC = W * Z*	
Long Term Interest	56.00%	AA	$ 2,298,057	*AD = X * AA*	
Return on Equity (Regulatory Income)	40.00%	AB	**$ 3,585,733**	*AE = Y * AB*	T1
Return on Rate Base			**$ 5,975,027**	*AF = AC + AD + AE*	

Questions that must be answered

	Historical Year	Bridge Year	Test Year
1. Does the applicant have any Investment Tax Credits (ITC)?	No	No	No
2. Does the applicant have any SRED Expenditures?	No	No	No
3. Does the applicant have any Capital Gains or Losses for tax purposes?	No	No	No
4. Does the applicant have any Capital Leases?	No	No	No
5. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	No	No	No
6. Since 1999, has the applicant acquired another regulated applicant's assets?	No	No	No
7. Did the applicant pay dividends? *If Yes, please describe what was the tax treatment in the manager's summary.*	Yes	Yes	Yes
8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes?	No	No	No

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Income Tax/PILs Workform for 2018 Filers

Tax Rates **Federal & Provincial** **As of May 16, 2016**	**Effective January 1, 2013**	**Effective January 1, 2014**	**Effective January 1, 2015**	**Effective January 1, 2016**	**Effective January 1, 2017**	**Effective January 1, 2018**
Federal income tax						
General corporate rate	38.00%	38.00%	38.00%	38.00%	38.00%	38.00%
Federal tax abatement	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%
Adjusted federal rate	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%
Rate reduction	-13.00%	-13.00%	-13.00%	-13.00%	-13.00%	-13.00%
Federal Income Tax	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Ontario income tax	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%
Combined federal and Ontario	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
Federal & Ontario Small Business						
Federal small business threshold	500,000	500,000	500,000	500,000	500,000	500,000
Ontario Small Business Threshold	500,000	500,000	500,000	500,000	500,000	500,000
Federal small business rate	11.00%	11.00%	11.00%	10.50%	10.50%	10.50%
Ontario small business rate	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%

Notes

1. The Ontario Energy Board's proxy for taxable capital is rate base.
2. Regarding the small business deduction, if applicable,
    a. If taxable capital exceeds $15 million, the small business rate will not be applicable.
    b. If taxable capital is below $10 million, the small business rate would be applicable.
    c. If taxable capital is between $10 million and $15 million, the appropriate small business rate will be calculated.

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

PILs Tax Provision - Historical Year

Note: Input the actual information from the tax returns for the historical year.

					Wires Only	
Regulatory Taxable Income				H1	$ 364,437	**A**
Combined Tax Rate and PILs	Ontario Tax Rate (Maximum 11.5%)	15.00%	**B**			
	Federal tax rate (Maximum 15%)	11.50%	**C**			
	Combined tax rate (Maximum 26.5%)				26.50%	**D = B+C**
Total Income Taxes					**$ 96,576**	**E = A * D**
Investment Tax Credits						**F**
Miscellaneous Tax Credits						**G**
Total Tax Credits					**$ -**	**H = F + G**
Corporate PILs/Income Tax Provision for Historical Year					**$ 96,576**	**I = E - H**

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Adjusted Taxable Income - Historical Year

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Historic Wires Only
Income before PILs/Taxes	A			0
Additions:				
Interest and penalties on taxes	103			0
Amortization of tangible assets	104	4,202,174		4,202,174
Amortization of intangible assets	106			0
Recapture of capital cost allowance from Schedule 8	107			0
Gain on sale of eligible capital property from Schedule 10	108			0
Income or loss for tax purposes- joint ventures or partnerships	109			0
Loss in equity of subsidiaries and affiliates	110	1,935,479		1,935,479
Loss on disposal of assets	111			0
Charitable donations	112			0
Taxable Capital Gains	113			0
Political Donations	114			0
Deferred and prepaid expenses	116			0
Scientific research expenditures deducted on financial statements	118			0
Capitalized interest	119			0
Non-deductible club dues and fees	120			0
Non-deductible meals and entertainment expense	121	3,105		3,105
Non-deductible automobile expenses	122			0
Non-deductible life insurance premiums	123			0
Non-deductible company pension plans	124			0
Tax reserves deducted in prior year	125			0
Reserves from financial statements- balance at end of year	126			0
Soft costs on construction and renovation of buildings	127			0
Book loss on joint ventures or partnerships	205			0
Capital items expensed	206			0
Debt issue expense	208			0
Development expenses claimed in current year	212			0
Financing fees deducted in books	216			0
Gain on settlement of debt	220			0
Non-deductible advertising	226			0
Non-deductible interest	227			0
Non-deductible legal and accounting fees	228			0
Recapture of SR&ED expenditures	231			0
Share issue expense	235			0
Write down of capital property	236			0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237			0
Other Additions				
Interest Expensed on Capital Leases	290			0
Realized Income from Deferred Credit Accounts	291			0
Pensions	292			0
Non-deductible penalties	293			0
	294			0
	295			0
ARO Accretion expense				0
Capital Contributions Received (ITA 12(1)(x))				0
Lease Inducements Received (ITA 12(1)(x))				0
Deferred Revenue (ITA 12(1)(a))				0
Prior Year Investment Tax Credits received				0
				0

				0
				0
				0
				0
				0
				0
				0
				0
				0
Total Additions		**6,140,758**	**0**	**6,140,758**
Deductions:				
Gain on disposal of assets per financial statements	401			0
Dividends not taxable under section 83	402			0
Capital cost allowance from Schedule 8	403	5,587,907		5,587,907
Terminal loss from Schedule 8	404			0
Cumulative eligible capital deduction from Schedule 10	405	188,414		188,414
Allowable business investment loss	406			0
Deferred and prepaid expenses	409			0
Scientific research expenses claimed in year	411			0
Tax reserves claimed in current year	413			0
Reserves from financial statements - balance at beginning of year	414			0
Contributions to deferred income plans	416			0
Book income of joint venture or partnership	305			0
Equity in income from subsidiary or affiliates	306			0
Other deductions: (Please explain in detail the nature of the item)				
Interest capitalized for accounting deducted for tax	390			0
Capital Lease Payments	391			0
Non-taxable imputed interest income on deferral and variance accounts	392			0
	393			0
	394			0
ARO Payments - Deductible for Tax when Paid				0
ITA 13(7.4) Election - Capital Contributions Received				0
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds				0
Deferred Revenue - ITA 20(1)(m) reserve				0
Principal portion of lease payments				0
Lease Inducement Book Amortization credit to income				0
Financing fees for tax ITA 20(1)(e) and (e.1)				0
				0
				0
				0
				0
				0
				0
				0
Total Deductions		**5,776,321**	**0**	**5,776,321**
Net Income for Tax Purposes		**364,437**	**0**	**364,437**
Charitable donations from Schedule 2	311			0
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320			0
Non-capital losses of preceding taxation years from Schedule 4	331			0
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332			0
Limited partnership losses of preceding taxation years from Schedule 4	335			0
TAXABLE INCOME		**364,437**	**0**	**364,437**

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Schedule 7-1 Loss Carry Forward - Historical

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance	
Actual Historical	-203,910		-203,910	B4

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance	
Actual Historical			0	B4

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Income Tax/PILs Workform for 2018 Filers

Schedule 8 - Historical Year

Class	Class Description	UCC End of Year Historical per tax returns	Less: Non-Distribution Portion	UCC Regulated Historical Year
1	Distribution System - post 1987	###########		############
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ 140,815.00		$ 140,815.00
2	Distribution System - pre 1988			$ -
8	General Office/Stores Equip	$1,818,822.00		$ 1,818,822.00
10	Computer Hardware/ Vehicles			$ -
10.1	Certain Automobiles			$ -
12	Computer Software			$ -
13_1	Lease # 1			$ -
13_2	Lease #2			$ -
13_3	Lease # 3			$ -
13_4	Lease # 4			$ -
14	Franchise			$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs			$ -
42	Fibre Optic Cable			$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment			$ -
43.2	Certain Clean Energy Generation Equipment			$ -
45	Computers & Systems Software acq'd post Mar 22/04			$ -
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)			$ -
47	Distribution System - post February 2005	###########		############
50	Data Network Infrastructure Equipment - post Mar 2007			$ -
52	Computer Hardware and system software			$ -
95	CWIP			$ -
				$ -
				$ -
				$ -
				$ -
				$ -
				$ -
				$ -
				$ -
				$ -
				0
	SUB-TOTAL - UCC	86,613,148	0	86,613,148

Schedule 10 CEC - Historical Year

Cumulative Eligible Capital				**2,691,625**
Additions				
Cost of Eligible Capital Property Acquired during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**2,691,625**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**2,691,625**
Current Year Deduction		**2,691,625**	**x 7% =**	**188,414**
Cumulative Eligible Capital - Closing Balance				**#########**

Ontario Energy Board

Income Tax/PILs Workform for 2

Schedule 13 Tax Reserves - Historical

Continuity of Reserves

Description	Historical Balance as per tax returns	Non-Distribution Eliminations	Utility Only
Capital Gains Reserves ss.40(1)			0
Tax Reserves Not Deducted for accounting purposes			
Reserve for doubtful accounts ss. 20(1)(l)			0
Reserve for goods and services not delivered ss. 20(1)(m)			0
Reserve for unpaid amounts ss. 20(1)(n)			0
Debt & Share Issue Expenses ss. 20(1)(e)			0
Other tax reserves			0
			0
			0
			0
			0
			0
Total	0	0	**0**
Financial Statement Reserves (not deductible for Tax Purposes)			
General Reserve for Inventory Obsolescence (non-specific)			0
General reserve for bad debts			0
Accrued Employee Future Benefits:			0
- Medical and Life Insurance			0
-Short & Long-term Disability			0
-Accmulated Sick Leave			0
- Termination Cost			0
- Other Post-Employment Benefits			0
Provision for Environmental Costs			0
Restructuring Costs			0
Accrued Contingent Litigation Costs			0
Accrued Self-Insurance Costs			0
Other Contingent Liabilities			0
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0
Other			0
			0
			0
Total	0	0	**0**

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Income Tax/PILs Workform for 2018 Filers

PILS Tax Provision - Bridge Year

	Reference	Wires Only	
Regulatory Taxable Income	B1	-$ 840,365	**A**

	Tax Rate	Small Business Rate (If Applicable)	Taxes Payable	Effective Tax Rate	
Ontario (Max 11.5%)	11.5%	11.5%	-$ 96,642	11.5%	**B**
Federal (Max 15%)	15.0%	15.0%	-$ 126,055	15.0%	**C**

Combined effective tax rate (Max 26.5%)	26.50%	**D = B + C**
Total Income Taxes	$ -	**E = A * D**
Investment Tax Credits		**F**
Miscellaneous Tax Credits		**G**
Total Tax Credits	$ -	**H = F + G**
Corporate PILs/Income Tax Provision for Bridge Year	$ -	**I = E - H**

Note:

1. This is for the derivation of Bridge year PILs income tax expense and should not be used for Test year revenue requirement calculations.

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Adjusted Taxable Income - Bridge Year

	T2S1 line #	Working Paper Reference	Total for Regulated Utility
Income before PILs/Taxes	A		1,242,551

Additions:			
Interest and penalties on taxes	103		
Amortization of tangible assets	104		3,663,582
Amortization of intangible assets	106		
Recapture of capital cost allowance from Schedule 8	107		
Gain on sale of eligible capital property from Schedule 10	108		
Income or loss for tax purposes- joint ventures or partnerships	109		
Loss in equity of subsidiaries and affiliates	110		
Loss on disposal of assets	111		
Charitable donations	112		
Taxable Capital Gains	113		
Political Donations	114		
Deferred and prepaid expenses	116		
Scientific research expenditures deducted on financial statements	118		
Capitalized interest	119		
Non-deductible club dues and fees	120		
Non-deductible meals and entertainment expense	121		
Non-deductible automobile expenses	122		
Non-deductible life insurance premiums	123		
Non-deductible company pension plans	124		
Tax reserves deducted in prior year	125	B13	0
Reserves from financial statements- balance at end of year	126	B13	0
Soft costs on construction and renovation of buildings	127		
Book loss on joint ventures or partnerships	205		
Capital items expensed	206		
Debt issue expense	208		
Development expenses claimed in current year	212		
Financing fees deducted in books	216		
Gain on settlement of debt	220		
Non-deductible advertising	226		
Non-deductible interest	227		
Non-deductible legal and accounting fees	228		
Recapture of SR&ED expenditures	231		
Share issue expense	235		
Write down of capital property	236		
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237		
Other Additions			
Interest Expensed on Capital Leases	290		
Realized Income from Deferred Credit Accounts	291		
Pensions	292		
Non-deductible penalties	293		
	294		
	295		
ARO Accretion expense			
Capital Contributions Received (ITA 12(1)(x))			
Lease Inducements Received (ITA 12(1)(x))			
Deferred Revenue (ITA 12(1)(a))			
Prior Year Investment Tax Credits received			

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Adjusted Taxable Income - Bridge Year

Total Additions			**3,663,582**
Deductions:			
Gain on disposal of assets per financial statements	401		
Dividends not taxable under section 83	402		
Capital cost allowance from Schedule 8	403	B8	5,746,499
Terminal loss from Schedule 8	404		
Allowable business investment loss	406		
Deferred and prepaid expenses	409		
Scientific research expenses claimed in year	411		
Tax reserves claimed in current year	413	B13	0
Reserves from financial statements - balance at beginning of year	414	B13	0
Contributions to deferred income plans	416		
Book income of joint venture or partnership	305		
Equity in income from subsidiary or affiliates	306		
Other deductions: (Please explain in detail the nature of the item)			
Interest capitalized for accounting deducted for tax	390		
Capital Lease Payments	391		
Non-taxable imputed interest income on deferral and variance accounts	392		
	393		
	394		
ARO Payments - Deductible for Tax when Paid			
ITA 13(7.4) Election - Capital Contributions Received			
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds			
Deferred Revenue - ITA 20(1)(m) reserve			
Principal portion of lease payments			
Lease Inducement Book Amortization credit to income			
Financing fees for tax ITA 20(1)(e) and (e.1)			
Total Deductions		calculated	**5,746,499**
Net Income for Tax Purposes		calculated	**-840,365**
Charitable donations from Schedule 2	311		
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320		
Non-capital losses of preceding taxation years from Schedule 4	331	B4	0
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332	B4	0
Limited partnership losses of preceding taxation years from Schedule 4	335		
TAXABLE INCOME		calculated	**-840,365**

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Corporation Loss Continuity and Application

Schedule 4 Loss Carry Forward - Bridge Year

Non-Capital Loss Carry Forward Deduction		**Total**	
Actual Historical	H4	-203,910	
Amount to be used in Bridge Year	B1	0	
Loss Carry Forward Generated in Bridge Year (if any)	B1	840,365	
Other Adjustments			
Balance available for use post Bridge Year	calculated	636,455	T4

Net Capital Loss Carry Forward Deduction		**Total**	
Actual Historical	H4	0	
Amount to be used in Bridge Year			
Loss Carry Forward Generated in Bridge Year (if any)	B1		
Other Adjustments			
Balance available for use post Bridge Year	calculated	0	T4

Schedule 8 CCA - Bridge Year

Class	Class Description	Working Paper Reference	UCC Regulated Historical Year	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Bridge Year CCA		UCC End of Bridge Year
1	Distribution System - post 1987	H8	$ 44,009,981.00			$ 44,009,981	$ -	$ 44,009,981	4%	$ 1,760,399		$ 42,249,582
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	H8	$ 140,815.00			$ 140,815	$ -	$ 140,815	6%	$ 8,449		$ 132,366
2	Distribution System - pre 1988	H8				$ -	$ -	$ -	6%	$ -		$ -
8	General Office/Stores Equip	H8	$ 1,818,822.00			$ 1,818,822	$ -	$ 1,818,822	20%	$ 363,764		$ 1,455,058
10	Computer Hardware/ Vehicles	H8				$ -	$ -	$ -	30%	$ -		$ -
10.1	Certain Automobiles	H8				$ -	$ -	$ -	30%	$ -		$ -
12	Computer Software	H8				$ -	$ -	$ -	100%	$ -		$ -
13 1	Lease # 1	H8				$ -	$ -	$ -		$ -		$ -
13 2	Lease #2	H8				$ -	$ -	$ -		$ -		$ -
13 3	Lease # 3	H8				$ -	$ -	$ -		$ -		$ -
13 4	Lease # 4	H8				$ -	$ -	$ -		$ -		$ -
14	Franchise	H8				$ -	$ -	$ -		$ -		$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	H8				$ -	$ -	$ -	8%	$ -		$ -
42	Fibre Optic Cable	H8				$ -	$ -	$ -	12%	$ -		$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment	H8				$ -	$ -	$ -	30%	$ -		$ -
43.2	Certain Clean Energy Generation Equipment	H8				$ -	$ -	$ -	50%	$ -		$ -
45	Computers & Systems Software acq'd post Mar 22/04	H8				$ -	$ -	$ -	45%	$ -		$ -
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	H8				$ -	$ -	$ -	30%	$ -		$ -
47	Distribution System - post February 2005	H8	$ 40,643,530.00	$ 4,679,475		$ 45,323,005	$ 2,339,738	$ 42,983,268	8%	$ 3,438,661		$ 41,884,344
50	Data Network Infrastructure Equipment - post Mar 2007	H8				$ -	$ -	$ -	55%	$ -		$ -
52	Computer Hardware and system software	H8				$ -	$ -	$ -	100%	$ -		$ -
95	CWIP	H8				$ -	$ -	$ -	0%	$ -		$ -
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)[1]	H10	$ 2,503,211.25			$ 2,503,211	$ -	$ 2,503,211	7%	$ 175,225		$ 2,327,986
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)[1]		$ -			$ -	$ -	$ -	5%	$ -		$ -
						$ -	$ -	$ -		$ -		$ -
						$ -	$ -	$ -		$ -		$ -
						$ -	$ -	$ -		$ -		$ -
						$ -	$ -	$ -		$ -		$ -
						$ -	$ -	$ -		$ -		$ -
						$ -	$ -	$ -		$ -		$ -
						$ -	$ -	$ -		$ -		$ -
						$ -	$ -	$ -		$ -		$ -
	TOTAL		$ 89,116,359	$ 4,679,475	$ -	$ 93,795,834	$ 2,339,738	$ 91,456,097		$ 5,746,499	B1	$ 88,049,336

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Schedule 13 Tax Reserves - Bridge Year

Continuity of Reserves

						Bridge Year Adjustments					
Description	Reference	Historical Utility Only	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance		Additions	Disposals	Balance for Bridge Year		Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	H13	0		0				0	T13	0	
Tax Reserves Not Deducted for accounting purposes											
Reserve for doubtful accounts ss. 20(1)(l)	H13	0		0				0	T13	0	
Reserve for goods and services not delivered ss. 20(1)(m)	H13	0		0				0	T13	0	
Reserve for unpaid amounts ss. 20(1)(n)	H13	0		0				0	T13	0	
Debt & Share Issue Expenses ss. 20(1)(e)	H13	0		0				0	T13	0	
Other tax reserves	H13	0		0				0	T13	0	
		0		0				0		0	
		0		0				0		0	
Total		0	0	0	B1	0	0	0	B1	0	0
Financial Statement Reserves (not deductible for Tax Purposes)											
General Reserve for Inventory Obsolescence (non-specific)	H13	0		0				0	T13	0	
General reserve for bad debts	H13	0		0				0	T13	0	
Accrued Employee Future Benefits:	H13	0		0				0	T13	0	
- Medical and Life Insurance	H13	0		0				0	T13	0	
-Short & Long-term Disability	H13	0		0				0	T13	0	
-Accmulated Sick Leave	H13	0		0				0	T13	0	
- Termination Cost	H13	0		0				0	T13	0	
- Other Post-Employment Benefits	H13	0		0				0	T13	0	
Provision for Environmental Costs	H13	0		0				0	T13	0	
Restructuring Costs	H13	0		0				0	T13	0	
Accrued Contingent Litigation Costs	H13	0		0				0	T13	0	
Accrued Self-Insurance Costs	H13	0		0				0	T13	0	
Other Contingent Liabilities	H13	0		0				0	T13	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	H13	0		0				0	T13	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	H13	0		0				0	T13	0	
Other	H13	0		0				0	T13	0	
		0		0				0		0	
		0		0				0		0	
Total		0	0	0	B1	0	0	0	B1	0	0

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

PILs Tax Provision - Test Year

		Wires Only	
Regulatory Taxable Income	T1	$ 1,016,321	**A**

	Tax Rate	Small Business Rate (If Applicable)	Taxes Payable	Effective Tax Rate	
Ontario (Max 11.5%)	11.5%	11.5%	$ 116,877	11.5%	**B**
Federal (Max 15%)	15.0%	15.0%	$ 152,448	15.0%	**C**

Combined effective tax rate (Max 26.5%)			26.50%	**D = B + C**	
Total Income Taxes			**$ 269,325**	**E = A * D**	
Investment Tax Credits				**F**	
Miscellaneous Tax Credits				**G**	
Total Tax Credits			**$ -**	**H = F + G**	
Corporate PILs/Income Tax Provision for Test Year			**$ 269,325**	**I = E - H**	S. Su
Corporate PILs/Income Tax Provision Gross Up [1]	73.50%	**J = 1-D**	**$ 97,104**	**K = I/J-I**	
Income Tax (grossed-up)			**$ 366,429**	**L = K + I**	S. Su

Note:

1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Taxable Income - Test Year

	T2 S1 line #	Working Paper Reference	Test Year Taxable Income
Net Income Before Taxes		A.	3,585,733
Additions:			
Interest and penalties on taxes	103		
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104		3,783,956
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106		
Recapture of capital cost allowance from Schedule 8	107		
Gain on sale of eligible capital property from Schedule 10	108		
Income or loss for tax purposes- joint ventures or partnerships	109		
Loss in equity of subsidiaries and affiliates	110		
Loss on disposal of assets	111		
Charitable donations	112		
Taxable Capital Gains	113		
Political Donations	114		
Deferred and prepaid expenses	116		
Scientific research expenditures deducted on financial statements	118		
Capitalized interest	119		
Non-deductible club dues and fees	120		
Non-deductible meals and entertainment expense	121		
Non-deductible automobile expenses	122		
Non-deductible life insurance premiums	123		
Non-deductible company pension plans	124		
Tax reserves beginning of year	125	T13	0
Reserves from financial statements- balance at end of year	126	T13	0
Soft costs on construction and renovation of buildings	127		
Book loss on joint ventures or partnerships	205		
Capital items expensed	206		
Debt issue expense	208		
Development expenses claimed in current year	212		
Financing fees deducted in books	216		
Gain on settlement of debt	220		
Non-deductible advertising	226		
Non-deductible interest	227		
Non-deductible legal and accounting fees	228		
Recapture of SR&ED expenditures	231		
Share issue expense	235		
Write down of capital property	236		
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237		
Other Additions: (please explain in detail the nature of the item)			
Interest Expensed on Capital Leases	290		
Realized Income from Deferred Credit Accounts	291		
Pensions	292		
Non-deductible penalties	293		
	294		
	295		
	296		
	297		
ARO Accretion expense			
Capital Contributions Received (ITA 12(1)(x))			
Lease Inducements Received (ITA 12(1)(x))			
Deferred Revenue (ITA 12(1)(a))			
Prior Year Investment Tax Credits received			

Total Additions			**3,783,956**	
Deductions:				
Gain on disposal of assets per financial statements	401			
Dividends not taxable under section 83	402			
Capital cost allowance from Schedule 8	403	T8	5,716,913	
Terminal loss from Schedule 8	404			
Allowable business investment loss	406			
Deferred and prepaid expenses	409			
Scientific research expenses claimed in year	411			
Tax reserves end of year	413	T13	0	
Reserves from financial statements - balance at beginning of year	414	T13	0	
Contributions to deferred income plans	416			
Book income of joint venture or partnership	305			
Equity in income from subsidiary or affiliates	306			
Other deductions: (Please explain in detail the nature of the item)				
Interest capitalized for accounting deducted for tax	390			
Capital Lease Payments	391			
Non-taxable imputed interest income on deferral and variance accounts	392			
	393			
	394			
	395			
	396			
	397			
ARO Payments - Deductible for Tax when Paid				
ITA 13(7.4) Election - Capital Contributions Received				
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds				
Deferred Revenue - ITA 20(1)(m) reserve				
Principal portion of lease payments				
Lease Inducement Book Amortization credit to income				
Financing fees for tax ITA 20(1)(e) and (e.1)				
Total Deductions		calculated	**5,716,913**	
NET INCOME FOR TAX PURPOSES		calculated	**1,652,776**	
Charitable donations	311			
Taxable dividends received under section 112 or 113	320			
Non-capital losses of preceding taxation years from Schedule 7-1	331	T4	636,455	
Net-capital losses of preceding taxation years (Please show calculation)	332	T4	0	
Limited partnership losses of preceding taxation years from Schedule 4	335			
REGULATORY TAXABLE INCOME		calculated	**1,016,321**	T0

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Schedule 7-1 Loss Carry Forward - Test Year

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	**Working Paper Reference**	**Total**	**Non-Distribution Portion**	**Utility Balance**
Actual/Estimated Bridge Year Carried Forward	B4	636,455		636,455
Amount to be used in Test Year and Price Cap Years	T1	636,455		636,455
Number of years loss until next cost of service (i.e. years the loss is to be spread over)				
Amount to be used in Test Year	calculated	636,455		636,455
Loss Carry Forward Generated in Test Year (if any)	T1	0		0
Other Adjustments				0
Balance available for use in Future Years	calculated	0		0

Net Capital Loss Carry Forward Deduction		**Total**	**Non-Distribution Portion**	**Utility Balance**
Actual/Estimated Bridge Year Carried Forward	B4	0		0
Amount to be used in Test Year and Price Cap Years				0
Number of years loss until next cost of service (i.e. years the loss is to be spread over)				
Amount to be used in Test Year	T1	0		0
Loss Carry Forward Generated in Test Year (if any)				0
Other Adjustments				0
Balance available for use in Future Years		0		0

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Schedule 8 CCA - Test Year

Class	Class Description	Working Paper Reference	UCC Test Year Opening Balance	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA		UCC End of Test Year
1	**Distribution System - post 1987**	B8	**$ 42,249,582**			$ 42,249,582	$ -	$ 42,249,582	**4%**	$ 1,689,983		$ 40,559,598
1 Enhanced	**Non-residential Buildings Reg. 1100(1)(a.1) election**	B8	**$ 132,366**			$ 132,366	$ -	$ 132,366	**6%**	$ 7,942		$ 124,424
2	**Distribution System - pre 1988**	B8	**$ -**			$ -	$ -	$ -	**6%**	$ -		$ -
8	**General Office/Stores Equip**	B8	**$ 1,455,058**			$ 1,455,058	$ -	$ 1,455,058	**20%**	$ 291,012		$ 1,164,046
10	**Computer Hardware/ Vehicles**	B8	**$ -**			$ -	$ -	$ -	**30%**	$ -		$ -
10.1	**Certain Automobiles**	B8	**$ -**			$ -	$ -	$ -	**30%**	$ -		$ -
12	**Computer Software**	B8	**$ -**			$ -	$ -	$ -	**100%**	$ -		$ -
13 1	**Lease # 1**	B8	**$ -**			$ -	$ -	$ -		$ -		$ -
13 2	**Lease #2**	B8	**$ -**			$ -	$ -	$ -		$ -		$ -
13 3	**Lease # 3**	B8	**$ -**			$ -	$ -	$ -		$ -		$ -
13 4	**Lease # 4**	B8	**$ -**			$ -	$ -	$ -		$ -		$ -
14	**Franchise**	B8	**$ -**			$ -	$ -	$ -		$ -		$ -
17	**New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than**	B8	**$ -**			$ -	$ -	$ -	**8%**	$ -		$ -
42	**Fibre Optic Cable**	B8	**$ -**			$ -	$ -	$ -	**12%**	$ -		$ -
43.1	**Certain Energy-Efficient Electrical Generating Equipment**	B8	**$ -**			$ -	$ -	$ -	**30%**	$ -		$ -
43.2	**Certain Clean Energy Generation Equipment**	B8	**$ -**			$ -	$ -	$ -	**50%**	$ -		$ -
45	**Computers & Systems Software acq'd post Mar 22/04**	B8	**$ -**			$ -	$ -	$ -	**45%**	$ -		$ -
46	**Data Network Infrastructure Equipment (acq'd post Mar 22/04)**	B8	**$ -**			$ -	$ -	$ -	**30%**	$ -		$ -
47	**Distribution System - post February 2005**	B8	**$ 41,884,344**	5,356,734		$ 47,241,078	$ 2,678,367	$ 44,562,711	**8%**	$ 3,565,017		$ 43,676,061
50	**Data Network Infrastructure Equipment - post Mar 2007**	B8	**$ -**			$ -	$ -	$ -	**55%**	$ -		$ -
52	**Computer Hardware and system software**	B8	**$ -**			$ -	$ -	$ -	**100%**	$ -		$ -
95	**CWIP**	B8	**$ -**			$ -	$ -	$ -	**0%**	$ -		$ -
14.1	**Eligible Capital Property (acq'd pre Jan 1, 2017)1**	B8	**$ 2,327,986**			$ 2,327,986	$ -	$ 2,327,986	**7%**	$ 162,959		$ 2,165,027
14.1	**Eligible Capital Property (acq'd post Jan 1, 2017)1**	B8	**$ -**			$ -	$ -	$ -	**5%**	$ -		$ -
			$ -			$ -	$ -	$ -	**0%**	$ -		$ -
			$ -			$ -	$ -	$ -	**0%**	$ -		$ -
			$ -			$ -	$ -	$ -	**0%**	$ -		$ -
			$ -			$ -	$ -	$ -	**0%**	$ -		$ -
			$ -			$ -	$ -	$ -	**0%**	$ -		$ -
			$ -			$ -	$ -	$ -	**0%**	$ -		$ -
			$ -			$ -	$ -	$ -	**0%**	$ -		$ -
			$ -			$ -	$ -	$ -	**0%**	$ -		$ -
	TOTAL		**$ 88,049,336**	**$ 5,356,734**	**$ -**	**$ 93,406,070**	**$ 2,678,367**	**$ 90,727,703**		**$ 5,716,913**	T1	**$ 87,689,157**

1. New CCA class 14.1 effective January 1, 2017. The class includes property that was eligible capital property immediately before January 1, 2017. For tax years that end prior to 2027, transitional rules apply to class 14.1 that were acquired before January 1, 2017

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Schedule 13 Tax Reserves - Test Year

Continuity of Reserves

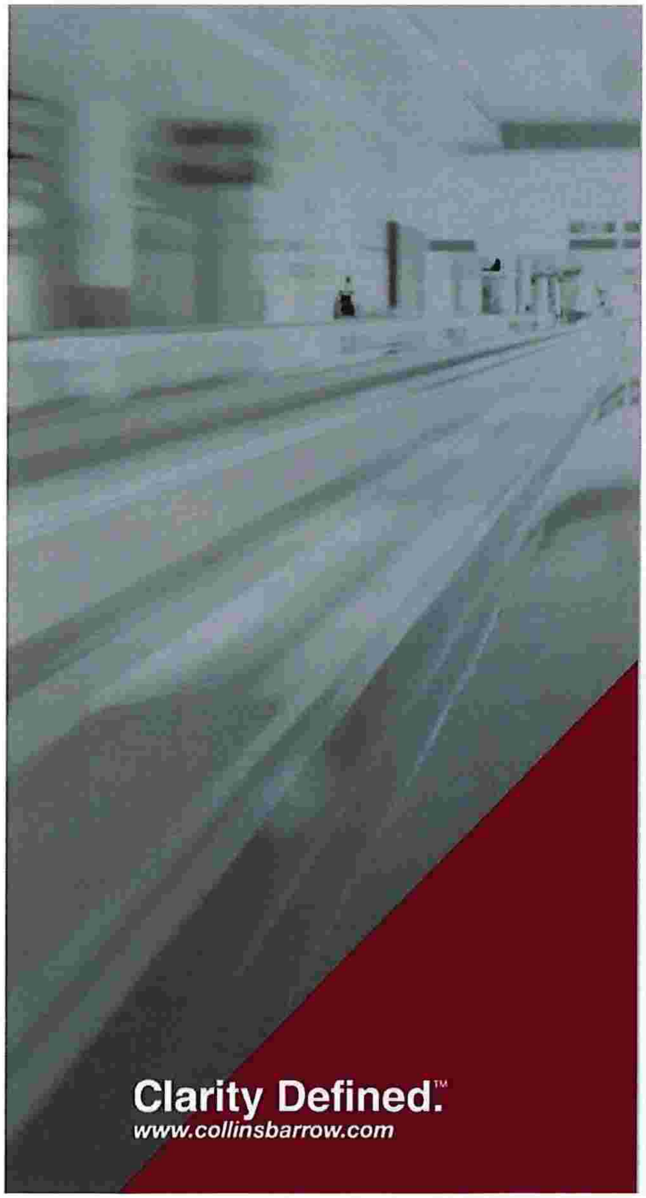
Description	Working Paper Reference	Bridge Year	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance		Test Year Adjustments		Balance for Test Year		Change During the Year	Disallowed Expenses
						Additions	Disposals				
Capital Gains Reserves ss.40(1)	B13	0		0				0		0	
Tax Reserves Not Deducted for accounting purposes											
Reserve for doubtful accounts ss. 20(1)(l)	B13	0		0		0	0	0		0	
Reserve for goods and services not delivered ss. 20(1)(m)	B13	0		0				0		0	
Reserve for unpaid amounts ss. 20(1)(n)	B13	0		0				0		0	
Debt & Share Issue Expenses ss. 20(1)(e)	B13	0		0				0		0	
Other tax reserves	B13	0		0				0		0	
		0		0				0		0	
		0		0				0		0	
Total		**0**	**0**	**0**	T1	**0**	**0**	**0**	T1	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)											
General Reserve for Inventory Obsolescence (non-specific)	B13	0		0				0		0	
General reserve for bad debts	B13	0		0				0		0	
Accrued Employee Future Benefits:	B13	0		0				0		0	
- Medical and Life Insurance	B13	0		0				0		0	
-Short & Long-term Disability	B13	0		0				0		0	
-Accmulated Sick Leave	B13	0		0				0		0	
- Termination Cost	B13	0		0				0		0	
- Other Post-Employment Benefits	B13	0		0				0		0	
Provision for Environmental Costs	B13	0		0				0		0	
Restructuring Costs	B13	0		0				0		0	
Accrued Contingent Litigation Costs	B13	0		0				0		0	
Accrued Self-Insurance Costs	B13	0		0				0		0	
Other Contingent Liabilities	B13	0		0				0		0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	B13	0		0				0		0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	B13	0		0				0		0	
Other	B13	0		0				0		0	
		0		0				0		0	
		0		0				0		0	
Total		**0**	**0**	**0**	T1	**0**	**0**	**0**	T1	**0**	**0**

APPENDIX 11

2015 Actuarial Valuation for PUC Services Inc.

2017 Actuarial Valuation for PUC Services Inc

COLLINS BARROW TORONTO
ACTUARIAL SERVICES



SAULT STE. MARIE PUC SERVICES INC.

Report on the Actuarial Valuation of Post-Retirement Non-Pension Benefits

As at December 31, 2015

March 8, 2016 – Draft

Clarity Defined.™
www.collinsbarrow.com

Collins Barrow

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EXECUTIVE SUMMARY

PURPOSE

Collins Barrow Toronto Actuarial Services Inc. was engaged by Sault Ste. Marie PUC Services Inc. (the "Corporation") to perform an actuarial valuation of the post-retirement non-pension benefits sponsored by the Corporation and to determine the accounting results for those benefits for the fiscal period ending December 31, 2015. The nature of these benefits is defined benefit.

This report is prepared in accordance with the International Financial Reporting Standards (the "IFRS") guidelines for post-retirement non-pension benefits as outlined in the amendments to the International Accounting Standard 19 – Employee Benefits ("IAS 19") issued in June 2011. The Corporation began reporting on the basis of IFRS for the fiscal year beginning January 1, 2015. Prior to this date, the valuation of the Corporation's post-retirement non-pension benefits was prepared in accordance with the Canadian Institute of Chartered Accountants ("CICA") guidelines outlined in Employee Future Benefits, Section 3461 of the CICA Handbook-Accounting ("CICA 3461").

The most recent full valuation was prepared as at January 1, 2013 based on the then appropriate assumptions and in accordance with CICA 3461.

The purpose of this valuation is threefold:

i) To determine the Corporation's liabilities in respect of post-retirement non-pension benefits at December 31, 2015;

ii) To determine the expense to be recognized in the income statement for fiscal year 2016; and

iii) To provide all other pertinent information necessary for compliance with IAS 19.

The intended users of this report include the Corporation and its auditors. This report is not intended for use by the plan beneficiaries or for use in determining any funding of the benefit obligations.

SUMMARY OF KEY RESULTS

The key results of this actuarial valuation as at December 31, 2015 with comparative results from the previous valuation as at January 1, 2013 are shown below, in thousands of dollars:

	January 1, 2013 (CICA 3461)	**December 31, 2015 (IAS 19)**
Present Value of Defined Benefit Obligation (PV DBO)		
a) People in Receipt of Benefits	365	337
b) Fully Eligible Actives	452	647
c) Not Fully Eligible Actives	856	863
Total PV DBO	**1,673**	**1,847**

	CY 2013 (CICA 3461)	**CY 2016 (IAS 19)**
Current Service Cost	89	104
Interest Cost	67	73
Recognition of Past Service Cost	16	n/a
Recognition of Actuarial (Gains)/Losses	(98)	n/a
Defined Benefit Cost Recognized in Income Statement	**74**	**177**

ACTUARIAL CERTIFICATION

An actuarial valuation has been performed on the post-retirement non-pension benefit plans sponsored by Sault Ste. Marie PUC Services Inc. (the "Corporation") as at December 31, 2015, for the purposes described in this report.

In accordance with the Canadian Institute of Actuaries Consolidated Standards of Practice General Standards, we hereby certify that, in our opinion, for the purposes stated in the Executive Summary:

1. The data on which the valuation is based is sufficient and reliable;
2. The assumptions employed, as outlined in this report, have been selected by the Corporation as management's best estimate assumptions (no provision for adverse deviations) and we express no opinion on them;
3. All known legal and constructive obligations with respect to the post-retirement non-pension benefits sponsored by and identified by the Corporation are included in the calculations; and
4. This report has been prepared, and our opinions given, in accordance with accepted actuarial practice in Canada.

We are not aware of any subsequent events after December 31, 2015 that would have a significant effect on our valuation.

The latest date on which the next actuarial valuation should be performed is December 31, 2018. If any supplemental advice or explanation is required, please advise the undersigned.

Respectfully submitted,

COLLINS BARROW TORONTO ACTUARIAL SERVICES INC.

Stanley Caravaggio, FSA FCIA
Senior Manager

Jamie Wong
Actuarial Analyst

Toronto, Ontario

March 8, 2016

SECTION A— VALUATION RESULTS

Table A - 1 shows the key valuation results for the prior valuation and the current valuation.

Table A - 2 shows the sensitivity of the valuation results to certain changes in assumptions. We have shown a change to the assumed retirement age from age 59 to 57, an increase/decrease in the health claims cost trend rates by 1% per annum, and an increase/decrease in the discount rate by 1% per annum.

Table A - 3 presents the reconciliation of changes in the present value of defined benefit obligation at December 31, 2015.

VALUATION RESULTS

Table A.1—Valuation Results
(in thousands of dollars)

	January 1, 2013 (CICA 3461)	December 31, 2015 (IAS 19)
Present Value of Defined Benefit Obligation (PV DBO)		
a) People in Receipt of Benefits	365	337
b) Fully Eligible Actives	452	647
c) Not Fully Eligible Actives	856	863
Total PV DBO	**1,673**	**1,847**

	CY 2013 (CICA 3461)	CY 2016 (IAS 19)
Current Service Cost	89	104
Interest Cost	67	73
Recognition of Past Service Cost	16	n/a
Recognition of Actuarial (Gains)/Losses	(98)	n/a
Defined Benefit Cost Recognized in Income Statement	**74**	**177**
Actuarial (Gains)/Losses	n/a	-
Defined Benefit Cost Recognized in Other Comprehensive Income	**n/a**	**-**
Total Defined Benefit Cost	**74**	**177**
Expected Benefit Payments	**56**	**121**

The benefit payments for CY 2016 are based on the estimated payments to be made for those expected to be eligible for benefits.

SENSITIVITY ANALYSIS

Table A.2—Sensitivity Analysis (in thousands of dollars)

	PV DBO at December 31, 2015				CY 2016	
	People in Receipt of Benefits	**Fully Eligible Actives**	**Not Fully Eligible Actives**	**Total PV DBO**	**Current Service Cost**	**Interest Cost**
Valuation Results	337	647	863	**1,847**	104	73
Retirement Age 57	337	743	1,139	**2,219**	137	88
Cost Trends +1%	343	669	1,005	**2,017**	124	80
Cost Trends -1%	332	626	744	**1,702**	87	67
Discount Rate 3.1%	358	684	1,024	**2,066**	126	62
Discount Rate 5.1%	319	615	733	**1,667**	87	82

RECONCILIATION OF CHANGES IN THE DEFINED BENEFIT OBLIGATION

Table A.3—Reconciliation of Changes in the Present Value of Defined Benefit Obligation (in thousands of dollars)

PV DBO at December 31, 2014 (IAS 19)	1,804
2015 Current Service Cost	94
2015 Benefit Payments	(60)
2015 Interest Cost	69
Expected PV DBO at December 31, 2015	**1,907**
Actuarial (Gain)/Loss at December 31, 2015	(60)
PV DBO at December 31, 2015	**1,847**

The decrease indicated above of $60,000 in the PV DBO from the expected PV DBO at December 31, 2015 is due to the re-measurement of the liability; a breakdown of the changes is as follows:

- A change in the claims cost trend rate assumption (an increase of approximately $35,000)
- A change in the mortality improvement assumption (an increase of approximately $7,000)
- A change in the discount rate assumption (an decrease of approximately $40,000)
- A change in the health benefit cost level assumptions (a decrease of approximately $75,000)
- Deviations from the expected demographic changes of the valued groups due to factors such as the difference between expected and actual group experience, changes in coverage type, changes in employee status, and new hires (an increase of approximately $13,000)

Pursuant to IAS 19, the re-measurement of the PV DBO at December 31, 2015 based on the changes in the assumptions and experience is recognized as an adjustment to other comprehensive income.

SECTION B— PLAN PARTICIPANTS

Table B – 1 sets out the summary information with respect to the plan participants valued in the report, along with comparisons to the participants in the previous valuation with data as of January 1, 2013.

Table B – 2 reconciles the number of participants in the last valuation to the number of participants in the current valuation.

PARTICIPANT DATA

Table B.1—Participant Data

Membership data as at December 31, 2015 was received from the Corporation via e-mail and included information such as name, sex, age, date of hire, current salary, benefit amounts and other applicable details for all active employees and people in receipt of benefits.

We have reviewed the data and compared it to the data used in the prior valuation for consistency and reliability for use in this valuation. The main tests of sufficiency and reliability that were conducted on the membership data are as follows:

- Date of hire prior to date of birth;
- Ages under 18 or over 100;
- Abnormal levels of benefits and/or premiums; and
- Duplicate records

In addition, the following tests were performed:

- A reconciliation of statuses from the prior valuation to the current valuation;
- A review of the consistency of individual data items and statistical summaries between the current and prior valuations; and
- A review of the reasonableness of changes in such information since the prior valuation.

Active Employees

	January 1, 2013			December 31, 2015		
	Male	Female	Total	Male	Female	Total
Number of Employees	122	45	167	140	47	187
Avg. Length of Service	12.5	12.3	12.4	12.2	12.2	12.2

Count as of December 31, 2015

	Active Lives - Not Fully Eligible			Active Lives - Fully Eligible		
Age Band	Male	Female	Total	Male	Female	Total
Less than 30	15	3	18	-	-	-
30 - 35	26	8	34	-	-	-
36 - 40	21	8	29	-	-	-
41 - 45	16	5	21	-	-	-
46 - 50	10	6	16	-	-	-
51 - 55	16	6	22	6	2	8
56 - 60	-	-	-	21	5	26
61 - 65	-	-	-	7	4	11
66 - 70	-	-	-	2	-	2
71 - 75	-	-	-	-	-	-
Greater than 75	-	-	-	-	-	-
Total	**104**	**36**	**140**	**36**	**11**	**47**

Average Service as of December 31, 2015

	Active Lives - Not Fully Eligible			Active Lives - Fully Eligible		
Age Band	Male	Female	Total	Male	Female	Total
Less than 30	3.1	3.3	3.2	-	-	-
30 - 35	5.8	5.7	5.8	-	-	-
36 - 40	7.7	8.2	7.8	-	-	-
41 - 45	8.7	9.6	8.9	-	-	-
46 - 50	11.1	14.5	12.4	-	-	-
51 - 55	19.3	16.0	18.4	23.0	14.1	20.8
56 - 60	-	-	-	22.8	23.8	23.0
61 - 65	-	-	-	19.2	18.5	18.9
66 - 70	-	-	-	16.2	-	16.2
71 - 75	-	-	-	-	-	-
Greater than 75	-	-	-	-	-	-
Total	**8.8**	**9.8**	**9.1**	**21.8**	**20.1**	**21.4**

People in Receipt of Benefits (includes people on LTD)

	January 1, 2013			December 31, 2015		
	Male	Female	Total	Male	Female	Total
Number of Members	69	21	90	62	19	81

Expected Annual Benefit Payments for CY 2016 (For Current Retirees Only)

Age Band	Male	Female	Total
Less than 30	-	-	-
30 - 35	-	-	-
36 - 40	-	-	-
41 - 45	-	-	-
46 - 50	-	-	-
51 - 55	3,690	-	3,690
56 - 60	8,460	12,696	21,155
61 - 65	23,631	4,427	28,058
66 - 70	244	36	279
71 - 75	242	99	341
Greater than 75	4,491	564	5,055
Total	**40,757**	**17,821**	**58,577**

PARTICIPATION RECONCILIATION

Table B.2—Participation Reconciliation

Participant Reconciliation

	Actives	Disabled	Retired
As at Jan. 1, 2013	**167**	**4**	**86**
New Entrants	32	-	-
Active	-	1	8
LTD	(1)	-	1
Terminated	(3)	-	-
Deceased	-	-	(3)
Retired	(8)	(1)	-
Corrections to Data	-	-	(15) [1/]
As at Dec. 31, 2015	**187**	**4**	**77**

[1/] *15 retirees which were included in the previous database were indicated in the current valuation as not receiving post-retirement benefits and were therefore excluded from the current valuation.*

SECTION C— SUMMARY OF ACTUARIAL METHOD AND ASSUMPTIONS

ACTUARIAL METHOD

The aim of an actuarial valuation of post-retirement non-pension benefits is to provide a reasonable and systematic allocation of the cost of these future benefits to the years in which the related employees' services are rendered. To accomplish this, it is necessary to:

- make assumptions for discount rates, and mortality and other decrements;
- use these assumptions to calculate the present value of the expected future benefits; and
- adopt an actuarial cost method to allocate the present value of expected future benefits to the specific years of employment.

The Present Value of the Defined Benefit Obligation and Current Service Cost were determined using the projected benefit method, pro-rated on service. This is the method stipulated by IAS 19 when future salary levels or cost escalation affect the amount of the employee's future benefits. Under this method, the projected post-retirement benefits are deemed to be earned on a pro-rata basis over the years of service in the attribution period. IAS 19 stipulates that the attribution period commences on the date when service by the employee first leads to post-retirement non-pension benefits under the plan and ends on the date when further service by the employee will lead to no material amount of further post-retirement non-pension benefits under the plan, other than from further salary increases.

For each employee not yet fully eligible for benefits, the Present Value of the Defined Benefit Obligation is equal to the present value of expected future benefits multiplied by the ratio of the years of service to the valuation date to the total years of service in the attribution period. The Current Service Cost is equal to the present value of expected future benefits multiplied by the ratio of the year (or part) of service in the fiscal year to total years of service in the attribution period.

For health benefits, the Corporation has selected the funding levels charged to retirees as management's best estimate of the benefits costs to be incurred. The total monthly premium rates, inclusive of premium taxes, used are as follows:

Effective Date	Health Single	Health Family
Mar 1, 2015 – Feb 28, 2016	$ 89.08	$ 225.55
Mar 1, 2016 – Feb 28, 2017	$ 86.85	$ 219.91

The above premium rates were provided by the Corporation and represent the rates at 100%, prior to any cost-sharing provisions. A blended cost level for the period January 1, 2016 to December 31, 2016 was calculated based on the time-weighted average of the above rates and used in the valuation.

The PV DBO at December 31, 2015 is based on membership data and management's best estimate assumptions as at December 31, 2015.

MANAGEMENT'S BEST ESTIMATE ASSUMPTIONS

The following are management's best estimate economic and demographic assumptions as at December 31, 2015.

ECONOMIC ASSUMPTIONS

Consumer Price Index

The consumer price index is assumed to be 2.00% per annum, which remains unchanged from the previous valuation.

Discount Rate

The rate used to discount future benefits is assumed to be 4.10% per annum as at December 31, 2015. This rate reflects the Corporation's expected projected benefit cash flows for post-retirement non-pension benefits and the market yields on high quality bonds at December 31, 2015.

The assumption used in the previous valuation was 3.85% per annum as at January 1, 2013, which was subsequently updated to 3.90% per annum as at December 31, 2014.

Claims Cost Trend Rate

The rates used to project health benefit costs into the future are assumed to be as follows:

End of Year	Current Valuation	Previous Valuation
2016	6.50%	6.10%
2017	6.25%	5.80%
2018	6.00%	5.50%
2019	5.75%	5.20%
2020	5.50%	4.90%
2021	5.25%	4.60%
2022	5.00%	4.60%
2023	4.75%	4.60%
2024 and Thereafter	4.50%	4.60%

DEMOGRAPHIC ASSUMPTIONS

Mortality Table

The mortality tables used are as per the Canadian Institute of Actuaries Canadian Pensioners' Mortality Pension Experience Subcommittee final report dated February 11, 2014 (CIA Report). More specifically, the Canada Pensioners Mortality ("CPM") Table Public Sector (CPM2014 PUBL) has been used with the generational projection of mortality improvement based upon CPM Improvement Scale B-2014.

Mortality rates are applied on a sex-distinct basis.

The assumption used in the previous valuation was 1994 Uninsured Pensioner Mortality (UP-94) table, with a generational projection of mortality improvements based upon Project Scale AA. It was subsequently updated at December 31, 2014 to the above-noted CPM Table, along with the one-dimensional version of the corresponding mortality improvement table, CPM Improvement Scale B1-2014.

Rates of Withdrawal

Termination of employment is assumed to be 0.5% per annum prior to age 55.

This assumption remains unchanged from the previous valuation.

Retirement Age

All active employees are assumed to retire at age 59 (or immediately if currently over age 59), which was based on the Corporation's retirement experience as well as a seven year retirement experience study on a group of local distribution companies for which data was available.

This assumption remains unchanged from the previous valuation.

Disability

No provision was made for future disability.

This assumption remains unchanged from the previous valuation.

Family/Single Coverage

It is assumed that the coverage type as at December 31, 2015, as provided by the Corporation, will remain the same until the employee reaches the assumed retirement age. For family coverage, it is assumed that the retiree has a spouse of opposite gender and no other dependents. Male spouses are assumed to be three years older than female spouses.

These assumptions remain unchanged from the previous valuation.

Life and Extended Health Benefits

Upon retirement, it is assumed that 100% of eligible retirees will opt to continue with the life insurance benefit, with 50% of the cost of extending benefits funded by the Corporation. In regards to the extended health benefit it is assumed that 100% of eligible retirees will receive extended health benefits until age 65, with 100% of the cost funded by the Corporation.

This assumption remains unchanged from the previous valuation.

Expenses and Taxes

We have assumed 10% of benefits is required for the cost of sponsoring the program for life insurance. We have assumed taxes and expenses are included in the premium rates for health benefits.

These assumptions remain unchanged from the previous valuation.

SECTION D— SUMMARY OF POST-RETIREMENT BENEFITS

The following is a summary of the plan provisions that are pertinent to this valuation, based on information provided by and discussions with the Corporation.

GOVERNING DOCUMENTS

The program is governed by the following documents:

- Labour Agreement between PUC Services Inc. and the Power Workers' Union CUPE Local 1000 Outside Workers, effective May 1, 2014 to April 30, 2018
- Group Booklet for All Eligible Retired Salaried Employees (Life flat $2,000) of PUC Services Inc. (Group Number 91653-002), issued May 1, 2014
- Group Booklet for All Eligible Retired Salaried Employees of PUC Services Inc. (Group Number 91653-002), issued May 1, 2014
- Group Booklet for Retired Inside Workers (Life flat $2,000) of PUC Services Inc. (Group Number 91653-055), issued May 1, 2014
- Group Booklet for Retired Inside Workers of PUC Services Inc. (Group Number 91653-055), issued May 1, 2014
- Group Booklet for Retired Outside Workers (Life flat $2,000) of PUC Services Inc. (Group Number 91653-033), issued May 1, 2014
- Group Booklet for Retired Outside Workers of PUC Services Inc. (Group Number 91653-033), issued May 1, 2014

What follows is only a summary of the post retirement non-pension benefits program. For a complete description, please refer to the above-noted documents.

ELIGIBILITY

All employees who retire from the Corporation have the option to sign up for post-retirement life insurance benefits and extended health coverage.

PARTICIPANT CONTRIBUTIONS

The Corporation shall pay 50% of the cost of life insurance benefits for all retirees if they choose to sign up for life insurance, except for the retirees with coverage amount of $2,000, of which 100% of the cost will be paid. The Corporation shall pay 100% of the cost of the extended health care until 65 for all retirees if they choose to keep the benefit.

PAST SERVICE

Past service is defined as continuous service prior to joining the plan if the participant was employed by another local distribution company prior to joining the Corporation.

LENGTH OF SERVICE

Length of service is defined as continuous service from the date of hire to the valuation date, measured in years and months.

SUMMARY OF BENEFITS

Life Insurance

All eligible early retirees who choose to sign up for post-retirement life insurance are entitled to lifetime post-retirement life insurance with a flat benefit coverage amount of $5,000, with the exception of a few retirees with a flat benefit coverage amount of $2,000.

Health and Dental Benefits

All eligible employees are entitled to receive post-retirement health benefits to age 65.

A detailed description of the health benefits covered under the post-retirement non-pension benefits can be found in the above-noted governing document.

SECTION E— EMPLOYER CERTIFICATION

**Post-Retirement Non-Pension Benefit Plan
of Sault Ste. Marie PUC Services Inc.
Actuarial Valuation as at December 31, 2015**

I hereby confirm, as an authorized signing officer of the administrator of the Post-Retirement Non-Pension Benefit Plan of Sault Ste. Marie PUC Services Inc. that, to the best of my knowledge and belief, for the purposes of the valuation:

i) the membership data summarized in Section B is accurate and complete;

ii) the assumptions upon which this report is based as summarized in Section C, are management's best estimate assumptions and are adequate and appropriate for the purposes of this valuation; and

iii) the summary of Plan Provisions in Section D is an accurate and complete summary of the terms of the Plan in effect on December 31, 2015.

SAULT STE. MARIE PUC SERVICES INC.

Date	Signature
Name	Title

1/24/2018

RSM

Sault Ste. Marie PUC Services
Estimated Benefit Expense (IAS 19)
Total
FINAL

	Actuals CY 2017 *
Discount Rate at January 1	3.90%
Discount Rate at December 31	3.40%
Health Benefit Cost Trend Rate at December 31	
Initial Trend Rate	6.25%
Ultimate Rate	4.50%
Year Ultimate Rate Reached	2024
Dental Benefit Cost Trend Rate at December 31	4.50%
Assumed Increase in Employer Contributions	actuals

A. Change in the Net Defined Benefit Liability/(Asset) Recognized in Balance Sheet

Net Defined Benefit Liability/(Asset) as at January 1	2,002,449
Defined Benefit Cost Recognized in Income Statement	184,040
Defined Benefit Cost Recognized in Other Comprehensive Income	127,674
Benefits Paid by the Employer	(73,754)
Net Defined Benefit Liability/(Asset) as at December 31	2,240,409

B. Determination of Defined Benefit Cost

B1. Determination of Defined Benefit Cost Recognized in Income Statement

Current Service Cost	107,382
Interest Cost	76,657
Defined Benefit Cost Recognized in Income Statement	184,040

B2. Remeasurements of the Net Defined Benefit Liability/(Asset) Recognized in Other Comprehensive Income

Net Actuarial Loss/(Gain) arising from Changes in Financial Assumptions	127,674
Net Actuarial Loss/(Gain) arising from Changes in Demographic Assumptions	-
Net Actuarial Loss/(Gain) arising from Experience Adjustments	-
Return on Plan Assets (Excluding Amounts Included in Net Interest Cost)	-
Change in Effect of Asset Ceiling	-
Defined Benefit Cost Recognized in Other Comprehensive Income	127,674
Total Defined Benefit Cost	311,713

C. Change in the Present Value of Defined Benefit Obligation

Present Value of Defined Benefit Obligation as at January 1	2,002,449
Current Service Cost	107,382
Interest Cost	76,657
Benefits Paid	(73,754)
Net Actuarial Loss/(Gain)	127,674
Present Value of Defined Benefit Obligation as at December 31	2,240,409

* The CY 2017 defined benefit cost and expected December 31, 2017 PV DBO are calculated based on membership data at December 31, 2015 and management's best estimate assumptions at December 31, 2016.

1/24/2018

RSM

Sault Ste. Marie PUC Services

Estimated Benefit Expense (IAS 19)

Total

FINAL

	Actuals CY 2017 *
Discount Rate at January 1	3.90%
Discount Rate at December 31	3.40%
Health Benefit Cost Trend Rate at December 31	
Initial Trend Rate	6.25%
Ultimate Rate	4.50%
Year Ultimate Rate Reached	2024
Dental Benefit Cost Trend Rate at December 31	4.50%
Assumed Increase in Employer Contributions	actuals

D. Calculation of Component Items

Interest Cost	
Present Value of Defined Benefit Obligation as at January 1	2,002,449
Benefits Paid	(36,877)
Accrued Benefits	1,965,573
Interest Cost	76,657
Expected Present Value of Defined Benefit Obligation as at December 31	
Present Value of Defined Benefit Obligation as at January 1	2,002,449
Current Service Cost	107,382
Benefits Paid	(73,754)
Interest Cost	76,657
Expected Present Value of Defined Benefit Obligation as at December 31	2,112,735

E. Net Actuarial Loss/(Gain)

Net Actuarial Loss/(Gain) as at December 31	
Expected Present Value of Defined Benefit Obligation	2,112,735
Actual Present Value of Defined Benefit Obligation	2,240,409
Net Actuarial Loss/(Gain) as at December 31	127,674

* The CY 2017 defined benefit cost and expected December 31, 2017 PV DBO are calculated based on membership data at December 31, 2015 and management's best estimate assumptions at December 31, 2016.

PUC Distribution Inc.
EB-2017-0071
Filed: March 29, 2018

EXHIBIT 5:
COST OF CAPITAL AND RATE OF RETURN

Table of Contents

Exhibit 5: Cost of Capital and Capital Structure

The purpose of this evidence is to summarize the method and cost of financing capital requirements for the 2018 Test Year. PUC Distribution adopts the OEB's guidelines for cost of capital and understands that these rates are final so that no updates will need to be done.

2.5.1 Capital Structure

PUC Distribution has a current deemed capital structure of 56% long term debt with a return of 3.91%, 4% short term debt with a return of 2.07% and 40% equity with a return of 8.98% as approved in the 2013 cost of service ("COS") rate decision (EB-2012-0162).

PUC Distribution has prepared this 2018 COS Application in accordance with the Board's guidelines provided in the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities* issued on December 11, 2009. For the purposes of preparing this Application, PUC Distribution has used the cost of capital parameters issued by the Board on November 23, 2017 for 2018 cost of service rate applications.

2.5.2 Cost of Capital (Return on Equity and Cost of Debt)

As outlined above, for the purposes of preparing this Application PUC Distribution has used the cost of capital parameters issued by the Board on November 23, 2017 for 2018 COS rate applications which reflects a return on equity of 9.00%

Cost of Debt: Short Term

For the purposes of preparing this Application, PUC Distribution has used the cost of capital parameters issued by the Board on November 23, 2017 for 2018 COS rate applications which reflects a deemed short term debt rate of 2.29%.

Cost of Debt: Long Term

PUC Distribution is requesting a return on long term debt for the 2018 Test Year of 4.12%. This rate of return represents the weighted average cost of long term debt for the following long term debt instruments.

PUC Distribution has a note payable to the parent company, PUC Inc., for $26,534,040 with interest payable at quarterly rates periodically negotiated and principal payable one year after demand. In this application, the interest rate on this note will be based on the Board's cost of capital parameter for long term debt for 2018 cost of service rate applications issued November 23, 2017 which is 4.16%.

PUC Distribution has 3 loans payable to Ontario Infrastructure Projects Corporation (OIPC):

Loan payable #1 to OIPC is an amount of $5,000,000. It is a 15 year debenture with a fixed interest rate of 3.82%. The loan is payable semi-annual principal and interest. Security is in the form of a second ranking general security agreement. This was used to finance the smart meter project.

Loan payable #2 to OIPC was used for the construction of the new integrated service centre/office building. The total amount of the approved loan principal is $21,180,000. The loan is payable over 25 years with interest payable monthly at a fixed interest rate and principal, secured by a mortgage on the land and building and a general security agreement. The fixed interest rate on this loan is 4.61% will be determined once the project is completed.

Loan payable #3 to OIPC is an amount of $15,000,000. It is a 25 year debenture with a fixed interest rate of 3.47%. 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. The proceeds of this loan were used for distribution infrastructure replacement.

Capital Structure and Cost of Capital

Below is a reproduction of Appendix 2-OA that demonstrates the elements of the capital structure and cost of capital from 2013 Board-approved and 2018 Test Year. For 2018, the weighted average cost of capital of 6.00% will be applied to the rate base of $99,603,703, which is explained in detail in Exhibit 2, to determine a return on rate base of $5,975,027 that is included in the proposed revenue requirement.

Appendix 2-OA
Capital Structure and Cost of Capital

This table must be completed for the last Board-approved year and the test year.

Year: 2013

Line No.	**Particulars**	**Capitalization Ratio**			**Cost Rate**	**Return**
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$50,686,521	3.91%	$1,981,843
2	Short-term Debt	4.00%	(1)	$3,620,466	2.07%	$74,944
3	**Total Debt**	60.0%		$54,306,987	3.79%	$2,056,787
	Equity					
4	Common Equity	40.00%		$36,204,658	8.98%	$3,251,178
5	Preferred Shares			$ -		$ -
6	**Total Equity**	40.0%		$36,204,658	8.98%	$3,251,178
7	**Total**	100.0%		$90,511,645	5.86%	$5,307,965

Appendix 2-OA
Capital Structure and Cost of Capital

This table must be completed for the last Board-approved year and the test year.

Year: 2018

Line No.	**Particulars**	**Capitalization Ratio**			**Cost Rate**	**Return**
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$55,778,074	4.12%	$2,298,057
2	Short-term Debt	4.00%	(1)	$3,984,148	2.29%	$91,237
3	**Total Debt**	60.0%		$59,762,222	4.00%	$2,389,294
	Equity					
4	Common Equity	40.00%		$39,841,481	9.00%	$3,585,733
5	Preferred Shares			$ -		$ -
6	**Total Equity**	40.0%		$39,841,481	9.00%	$3,585,733
7	**Total**	100.0%		$99,603,703	6.00%	$5,975,027

Weighted Average Cost of Long-Term Debt

Outlined below is a reproduction of Appendix 2-OB listing PUC Distribution’s long term debt instruments and weighted average cost of long term debt from 2013 to the 2018 test year.

Appendix 2-OB
Debt Instruments

This table must be completed for all required historical years, the bridge year and the test year.

Year 2013

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
4	Promissory Note	PUC Inc.	Affiliated	Fixed Rate	2013	No Term	$ 26,534,040.00	6.10%	$ 1,618,576.44	
5	Promissory Note	Infrastructure Ontario	Third-Party	Fixed Rate	2013	15	$ 5,000,000.00	3.82%	$ 191,000.00	
6	Promissory Note	Infrastructure Ontario	Third-Party	Fixed Rate	2013	25	$ 21,180,000.00	4.61%	$ 976,398.00	
Total							$ 52,714,040	5.29%	$ 2,785,974.44	

Year 2014

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Promissory Note	PUC Inc.	Affiliated	Fixed Rate	2014	No Term	$ 26,534,040.00	6.10%	$ 1,618,576.44	
2	Promissory Note	Infrastructure Ontario	Third-Party	Fixed Rate	2014	15	$ 5,000,000.00	3.82%	$ 191,000.00	
3	Promissory Note	Infrastructure Ontario	Third-Party	Fixed Rate	2014	25	$ 21,180,000.00	4.61%	$ 976,398.00	
4	Promissory Note	Infrastructure Ontario	Third-Party	Variable Rate	2014	No Term	$ 15,000,000.00	1.84%	$ 276,000.00	
Total							$ 67,714,040	4.52%	$ 3,061,974.44	

Year 2015

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Promissory Note	PUC Inc.	Affiliated	Fixed Rate	2015	No Term	$ 26,534,040.00	6.10%	$ 1,618,576.44	
2	Promissory Note	Infrastructure Ontario	Third-Party	Fixed Rate	2015	15	$ 5,000,000.00	3.82%	$ 191,000.00	
3	Promissory Note	Infrastructure Ontario	Third-Party	Fixed Rate	2015	25	$ 21,180,000.00	4.61%	$ 976,398.00	
4	Promissory Note	Infrastructure Ontario	Third-Party	Variable Rate	2015	No Term	$ 15,000,000.00	1.55%	$ 232,500.00	
Total							$ 67,714,040	4.46%	$ 3,018,474.44	

Year 2016

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Promissory Note	PUC Inc.	Affiliated	Fixed Rate	2016	No Term	$ 26,534,040.00	6.10%	$ 1,618,576.44	
2	Promissory Note	Infrastructure Ontario	Third-Party	Fixed Rate	2016	15	$ 5,000,000.00	3.82%	$ 191,000.00	
3	Promissory Note	Infrastructure Ontario	Third-Party	Fixed Rate	2016	25	$ 21,180,000.00	4.61%	$ 976,398.00	
4	Promissory Note	Infrastructure Ontario	Third-Party	Fixed Rate	2016	No Term	$ 15,000,000.00	1.55%	$ 232,500.00	
Total							$ 67,714,040	4.46%	$ 3,018,474.44	

Year 2017

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Promissory Note	PUC Inc.	Affiliated	Fixed Rate	2017	No Term	$ 26,534,040.00	6.10%	$ 1,618,576.44	
2	Promissory Note	Infrastructure Ontario	Third-Party	Fixed Rate	2017	15	$ 5,000,000.00	3.82%	$ 191,000.00	
3	Promissory Note	Infrastructure Ontario	Third-Party	Fixed Rate	2017	25	$ 21,180,000.00	4.61%	$ 976,398.00	
4	Promissory Note	Infrastructure Ontario	Third-Party	Fixed Rate	2017	25	$ 15,000,000.00	3.47%	$ 520,500.00	
Total							$ 67,714,040	4.88%	$ 3,306,474.44	

Year 2018

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Promissory Note	PUC Inc.	Affiliated	Fixed Rate	2018	No Term	$ 26,534,040.00	4.16%	$ 1,103,816.06	
2	Promissory Note	Infrastructure Ontario	Third-Party	Fixed Rate	2018	15	$ 5,000,000.00	3.82%	$ 191,000.00	
3	Promissory Note	Infrastructure Ontario	Third-Party	Fixed Rate	2018	25	$ 21,180,000.00	4.61%	$ 976,398.00	
4	Promissory Note	Infrastructure Ontario	Third-Party	Fixed Rate	2018	25	$ 15,000,000.00	3.47%	$ 520,500.00	
Total							$ 67,714,040	4.12%	$ 2,791,714.06	

Profit or Loss on Redemption of Debt or Preferred Shares

There is no profit or loss on redemption of debt or preferred shares.

Notional Debt

Notional debt is that portion of the deemed debt capitalization that results from differences between the distributor’s actual debt and the deemed debt thickness of 60% (56% long-term debt and 4% short-term debt). PUC Distribution has about ($7.9) million in notional debt in the test year (i.e. deemed debt portion of rate base of $59.8 million minus actual debt of $67.7 million). PUC Distirbution’s plan is to reduce debt to equity to the deemed 60/40% before its next rebasing in 2023.

2.5.3 Not-for-Profit Corporations

PUC Distribution is a for-profit corporation. As a result, the filing requirements associated with not-for-profit corporations are not applicable.

APPENDIX 1

Promissory Note

PROMISSORY NOTE

ISSUED TO: PUC INC. (the "Holder")

ISSUED BY: PUC DISTRIBUTION INC (the "Borrower")

AMOUNT: $30,290,000.00 (the "Principal")

1.0 PROMISE TO PAY

1.1 In consideration of the redemption by the Borrower of 3,029 Special Shares, the Borrower hereby promises to pay to the Holder at 765 Queen Street East. Sault Ste. Marie, Ontario the Principal in lawful money of Canada in the manner hereinafter provided, together with interest and other moneys which may from time to time be owing hereunder or pursuant hereto.

2.0 PRINCIPAL PAYMENTS

2.1 On demand the issuer shall pay to the Holder the balance of Principal, interest and all other monies which may be owing hereunder.

3.0 INTEREST

3.1 This note shall bear interest at the rate of 10% per annum calculated from December 1st, 2001 The first interest payment shall be due on the 31st day of December 2001 and thereafter interest shall be payable quarterly on the last day of March, June, September and December. Notwithstanding the foregoing, the interest rate may be adjusted on a quarterly basis by mutual agreement between the Borrower and the Holder. The Borrower agrees that in the absence of manifest error, the record kept by the Holder on this Note of such changes in the interest rate shall be conclusive evidence of the matters recorded

3.2 Interest shall also be calculated and payable on overdue interest from time to time outstanding at the rate in effect at the date of default.

4.0 DEFAULT

4.1 In the event of default, the full unpaid balance of the Principal and all accrued and unpaid interest thereon shall at the option of the Holder forthwith become due and payable.

5.0 PREPAYMENTS

5.1 The Borrower may, at any time, prepay the outstanding aggregate Principal amount of this Note whether in whole or in part without notice, bonus or penalty.

6.0 WAIVER

6.1 Presentment for payment, demand, protest, notice of protest and notice of dishonour of this Note are hereby waived.

7.0 SUCCESSORS AND ASSIGNS

7.1 The Holder shall not assign any interest in this Note without the prior written consent of the Borrower, which consent shall not be unreasonably withheld or delayed. This Note shall be binding upon the Borrower and its successors and assigns and shall enure to the benefit of the Holder and successors and permitted assigns.

8.0 GOVERNING LAW

8.1 The Note shall be governed and construed in accordance with the laws of the Province of Ontario and the federal laws of Canada applicable therein.

9.0 COLLECTION COSTS

9.1 To the extent permitted by applicable law, the Borrower agrees to pay all costs of collection including, without limitation, reasonable solicitor's fees, disbursements and expenses on a solicitor and his own client basis incurred by the Holder in connection with the enforcement of this Note.

10.0 TIME OF ESSENCE

10.1 Time is of the essence.

11.0 INTERPRETATION

11.1 The division of this Note into sections and insertion of the headings in this Note are for convenience of reference only and shall not affect the construction or interpretation of this Note.

IN WITNESS whereof the Borrower has executed this Note as of the 1st day of December, 2001.

PUC DISTRIBUTION INC.

Per:

Brian Curran, President

Per:

Clyde Hesley, Secretary

We have authority to bind the Corporation

DATE	INTEREST RATE	NOTATION MADE BY

NOTICE

TO: PUC DISTRIBUTION INC.
765 Queen Street East
Sault Ste. Marie, Ontario
P6A 6P2

Re: Exercise of Option – Promissory Note dated December 1st , 2001 (the "Note") between PUC Distribution Inc. (the "Borrower") and PUC Inc. (the "Holder") in the principal amount of Thirty Million Two Hundred and Ninety Thousand Dollars $30,290,000.00 (the "Principal")

TAKE NOTICE that pursuant to paragraph 1.2 of the Note the Holder hereby exercises its option to convert the sum of Three Million Seven Hundred and Fifty Five Thousand Nine Hundred and Sixty Dollars ($3,755,960.00) of the Principal into One Thousand Six Hundred and Twelve (1,612) Common Shares in the capital stock of the Borrower, effective December 31st, 2008. Upon issuance of the Shares the Principal of the Note shall be Twenty Six Million and Five Hundred and Thirty Four Thousand and Forty Dollars ($26,534,040).

DATED this 18th day of December, 2008.

PUC INC.

Per:
Brian Curran – President

Per: Greco
Terry Greco – Treasurer

We have authority to bind the Corporation

PUC DISTRIBUTION INC. RESOLUTION

Agenda Item # 5.2 **Date:** December 18, 2008

Moved by: LARRY GUERRIERO

Seconded by: RICK WING

Resolution:

"RESOLVED that pursuant to the Notice from PUC Inc. dated December 18th, 2008 delivered to the Corporation and produced to the Board of Directors wherein PUC Inc. exercised its option to convert the principal amount of the Promissory Note between the Corporation as Borrower and PUC Inc. as Holder dated August 15th, 2001 in the amount of $11,650,000.00 into 5,000 common shares in the capital stock of the Corporation at the rate of $2,330.00 per share. The Corporation is hereby authorized to issue to PUC Inc. as at December 31st, 2008, 5000 Common Shares in the capital stock of the Corporation as fully paid and non-assessable and the President of the Corporation is hereby authorized to deliver certificates for such Shares to PUC Inc. or in accordance with its direction.

BE IT FURTHER RESOLVED that pursuant to the Notice from PUC Inc. delivered to the Corporation and produced to the Board of Directors wherein PUC Inc. exercised its option to convert the sum of $3,755,960.00 of the principal of the Promissory Note between the Corporation as Borrower and PUC Inc. as Holder dated December 1st, 2001 in the amount of $30,290,000.00 into 1,612 common shares in the capital stock of the Corporation at the rate of $2,330.00 per share. The Corporation is hereby authorized to issue to PUC Inc. as at December 31st, 2008, 1,612 common shares in the capital stock of the Corporation as fally paid and non-assessable and the President of the Corporation is hereby authorized to deliver certificates for such Shares to PUC Inc. or in accordance with its direction."

☐ Carried ☐ Defeated ☐ Deferred

☐ Referred ☐ Amended ☐ Officially Read Not Dealt With

Chair

Action

☐ Chair ☐ PUC Inc. ☐ ____________

☐ President ☐ PUC Telecom ☐ ____________

☐ Secretary ☐ PUC Services ☐ ____________

☐ Treasurer ☐ PUC Energies ☐ ____________

EXHIBIT 6:
CALCULATION OF REVENUE DEFICIENCY OR SUFFICIENCY

Table of Contents

Exhibit 6: Calculation of Revenue Deficiency or Sufficiency

PUC Distribution revenue deficiency is $3,679,687. This deficiency is calculated as the difference between the 2018 Test Year Revenue Requirement of $22,081,244 and the Forecast 2018 Test Year Revenue, based on the 2017 approved rates, at $18,401,558. Table 6-1 on the following page provides the revenue deficiency calculations. The table also includes the determination of net utility income, statement of rate base, the utility return on rate base at existing rates and the requested rate of return on rate base in this application. Further details on these items are provided in the pdf version of the Revenue Requirement Work Form (“RRWF”) filed as part of this Exhibit 6 as Appendix 1. A live Microsoft Excel version of the RRWF has also been filed with this Application.

Revenue Requirement

PUC Distribution’s Revenue Requirement consists of the following:

- Administrative & General, Billing & Collecting Expense
- Operation & Maintenance Expense
- Depreciation Expense
- Property Taxes
- PILs
- Deemed Interest & Return on Equity

PUC Distribution’s revenue requirement is primarily received through electricity distribution rates with supplemental revenue from Board-approved specific service charges such as late payment charges and other miscellaneous charges.

Table 6-1 Revenue Deficiency Calculation

Description	2018 Test Existing Rates	2018 Test - Required Revenue
Revenue		
Revenue Deficiency		**3,679,687**
Distribution Revenue	16,011,897	16,011,897
Other Operating Revenue (Net)	2,389,661	2,389,661
Total Revenue	**18,401,558**	**22,081,244**
Costs and Expenses		
Administrative & General, Billing & Collecting	5,674,204	5,674,204
Operation & Maintenance	6,212,629	6,212,629
Donations - LEAP	24,000	24,000
Depreciation & Amortization	3,783,956	3,783,956
Property Taxes	45,000	45,000
Deemed Interest	2,389,294	2,389,294
Total Costs and Expenses	**18,129,082**	**18,129,082**
Utility Income Before Income Taxes	**272,475**	**3,952,162**
Income Taxes:		
Corporate Income Taxes	-608,688	366,429
Total Income Taxes	**-608,688**	**366,429**
Utility Net Income	**881,164**	**3,585,733**
Income Tax Expense Calculation:		
Accounting Income	272,475	3,952,162
Tax Adjustments to Accounting Income	-2,569,412	-2,569,412
Taxable Income	**-2,296,937**	**1,382,750**
Income tax expense before credits	**-608,688**	**366,429**
Credits	**0**	**0**
Income Tax Expense	-608,688	366,429
Tax Rate Refecting Tax Credits	26.50%	26.50%
Actual Return on Rate Base:		
Rate Base	99,603,703	99,603,703
Interest Expense	2,389,294	2,389,294
Net Income	881,164	3,585,733
Total Actual Return on Rate Base	**3,270,457**	**5,975,027**
Actual Return on Rate Base	3.28%	6.00%
Required Return on Rate Base:		
Rate Base	99,603,703	99,603,703
Return Rates:		
Return on Debt (Weighted)	4.00%	4.00%
Return on Equity	9.00%	9.00%
Deemed Interest Expense	2,389,294	2,389,294
Return On Equity	3,585,733	3,585,733
Total Return	**5,975,027**	**5,975,027**
Expected Return on Rate Base	6.00%	6.00%
Revenue Deficiency After Tax	**2,704,570**	**0**
Revenue Deficiency Before Tax	**3,679,687**	**0**

Cost Drivers on Revenue Deficiency

Table 6-2 below outlines the contributors to the revenue deficiency by revenue requirement component. Column A lists PUC Distribution's 2013 approved amounts. Column B lists the PUC Distribution revenue at existing rates shown in Table 6-1 allocated to revenue requirement component based on the proportions in Column A. It is PUC Distribution's view that Column B estimates the revenue requirement components for revenue at existing rates based on the components assumed in existing rates. Column C lists the PUC Distribution's proposed components. Finally, Column D represents the difference between Column C and Column B which provides an estimate of the revenue requirement components for the revenue deficiency of $3,679,687.

Table 6-2 Revenue Deficiency by Revenue Requirement Component

Service Revenue Requirement	**2013 Approved (A)**	**2018 Revenue at Existing Rates Allocated in Proportion to 2013 Approved (B)**	**2018 Proposed (C)**	**Revenue Deficiency (D) = (C) - (B)**
OM&A	9,902,946	9,671,793	11,886,833	2,215,039
LEAP	0	0	24,000	24,000
Property Tax	50,000	48,833	45,000	($3,833)
Depreciation	3,348,256	3,270,101	3,783,956	513,855
Return on Rate Base	5,290,883	5,167,384	5,975,027	807,643
PILs	249,265	243,447	366,429	122,982
Total	18,841,350	18,401,558	22,081,245	**3,679,686**
				Difference (D) = (C) - (A)
Rate Base	90,511,645		99,603,703	9,092,058

61% of the revenue deficiency of $3,679,687 for the 2018 Test Year relates to increases to OM&A including LEAP which are explained in detail in Exhibit 4. In summary, the main contributors to the increases in OM&A are:

Increased line clearing	$140,000
Additional MIST metering for general service customers	$45,000
Increased OEB fees	$60,000
Increased bad debt expense	$150,000
Increased TOU billing expenses	$100,000
Increased regulatory rate filing costs	$120,000
Additional transformer PCB testing	$80,000
Additional station maintenance to be compliant with IESO	$200,000
Additional regulatory staff	$100,000
Inflationary increases over 5 years	$1,240,206
	$2,235,206

The remaining 39% of the revenue deficiency of $3,679,687 relates to increases in capital related items such as Depreciation ($513,855), Return on Rate Base ($807,643) and PILs ($122,982). The main contributors to these costs are:

- 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
- Increased taxable income causing an increase in PILs payable

APPENDIX 1

Revenue Requirement Work Form

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2018 Filers

Version 7.02

Utility Name	PUC Distribution Inc.
Service Territory	Sault Ste. Marie, Ontario
Assigned EB Number	EB-2017-0071
Name and Title	Andrew Belsito, Rates and Regulatory Affairs Officer
Phone Number	705-759-3009
Email Address	andrew.belsito@ssmpuc.com

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

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2018 Filers

Notes:

(1) Pale green cells represent inputs

(2) Pale green boxes at the bottom of each page are for additional notes

(3) Pale yellow cells represent drop-down lists

(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***

(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2018 Filers

Data Input (1)

		Initial Application	(2)			(6)			Per Board Decision	
1	**Rate Base**									
	Gross Fixed Assets (average)	$108,487,326			$ 108,487,326				$108,487,326	
	Accumulated Depreciation (average)	($15,769,425)	(5)		($15,769,425)				($15,769,425)	
	Allowance for Working Capital:									
	Controllable Expenses	$11,955,833			$ 11,955,833				$11,955,833	
	Cost of Power	$79,854,870			$ 79,854,870				$79,854,870	
	Working Capital Rate (%)	7.50%	(9)		7.50%	(9)			7.50%	(9)
2	**Utility Income**									
	Operating Revenues:									
	Distribution Revenue at Current Rates	$16,011,897			$16,011,897		$0		$16,011,897	
	Distribution Revenue at Proposed Rates	$19,691,584			$19,691,584		$0		$19,691,584	
	Other Revenue:									
	Specific Service Charges	$170,100		$0	$170,100		$0		$170,100	
	Late Payment Charges	$259,000		$0	$259,000		$0		$259,000	
	Other Distribution Revenue	$1,848,061		$0	$1,848,061		$0		$1,848,061	
	Other Income and Deductions	$112,500		$0	$112,500		$0		$112,500	
	Total Revenue Offsets	$2,389,661	(7)	$0	$2,389,661		$0		$2,389,661	
	Operating Expenses:									
	OM+A Expenses	$11,886,833			$ 11,886,833				$11,886,833	
	Depreciation/Amortization	$3,783,956			$ 3,783,956				$3,783,956	
	Property taxes	$45,000			$ 45,000				$45,000	
	Other expenses	$24,000			24000				$24,000	
3	**Taxes/PILs**									
	Taxable Income:									
	Adjustments required to arrive at taxable income	($2,569,412)	(3)		($2,569,412)				($2,569,412)	
	Utility Income Taxes and Rates:									
	Income taxes (not grossed up)	$269,325			$269,325				$269,325	
	Income taxes (grossed up)	$366,429			$366,429				$366,429	
	Federal tax (%)	11.50%			11.50%				11.50%	
	Provincial tax (%)	15.00%			15.00%				15.00%	
	Income Tax Credits									
4	**Capitalization/Cost of Capital**									
	Capital Structure:									
	Long-term debt Capitalization Ratio (%)	56.0%			56.0%				56.0%	
	Short-term debt Capitalization Ratio (%)	4.0%	(8)		4.0%	(8)			4.0%	(8)
	Common Equity Capitalization Ratio (%)	40.0%			40.0%				40.0%	
	Prefered Shares Capitalization Ratio (%)									
		100.0%			100.0%				100.0%	
	Cost of Capital									
	Long-term debt Cost Rate (%)	4.12%			4.12%				4.12%	
	Short-term debt Cost Rate (%)	2.29%			2.29%				2.29%	
	Common Equity Cost Rate (%)	9.00%			9.00%				9.00%	
	Prefered Shares Cost Rate (%)									

Notes:

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

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

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

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

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

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

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

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

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

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

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application				Per Board Decision
1	Gross Fixed Assets (average)	(2)	$108,487,326	$ -	$108,487,326	$ -	$108,487,326
2	Accumulated Depreciation (average)	(2)	($15,769,425)	$ -	($15,769,425)	$ -	($15,769,425)
3	Net Fixed Assets (average)	(2)	$92,717,901	$ -	$92,717,901	$ -	$92,717,901
4	Allowance for Working Capital	(1)	$6,885,803	$ -	$6,885,803	$ -	$6,885,803
5	**Total Rate Base**		$99,603,703	$ -	$99,603,703	$ -	$99,603,703

(1) Allowance for Working Capital - Derivation

Line No.							
6	Controllable Expenses		$11,955,833	$ -	$11,955,833	$ -	$11,955,833
7	Cost of Power		$79,854,870	$ -	$79,854,870	$ -	$79,854,870
8	Working Capital Base		$91,810,703	$ -	$91,810,703	$ -	$91,810,703
9	Working Capital Rate %	(1)	7.50%	0.00%	7.50%	0.00%	7.50%
10	Working Capital Allowance		$6,885,803	$ -	$6,885,803	$ -	$6,885,803

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2018 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

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

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2018 Filers

Utility Income

Line No.	Particulars		Initial Application				Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$19,691,584	$ -	$19,691,584	$ -	$19,691,584
2	Other Revenue	(1)	$2,389,661	$ -	$2,389,661	$ -	$2,389,661
3	Total Operating Revenues		$22,081,245	$ -	$22,081,245	$ -	$22,081,245
	Operating Expenses:						
4	OM+A Expenses		$11,886,833	$ -	$11,886,833	$ -	$11,886,833
5	Depreciation/Amortization		$3,783,956	$ -	$3,783,956	$ -	$3,783,956
6	Property taxes		$45,000	$ -	$45,000	$ -	$45,000
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$24,000	$ -	$24,000	$ -	$24,000
9	Subtotal (lines 4 to 8)		$15,739,789	$ -	$15,739,789	$ -	$15,739,789
10	Deemed Interest Expense		$2,389,294	$ -	$2,389,294	$ -	$2,389,294
11	Total Expenses (lines 9 to 10)		$18,129,083	$ -	$18,129,083	$ -	$18,129,083
12	**Utility income before income taxes**		$3,952,162	$ -	$3,952,162	$ -	$3,952,162
13	Income taxes (grossed-up)		$366,429	$ -	$366,429	$ -	$366,429
14	**Utility net income**		$3,585,733	$ -	$3,585,733	$ -	$3,585,733

Notes

Other Revenues / Revenue Offsets

Note	Particulars	Initial Application				Per Board Decision
(1)	Specific Service Charges	$170,100	$ -	$170,100	$ -	$170,100
	Late Payment Charges	$259,000	$ -	$259,000	$ -	$259,000
	Other Distribution Revenue	$1,848,061	$ -	$1,848,061	$ -	$1,848,061
	Other Income and Deductions	$112,500	$ -	$112,500	$ -	$112,500
	Total Revenue Offsets	$2,389,661	$ -	$2,389,661	$ -	$2,389,661

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2018 Filers

Taxes/PILs

Line No.	Particulars	Application		Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$3,585,733	$3,585,733	$3,585,733
2	Adjustments required to arrive at taxable utility income	($2,569,412)	($2,569,412)	($2,569,412)
3	Taxable income	$1,016,321	$1,016,321	$1,016,321
	Calculation of Utility income Taxes			
4	Income taxes	$269,325	$269,325	$269,325
6	Total taxes	$269,325	$269,325	$269,325
7	Gross-up of Income Taxes	$97,104	$97,104	$97,104
8	Grossed-up Income Taxes	$366,429	$366,429	$366,429
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$366,429	$366,429	$366,429
10	Other tax Credits	$ -	$ -	$ -
	Tax Rates			
11	Federal tax (%)	11.50%	11.50%	11.50%
12	Provincial tax (%)	15.00%	15.00%	15.00%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$55,778,074	4.12%	$2,298,057
2	Short-term Debt	4.00%	$3,984,148	2.29%	$91,237
3	**Total Debt**	60.00%	$59,762,222	4.00%	$2,389,294
	Equity				
4	Common Equity	40.00%	$39,841,481	9.00%	$3,585,733
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$39,841,481	9.00%	$3,585,733
7	**Total**	100.00%	$99,603,703	6.00%	$5,975,027

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$55,778,074	4.12%	$2,298,057
2	Short-term Debt	4.00%	$3,984,148	2.29%	$91,237
3	**Total Debt**	60.00%	$59,762,222	4.00%	$2,389,294
	Equity				
4	Common Equity	40.00%	$39,841,481	9.00%	$3,585,733
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$39,841,481	9.00%	$3,585,733
7	**Total**	100.00%	$99,603,703	6.00%	$5,975,027

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$55,778,074	4.12%	$2,298,057
9	Short-term Debt	4.00%	$3,984,148	2.29%	$91,237
10	**Total Debt**	60.00%	$59,762,222	4.00%	$2,389,294
	Equity				
11	Common Equity	40.00%	$39,841,481	9.00%	$3,585,733
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$39,841,481	9.00%	$3,585,733
14	**Total**	100.00%	$99,603,703	6.00%	$5,975,027

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2018 Filers

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application				Per Board Decision	
		At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		$3,679,687		$3,679,687		$3,679,687
2	Distribution Revenue	$16,011,897	$16,011,897	$16,011,897	$16,011,897	$16,011,897	$16,011,897
3	Other Operating Revenue Offsets - net	$2,389,661	$2,389,661	$2,389,661	$2,389,661	$2,389,661	$2,389,661
4	**Total Revenue**	$18,401,558	$22,081,245	$18,401,558	$22,081,245	$18,401,558	$22,081,245
5	Operating Expenses	$15,739,789	$15,739,789	$15,739,789	$15,739,789	$15,739,789	$15,739,789
6	Deemed Interest Expense	$2,389,294	$2,389,294	$2,389,294	$2,389,294	$2,389,294	$2,389,294
8	**Total Cost and Expenses**	$18,129,083	$18,129,083	$18,129,083	$18,129,083	$18,129,083	$18,129,083
9	**Utility Income Before Income Taxes**	$272,475	$3,952,162	$272,475	$3,952,162	$272,475	$3,952,162
10	Tax Adjustments to Accounting Income per 2013 PILs model	($2,569,412)	($2,569,412)	($2,569,412)	($2,569,412)	($2,569,412)	($2,569,412)
11	**Taxable Income**	($2,296,937)	$1,382,750	($2,296,937)	$1,382,750	($2,296,937)	$1,382,750
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	($608,688)	$366,429	($608,688)	$366,429	($608,688)	$366,429
14	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
15	**Utility Net Income**	$881,163	$3,585,733	$881,163	$3,585,733	$881,163	$3,585,733
16	**Utility Rate Base**	$99,603,703	$99,603,703	$99,603,703	$99,603,703	$99,603,703	$99,603,703
17	Deemed Equity Portion of Rate Base	$39,841,481	$39,841,481	$39,841,481	$39,841,481	$39,841,481	$39,841,481
18	Income/(Equity Portion of Rate Base)	2.21%	9.00%	2.21%	9.00%	2.21%	9.00%
19	Target Return - Equity on Rate Base	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%
20	Deficiency/Sufficiency in Return on Equity	-6.79%	0.00%	-6.79%	0.00%	-6.79%	0.00%
21	Indicated Rate of Return	3.28%	6.00%	3.28%	6.00%	3.28%	6.00%
22	Requested Rate of Return on Rate Base	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%
23	Deficiency/Sufficiency in Rate of Return	-2.72%	0.00%	-2.72%	0.00%	-2.72%	0.00%
24	Target Return on Equity	$3,585,733	$3,585,733	$3,585,733	$3,585,733	$3,585,733	$3,585,733
25	Revenue Deficiency/(Sufficiency)	$2,704,570	$ -	$2,704,570	$ -	$2,704,570	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$3,679,687 (1)		$3,679,687 (1)		$3,679,687 (1)	

Notes:

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

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2018 Filers

Revenue Requirement

Line No.	Particulars	Application				Per Board Decision	
1	OM&A Expenses	$11,886,833		$11,886,833		$11,886,833	
2	Amortization/Depreciation	$3,783,956		$3,783,956		$3,783,956	
3	Property Taxes	$45,000		$45,000		$45,000	
5	Income Taxes (Grossed up)	$366,429		$366,429		$366,429	
6	Other Expenses	$24,000		$24,000		$24,000	
7	Return						
	Deemed Interest Expense	$2,389,294		$2,389,294		$2,389,294	
	Return on Deemed Equity	$3,585,733		$3,585,733		$3,585,733	
8	**Service Revenue Requirement (before Revenues)**	$22,081,245		$22,081,245		$22,081,245	
9	Revenue Offsets	$2,389,661		$2,389,661		$2,389,661	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$19,691,584		$19,691,584		$19,691,584	
11	Distribution revenue	$19,691,584		$19,691,584		$19,691,584	
12	Other revenue	$2,389,661		$2,389,661		$2,389,661	
13	**Total revenue**	$22,081,245		$22,081,245		$22,081,245	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ -	(1)	$ -	(1)	$ -	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application		Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$22,081,245	$22,081,245	**$0**	$22,081,245	**($1)**
Grossed-Up Revenue Deficiency/(Sufficiency)	$3,679,687	$3,679,687	**$0**	$3,679,687	**($1)**
Base Revenue Requirement (to be recovered from Distribution Rates)	$19,691,584	$19,691,584	**$0**	$19,691,584	**($1)**
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$3,679,687	$3,679,687	**$0**	$3,679,687	**($1)**

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2018 Filers

Load Forecast Summary

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

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

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

Stage in Process: Initial Application

	Customer Class	**Initial Application**						**Per Board Decision**		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [(1)] Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [(1)] Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [(1)] Annual
1	Residential	29,789	296,393,596	-						
2	General Service Less than 50 kW	3,443	94,320,130	-						
3	General Service 50 to 4,999 kW	353	248,349,153	624,500						
4	Unmetered Scattered Load	23	1,176,822	-						
5	Sentinel Lighting	348	218,403	616						
6	Street Lighting	8,070	2,415,793	7,076						
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20										
	Total	**42,026**	**642,873,897**	**632,192**		**-**	**-**		**-**	**-**

Notes:

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

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2018 Filers

Cost Allocation and Rate Design

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

Stage in Application Process: ***Initial Application***

A) Allocated Costs

	Name of Customer Class [3] From Sheet 10. Load Forecast	Costs Allocated from Previous Studv [1]	%	Allocated Class Revenue Requirement [1] (7A)	%
1	Residential	$ 11,580,870	61.47%	$ 14,193,143	64.28%
2	General Service Less than 50 kW	$ 2,673,048	14.19%	$ 3,048,990	13.81%
3	General Service 50 to 4,999 kW	$ 3,475,269	18.44%	$ 4,543,021	20.57%
4	Unmetered Scattered Load	$ 33,369	0.18%	$ 45,677	0.21%
5	Sentinel Lighting	$ 45,301	0.24%	$ 46,411	0.21%
6	Street Lighting	$ 1,033,492	5.49%	$ 204,002	0.92%
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20					
	Total	$ 18,841,349	100.00%	**$ 22,081,244**	100.00%

Service Revenue Requirement (from Sheet 9) **$ 22,081,244.70**

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.

(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.

(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	**Load Forecast (LF) X current approved rates** (7B)	**LF X current approved rates X (1+d)** (7C)	**LF X Proposed Rates** (7D)	**Miscellaneous Revenues** (7E)
1	Residential	$ 9,084,381	$ 11,172,059	$ 11,487,469	$ 1,567,716
2	General Service Less than 50 kW	$ 2,640,479	$ 3,247,287	$ 3,247,287	$ 323,010
3	General Service 50 to 4,999 kW	$ 3,797,584	$ 4,670,305	$ 4,670,305	$ 441,680
4	Unmetered Scattered Load	$ 39,984	$ 49,173	$ 47,454	$ 7,358
5	Sentinel Lighting	$ 29,086	$ 35,771	$ 35,771	$ 8,392
6	Street Lighting	$ 420,382	$ 516,990	$ 203,298	$ 41,505
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	Total	$ 16,011,897	$ 19,691,585	$ 19,691,584	$ 2,389,661

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.

(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.

(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.

(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year: 2013 %	Status Quo Ratios (7C + 7E) / (7A) %	Proposed Ratios (7D + 7E) / (7A) %	Policy Range %
1	Residential	92.68%	89.76%	91.98%	85 - 115
2	General Service Less than 50 kW	113.44%	117.10%	117.10%	80 - 120
3	General Service 50 to 4,999 kW	119.53%	112.52%	112.52%	80 - 120
4	Unmetered Scattered Load	100.13%	123.76%	120.00%	80 - 120
5	Sentinel Lighting	83.03%	95.16%	95.16%	80 - 120
6	Street Lighting	82.33%	273.77%	120.00%	80 - 120
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(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

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

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

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

	Name of Customer Class	Proposed Revenue-to-Cost Ratio			Policy Range
		Test Year	Price Cap IR Period		
		2018	2019	2020	
1	Residential	91.98%	91.98%	91.98%	85 - 115
2	General Service Less than 50 kW	117.10%	117.10%	117.10%	80 - 120
3	General Service 50 to 4,999 kW	112.52%	112.52%	112.52%	80 - 120
4	Unmetered Scattered Load	120.00%	120.00%	120.00%	80 - 120
5	Sentinel Lighting	95.16%	95.16%	95.16%	80 - 120
6	Street Lighting	120.00%	120.00%	120.00%	80 - 120
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(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2018 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2019 and 2020 Price Cap IR models, as necessary. For 2019 and 2020, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2017 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2018 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential Class	
Customers	29,789
kWh	296,393,596

Proposed Residential Class Specific Revenue Requirement[1]	$ 11,487,469.00

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	$ 21.23
Distribution Volumetric Rate ($/kWh)	$ 0.0132

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed	21.2	29,789	$ 7,589,564.55	66.07%
Variable	0.013151108	296,393,596	$ 3,897,904.08	33.93%
TOTAL	-	-	$ 11,487,468.63	-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	3

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed	$ 7,589,564.80	21.23	$ 7,589,045.64
Variable	$ 3,897,904.20	0.0132	$ 3,912,395.47
TOTAL	$ 11,487,469.00	-	$ 11,501,441.11

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed	77.38%	$ 8,888,866.20	$ 24.87	$ 8,890,229.16
Variable	22.62%	$ 2,598,602.80	$ 0.0088	$ 2,608,263.64
TOTAL	-	$ 11,487,469.00	-	$ 11,498,492.80

Checks[3]	
Change in Fixed Rate	$ 3.64
Difference Between Revenues @ Proposed Rates and Class Specific Revenue Requirement	$11,023.80 0.10%

Notes:

[1] The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

[2] The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

[3] Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2018 Filers

Rate Design and Revenue Reconciliation

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

Stage in Process: *Initial Application*

	Customer and Load Forecast					Class Allocated Revenues			Fixed / Variable Splits [2]			Distribution Rates					Revenue Reconciliation		
						From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design			Percentage to be entered as a fraction between 0 and 1			Monthly Service Charge		Volumetric Rate					
	Customer Class From sheet 10. Load Forecast	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)	Rate	No. of decimals	Rate		No. of decimals	MSC Revenues	Volumetric revenues	Revenues less Transformer Ownership Allowance
1	Residential	kWh	29,789	296,393,596	-	$ 11,487,469	$ 8,889,004	$ 2,598,465	77.38%	22.62%		$24.87	2	$0.0088	/kWh	4	$ 8,890,229.16	$ 2,608,263.6448	$ 11,498,492.80
2	General Service Less than 50 kW	kWh	3,443	94,320,130	-	$ 3,247,287	$ 869,373	$ 2,377,914	26.77%	73.23%		$21.04		$0.0252	/kWh		$ 869,288.64	$ 2,376,867.2760	$ 3,246,155.92
3	General Service 50 to 4,999 kW	kW	353	248,349,153	624,500	$ 4,670,305	$ 596,276	$ 4,074,029	12.77%	87.23%	$ 82,800	$140.76		$6.6563	/kW		$ 596,259.36	$ 4,156,859.3500	$ 4,670,318.71
4	Unmetered Scattered Load	kWh	23	1,176,822	-	$ 47,454	$ 4,157	$ 43,297	8.76%	91.24%		$15.06		$0.0368	/kWh		$ 4,156.56	$ 43,307.0496	$ 47,463.61
5	Sentinel Lighting	kW	348	218,403	616	$ 35,771	$ 15,048	$ 20,723	42.07%	57.93%		$3.60		$33.6416	/kW		$ 15,033.60	$ 20,723.2256	$ 35,756.83
6	Street Lighting	kW	8,070	2,415,793	7,076	$ 203,298	$ 137,686	$ 65,612	67.73%	32.27%		$1.42		$9.2724	/kW		$ 137,512.80	$ 65,611.5024	$ 203,124.30
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Total Transformer Ownership Allowance $ 82,800

Total Distribution Revenues	$	19,701,312.17
Base Revenue Requirement	$	19,691,583.70
Difference	$	9,728.47
% Difference		0.049%

Rates recover revenue requirement

Notes:

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

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

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2018 Filers

Tracking Form

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

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

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

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

Summary of Proposed Changes

		Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
Reference (1)	Item / Description (2)	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
	Original Application	$ 5,975,027	6.00%	$ 99,603,703	$ 91,810,703	$ 6,885,803	$ 3,783,956	$ 366,429	$ 11,886,833	$ 22,081,245	$ 2,389,661	$ 19,691,584	$ 3,679,687

PUC Distribution Inc.
EB-2017-0071
Filed: March 29, 2018

EXHIBIT 7:
COST ALLOCATION

Table of Contents

Exhibit 7: Cost Allocation Overview

2.7.1 Cost Allocation Study Requirements

In this application, PUC Distribution has used the 2018 version of the cost allocation model released by the OEB on July 14, 2017. The model has been loaded with 2018 test year costs, customer numbers and demand values for PUC Distribution. The 2018 demand values were based on the 2018 weather normalized load forecast used to design rates. The various weighting factors used in the 2018 study have been updated and explained below.

Weighting Factors

PUC Distribution has developed weighting factors as outlined below based on discussions with staff experienced in the subject area. Labour, materials and outside costs required to perform the specific tasks below were estimated to determine each rate class factor. PUC Distribution assigned a weighting factor of 1 to the Residential rate class and further calculated the associated weighting factors for the remaining rate classes.

Services (Account 1855)

Table 7-1: Service Weighting Factors

Rate Class	Factor
Residential	1.0
General Service < 50 kW	0.7
General Service 50 to 4,999 kW	0.4
Sentinel Lighting	0.05
Street Lights	0.05
Unmetered Scattered Load	0.05

Billing and Collection (Accounts 5315 – 5340, except 5335)

Table 7-2: Billing Weighting Factors

Rate Class	Factor
Residential	1.0
General Service < 50 kW	1.1
General Service 50 to 4,999 kW	4.0
Sentinel Lighting	0.8
Street Lights	0.8
Unmetered Scattered Load	0.8

Meter Capital (Sheet I7.1)

Table 7-3: Meter Capital Installation Costs

Meter Type	Installation Cost per Meter
Smart Meter - Residential	$205
Smart Meter - General Service < 50 kW	$587
Smart Meter - General Service 50 to 4,999 kW	$1,006

Meter Reading (Sheet I7.2)

Table 7-4: Meter Reading Weighting Factor

Meter Type	Factor
Smart Meter - Residential	1.0
Smart Meter - General Service < 50 kW	1.0
Smart Meter - General Service 50 to 4,999 kW	19.81

Summary of Results and Proposed Changes

The data used in the updated cost allocation study is consistent with PUC Distribution's cost data that supports the proposed 2018 revenue requirement outlined in this application. PUC Distribution's assets were broken out into primary and secondary distribution functions using breakout percentages used in PUC Distribution's 2013 cost of service rate application (EB-2012-0162). 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, its engineering records, and its customer and financial information systems. An Excel version of the updated cost allocation study has been included with the filed application material. In addition, Appendix 1 outlines Input Sheets I-6 & I-8 and Output Sheets O-1 & O-2 (first page only).

Capital contributions, depreciation and accumulated depreciation by USoA are consistent with the information provided in the 2018 continuity statement shown in Exhibit 2. The rate class customer data used in the updated cost allocation study is consistent with the 2018 customer forecast outlined in Exhibit 3.

The load profiles for each rate class are the same as those used in the 2013 study but have been scaled to match the 2018 load forecast. In a letter, dated June 12, 2015, the OEB stated that it expected distributors to be mindful of material changes to load profiles and to propose updates in their respective cost of service applications when warranted. PUC Distribution is not aware of any reason for the load profiles to have materially changed between the classes. As a result, PUC Distribution has not updated its load profiles at this time. PUC Distribution intends to put plans in place to update its load profiles prior to its next cost of service application.

PUC Distribution proposes to use the same method as was used in the 2013 Cost of Service application for PUC Distribution to determine the demand data for the 2018 cost allocation model. This method involves applying a scaling factor to the 2013 demand data in the 2013 cost allocation model to determine the 2018 demand data for cost allocation. The scaling factor represents by class the percentage of 2018 weather normalized volumes compared to the 2013 weather normalized volumes. The scaling factors used to estimate the 2018 demand data for the 2018 cost allocation model are shown below in Table 7-5.

Table 7-5 Load Profiling Scaling Factors

Rate Class	2013 Weather Normal Values (kWh)	2018 Weather Normal Values (kWh)	Scaling Factor
Residential	340,561,449	296,393,596	87.0%
General Service < 50 kW	102,179,766	94,320,130	92.3%
General Service 50 to 4,999 kW	251,632,820	248,349,153	98.7%
Sentinel Lighting	254,165	218,403	85.9%
Street Lights	7,907,160	2,415,793	30.6%
Unmetered Scattered Load	872,889	1,176,822	134.8%
Total	703,408,249	642,873,897	91.4%

The allocated cost by rate class for the 2013 Cost of Service filing and the 2018 updated study are provided in the following Table 7-6.

Table 7-6: Allocated Cost –
(Consistent with RRWF, Tab 11 Cost Allocation, Allocated Costs)

Rate Class	2013 Board Approved Cost Allocation Study	%	2018 Cost Allocation Study	%
Residential	$11,580,870	61.5%	$14,193,143	64.3%
General Service < 50 kW	$2,673,048	14.2%	$3,048,990	13.8%
General Service 50 to 4,999 kW	$3,475,269	18.4%	$4,543,021	20.6%
Sentinel Lighting	$45,301	0.2%	$46,411	0.2%
Street Lights	$1,033,492	5.5%	$204,002	0.9%
Unmetered Scattered Load	$33,369	0.2%	$45,677	0.2%
Total	$18,841,349	100.0%	$22,081,245	100.0%

PUC Distribution is not proposing an Embedded Distributor rate class (PUC Distribution is not a host to any other distributor), Standby Rates (PUC Distribution will await the OEB's new rate policy for commercial customers, once implemented), or a Large Use Class (no customers are forecasted for this class in the test year).

Unmetered Loads

PUC Distribution communicates with unmetered load customers, including Street Lighting customers, to assist them in understanding the regulatory context in which distributors operate and how it affects unmetered load customers. This communication takes place on an on-going basis and is not driven by the rate application process.

microFIT Class

PUC Distribution is not proposing to include microFIT as a separate class in the cost allocation model in 2018. PUC Distribution understands that the cost allocation model will produce a calculation of unit costs which the OEB will use to update the uniform microFIT rate at a future date.

2.7.1.1 New Customer Class

PUC Distribution is not proposing to include a new customer class.

2.7.1.2 Eliminated Customer Class

PUC Distribution is not proposing to eliminate a rate class.

2.7.2 Class Revenue Requirements

The following Table 7-7 provides information on calculated class revenue. The resulting 2018 proposed base revenue will be the amount used in Exhibit 8 to design the proposed distribution charges in this application.

Table 7-7 Calculated Class Revenue –
(Consistent with RRWF, Tab 11 Cost Allocation, Calculated Class Revenues)

Rate Class	2018 Base Revenue at Existing Rates	2018 Proposed Base Revenue Allocated at Existing Rates Proportion	2018 Proposed Base Revenue	Miscellaneous Revenue
Residential	$9,084,381	$11,172,059	$11,487,469	$1,567,716
General Service < 50 kW	$2,640,479	$3,247,287	$3,247,287	$323,010
General Service 50 to 4,999 kW	$3,797,584	$4,670,305	$4,670,305	$441,680
Sentinel Lighting	$29,086	$35,771	$35,771	$8,392
Street Lights	$420,382	$516,990	$203,298	$41,505
Unmetered Scattered Load	$39,984	$49,173	$47,454	$7,358
Total	$16,011,897	$19,691,584	$19,691,584	$2,389,661

2.7.3 Revenue-to-Cost Ratios

The results of a cost allocation study are typically presented in the form of revenue to cost ratios. The ratio is shown by rate classification and is the percentage of distribution revenue collected by rate classification compared to the costs allocated to the classification. The percentage identifies the rate classifications that are being subsidized and those that are over-contributing. A percentage of less than 100% means the rate classification is under-contributing and is being subsidized by other classes of customers. A percentage of greater than 100% indicates the rate classification is over-contributing and is subsidizing other classes of customers.

In the March Board Report, the Board established what it considered to be the appropriate ranges of revenue to cost ratios which are summarized in Table 7-8 below. In addition, Table 7-8 provides PUC Distribution’s revenue to cost ratios from the 2013 application, the updated 2018 cost allocation study and the proposed 2018 to 2020 ratios.

Table 7-8 Revenue to Cost Ratios – (Consistent with RRWF, Tab 11 Cost Allocation, Proposed & Rebalancing Revenue to Cost Ratios)

Rate Class	2013 Board Approved Cost Allocation Study	2018 Cost Allocation Study	2018 Proposed Ratios	2019 & 2020 Ratios	OEB Targets Min to Max	
Residential	92.7%	89.8%	92.0%	92.0%	85.0%	115.0%
General Service < 50 kW	113.4%	117.1%	117.1%	117.1%	80.0%	120.0%
General Service 50 to 4,999 kW	119.5%	112.5%	112.5%	112.5%	80.0%	120.0%
Sentinel Lighting	83.0%	95.2%	95.2%	95.2%	80.0%	120.0%
Street Lights	82.3%	273.8%	120.0%	120.0%	80.0%	120.0%
Unmetered Scattered Load	100.1%	123.8%	120.0%	120.0%	80.0%	120.0%

The 2018 cost allocation study indicates the revenue to cost ratios for the Street Lighting and Unmetered Scattered Load rate classes are outside the OEB’s range. For 2018 and onward, it is proposed the ratios for the Street Lighting and Unmetered Scattered Load rate classes be brought within the OEB’s range. The Residential class will be adjusted upward to maintain revenue neutrality.

APPENDIX 1

Input Sheets I-6 & I-8
Output Sheets O-1 & O-2 (first page only).

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Sheet I6.1 Revenue Worksheet -

Total kWhs from Load Forecast	642,873,897
Total kWs from Load Forecast	632,192
Deficiency/sufficiency (RRWF 8. cell F52)	- 3,679,687
Miscellaneous Revenue (RRWF 5. cell F48)	2,389,661

			1	**2**	**3**	**7**	**8**	**9**
	ID	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
Billing Data								
Forecast kWh	**CEN**	642,873,897	296,393,596	94,320,130	248,349,153	2,415,793	218,403	1,176,822
Forecast kW	**CDEM**	632,192			624,500	7,076	616	
Forecast kW, included in CDEM, of customers receiving line transformer allowance		138,000			138,000			
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-						
KWh excluding KWh from Wholesale Market Participants	**CEN EWMP**	642,873,897	296,393,596	94,320,130	248,349,153	2,415,793	218,403	1,176,822

Existing Monthly Charge			$16.79	$17.11	$114.46	$2.94	$2.93	$12.69
Existing Distribution kWh Rate			$0.0104	$0.0205				$0.0310
Existing Distribution kW Rate					$5.4372	$19.1736	$27.3551	
Existing TOA Rate					$0.60			
Additional Charges								
Distribution Revenue from Rates		$16,094,697	$9,084,381	$2,640,479	$3,880,384	$420,382	$29,086	$39,984
Transformer Ownership Allowance		$82,800	$0	$0	$82,800	$0	$0	$0
Net Class Revenue	**CREV**	$16,011,897	$9,084,381	$2,640,479	$3,797,584	$420,382	$29,086	$39,984

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Sheet I6.2 Customer Data Worksheet -

			1	2	3	7	8	9
	ID	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Billing Data								
Bad Debt 3 Year Historical Average	BDHA	$303,205	$229,262	$43,267	$30,676	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$257,333	$189,877	$36,868	$30,588			
Number of Bills	CNB	1,475,760	357,468	41,316	4,236	48	12	276
Number of Devices	CDEV					9,314		
Number of Connections (Unmetered)	CCON	8,713				8,070	348	295
Total Number of Customers	CCA	33,613	29,789	3,443	353	4	1	23
Bulk Customer Base	CCB	-						
Primary Customer Base	CCP	33,878	29,789	3,443	353	269	1	23
Line Transformer Customer Base	CCLT	33,833	29,789	3,438	313	269	1	23
Secondary Customer Base	CCS	32,856	29,789	2,906	133	4	1	23
Weighted - Services	CWCS	32,257	29,789	1,976	56	404	17	15
Weighted Meter -Capital	CWMC	8,482,904	6,106,745	2,021,041	355,118	-	-	-
Weighted Meter Reading	CWMR	40,225	29,789	3,443	6,993	-	-	-
Weighted Bills	CWNB	420,701	357,468	45,861	17,113	37	9	213

Bad Debt Data

Historic Year:	2015	181,140	136,965	25,848	18,327			
Historic Year:	2016	378,475	286,175	54,008	38,291			
Bridge Year:	2017	350,000	264,645	49,944	35,411			
Three-year average		**303,205**	**229,262**	**43,267**	**30,676**	**-**	**-**	**-**

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Sheet I8 Demand Data Worksheet -

This is an input sheet for demand allocators.

CP TEST RESULTS	4 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

			1	2	3	7	8	9
Customer Classes		Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
		CP Sanity Check	Pass	Pass	Check 4CP	Check 4CP and 12CP	Check 4CP and 12CP	Check 4CP and 12CP
CO-INCIDENT PEAK								
1 CP								
Transformation CP	TCP1	130,045	71,461	20,180	38,271			133
Bulk Delivery CP	BCP1	130,045	71,461	20,180	38,271			133
Total Sytem CP	DCP1	130,045	71,461	20,180	38,271			133
4 CP								
Transformation CP	TCP4	497,642	267,266	67,776	160,347	1,577	131	545
Bulk Delivery CP	BCP4	497,642	267,266	67,776	160,347	1,577	131	545
Total Sytem CP	DCP4	497,642	267,266	67,776	160,347	1,577	131	545
12 CP								
Transformation CP	TCP12	1,228,789	610,928	175,873	437,014	3,087	278	1,608
Bulk Delivery CP	BCP12	1,228,789	610,928	175,873	437,014	3,087	278	1,608
Total Sytem CP	DCP12	1,228,789	610,928	175,873	437,014	3,087	278	1,608
NON CO_INCIDENT PEAK								
		NCP Sanity Check	Pass	Pass	Pass	Pass	Pass	Pass
1 NCP								
Classification NCP from Load Data Provider	DNCP1	140,280	74,085	22,170	43,132	653	98	141
Primary NCP	PNCP1	140,280	74,085	22,170	43,132	653	98	141
Line Transformer NCP	LTNCP1	135,921	74,085	22,126	38,819	653	98	141
Secondary NCP	SNCP1	108,576	74,085	18,933	14,665	653	98	141
4 NCP								
Classification NCP from Load Data Provider	DNCP4	536,073	280,089	83,525	169,029	2,525	357	548
Primary NCP	PNCP4	536,073	280,089	83,525	169,029	2,525	357	548
Line Transformer NCP	LTNCP4	519,003	280,089	83,357	152,126	2,525	357	548
Secondary NCP	SNCP4	412,319	280,089	71,330	57,470	2,525	357	548
							357	
12 NCP								
Classification NCP from Load Data Provider	DNCP12	1,337,868	643,526	215,097	469,459	7,357	820	1,608
Primary NCP	PNCP12	1,337,868	643,526	215,097	469,459	7,357	820	1,608
Line Transformer NCP	LTNCP12	1,290,492	643,526	214,667	422,514	7,357	820	1,608
Secondary NCP	SNCP12	996,621	643,526	183,693	159,616	7,357	820	1,608

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Sheet O1 Revenue to Cost Summary Worksheet -

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	7	8	9
Rate Base Assets		**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
crev	Distribution Revenue at Existing Rates	$16,011,897	$9,084,381	$2,640,479	$3,797,584	$420,382	$29,086	$39,984
mi	Miscellaneous Revenue (mi)	$2,389,661	$1,567,716	$323,010	$441,680	$41,505	$8,392	$7,358
		Miscellaneous Revenue Input equals Output						
	Total Revenue at Existing Rates	$18,401,558	$10,652,097	$2,963,489	$4,239,264	$461,887	$37,479	$47,342
	Factor required to recover deficiency (1 + D)	1.2298						
	Distribution Revenue at Status Quo Rates	$19,691,584	$11,172,059	$3,247,287	$4,670,305	$516,990	$35,771	$49,173
	Miscellaneous Revenue (mi)	$2,389,661	$1,567,716	$323,010	$441,680	$41,505	$8,392	$7,358
	Total Revenue at Status Quo Rates	$22,081,245	$12,739,775	$3,570,297	$5,111,985	$558,494	$44,163	$56,531
	Expenses							
di	Distribution Costs (di)	$5,575,886	$3,471,594	$751,678	$1,271,699	$50,649	$15,538	$14,727
cu	Customer Related Costs (cu)	$2,212,119	$1,726,781	$294,810	$152,883	$34,424	$1,501	$1,720
ad	General and Administration (ad)	$4,167,828	$2,772,669	$560,788	$771,444	$44,974	$9,130	$8,822
dep	Depreciation and Amortization (dep)	$3,783,956	$2,335,532	$562,494	$844,521	$27,278	$7,041	$7,090
INPUT	PILs (INPUT)	$366,429	$224,578	$50,804	$86,818	$2,697	$763	$770
INT	Interest	$2,389,294	$1,464,356	$331,267	$566,093	$17,587	$4,974	$5,018
	Total Expenses	$18,495,512	$11,995,511	$2,551,841	$3,693,458	$177,609	$38,947	$38,147
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$3,585,733	$2,197,632	$497,149	$849,563	$26,393	$7,464	$7,530
	Revenue Requirement (includes NI)	$22,081,245	$14,193,143	$3,048,990	$4,543,021	$204,002	$46,411	$45,677
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$121,216,039	$74,707,272	$16,963,187	$28,041,387	$960,378	$274,381	$269,435
gp	General Plant - Gross	$1,604,890	$988,800	$222,377	$373,585	$12,792	$3,704	$3,632
accum dep	Accumulated Depreciation	($15,769,425)	($9,700,867)	($2,353,608)	($3,545,383)	($112,469)	($28,271)	($28,827)
co	Capital Contribution	($14,333,603)	($9,168,323)	($1,976,988)	($2,904,255)	($177,910)	($56,682)	($49,444)
	Total Net Plant	$92,717,901	$56,826,883	$12,854,968	$21,965,334	$682,790	$193,131	$194,795
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$79,854,870	$36,828,093	$11,714,885	$30,838,659	$299,980	$27,120	$146,131
	OM&A Expenses	$11,955,833	$7,971,045	$1,607,276	$2,196,026	$130,047	$26,169	$25,270
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$91,810,703*	*$44,799,138*	*$13,322,161*	*$33,034,686*	*$430,027*	*$53,289*	*$171,401*
	Working Capital	$6,885,803	$3,359,935	$999,162	$2,477,601	$32,252	$3,997	$12,855
	Total Rate Base	$99,603,704	$60,186,818	$13,854,130	$24,442,935	$715,042	$197,128	$207,650
		Rate Base Input equals Output						
	Equity Component of Rate Base	$39,841,481	$24,074,727	$5,541,652	$9,777,174	$286,017	$78,851	$83,060
	Net Income on Allocated Assets	$3,585,733	$744,264	$1,018,456	$1,418,527	$380,885	$5,217	$18,384
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0

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Sheet O1 Revenue to Cost Summary Worksheet -

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	7	8	9
Rate Base Assets		**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
	Net Income	$3,585,733	$744,264	$1,018,456	$1,418,527	$380,885	$5,217	$18,384
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES STATUS QUO%	100.00%	89.76%	117.10%	112.52%	273.77%	95.16%	123.76%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($3,679,687)	($3,541,046)	($85,501)	($303,757)	$257,884	($8,932)	$1,665
			Deficiency Input equals Output					
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	($1,453,368)	$521,306	$568,964	$354,492	($2,248)	$10,854
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.00%	3.09%	18.38%	14.51%	133.17%	6.62%	22.13%

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Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	7	8	9
	Residential	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
Customer Unit Cost per month - Avoided Cost	$5.00	$8.99	$27.92	$0.35	$0.35	$0.47
Customer Unit Cost per month - Directly Related	$7.32	$12.42	$44.35	$0.54	$0.54	$0.73
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$19.00	$23.51	$62.31	$1.55	$10.73	$8.68
Existing Approved Fixed Charge	$16.79	$17.11	$114.46	$2.94	$2.93	$12.69

PUC Distribution Inc.
EB-2017-0071
Filed: March 29, 2018

EXHIBIT 8:
RATE DESIGN

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APPENDIX 1 Retail Transmission Service Rate Work Form

APPENDIX 2 Current Tariff of Rates

APPENDIX 3 Proposed Tariff of Rates

Exhibit 8: Rate Design

This Exhibit documents the calculation of PUC Distribution's proposed distribution rates by rate class for the PUC Distribution test year, based on the rate design as proposed in this Exhibit.

PUC Distribution has determined its total PUC Distribution service revenue requirement to be $22,081,244. The total revenue offsets in the amount of $2,389,661 reduces PUC Distribution's total service revenue requirement to a base revenue requirement of $19,691,584 which is used to determine the proposed distribution rates. The base revenue requirement is derived from PUC Distribution's capital and operating forecasts, weather normalized usage, forecasted customer counts, and regulated return on rate base. The revenue requirement is summarized in Table 8-1 below:

Table 8-1 Calculation of Base Revenue Requirement

Description	Amount
OM&A Expenses	$11,955,833
Amortization Expenses	$3,783,956
Regulated Return On Capital	$5,975,027
PILs	$366,429
Service Revenue Requirement	**$22,081,244**
Less Revenue Offsets	$2,389,661
Base Revenue Requirement	**$19,691,584**

The outstanding base revenue requirement is allocated to the various rate classes as outlined in Exhibit 7 – Cost Allocation, Table 7-8. The following Table 8-2 outlines the allocation of the base revenue requirement to the rate classes.

Table 8-2 Proposed Apportionment of Base Revenue to Rate Classes

Rate Class	**2018 Proposed Base Revenue Requirement**
Residential	$11,487,469
General Service < 50 kW	$3,247,287
General Service 50 to 4,999 kW	$4,670,305
Sentinel Lighting	$35,771
Street Lighting	$203,298
Unmetered Scattered Load	$47,454
Total	**$19,691,584**

2.8.1 Fixed/Variable Proportion

Current Fixed / Variable Proportion

Based on applying the existing approved monthly service charges to the forecasted number of customers for PUC Distribution along with the existing approved distribution volumetric charge, excluding rate riders, and the transformer allowance, to the PUC Distribution forecasted volumes, the following Table 8-3 outlines PUC Distribution’s current split between fixed and variable distribution revenue.

Table 8-3 Current Fixed Variable Split

Rate Class	**2018 Fixed Base Revenue with 2017 Approved Rates**	**2018 Variable Base Revenue with 2017 Approved Rates**	**2018 Total Base Revenue with 2017 Approved Rates**	**Fixed Revenue Proportion**	**Variable Revenue Proportion**
Residential	$6,001,888	$3,082,493	$9,084,381	66.1%	33.9%
General Service < 50 kW	$706,917	$1,933,563	$2,640,479	26.8%	73.2%
General Service 50 to 4,999 kW	$484,853	$3,312,731	$3,797,584	12.8%	87.2%
Sentinel Lighting	$12,236	$16,851	$29,086	42.1%	57.9%
Street Lighting	$284,710	$135,672	$420,382	67.7%	32.3%
Unmetered Scattered Load	$3,502	$36,481	$39,984	8.8%	91.2%
Total	**$7,494,105**	**$8,517,792**	**$16,011,897**	**46.8%**	**53.2%**

Proposed Monthly Service Charge

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. This proposal is consistent with the Ontario Energy Board's ("Board") Decision in the following cases:

a) InnPower Corporation – 2017 Cost of Service Application (EB-2016-0085)

b) Centre Wellington Hydro Ltd. - 2013 Cost of Service Rate (*EB-2012-0113*);

c) Atikokan Hydro Inc. - 2012 Cost of Service Rate (*EB-2011-0293*);

d) Espanola Regional Hydro Distribution Corporation - 2012 Cost of Service Rate (*EB-2011-0319*);

e) Horizon Utilities Corporation - 2011 Cost of Service Application (*EB-2010-0131*);

f) Hydro One Brampton Networks Inc. - 2011 Cost of Service Application (*EB-2010-0132*);

g) Kenora Hydro Electric Corporation Ltd. - 2011 Cost of Service Application (*EB-2010-0135*); and.

h) In Horizon Utilities Corporation's ("Horizon") decision on their 2015 rates (EB-2014-0002) the Board approved Horizon's proposal to maintain the fixed/variable split. The following outlines the Board findings with regards to proposed fixed/variable split.

> *The Board accepts Horizon's proposal. While the Board's current policy direction is to move toward an increased fixed charge, this consideration was not the sole basis upon which the Board reached its Decision. The Settlement Agreement contains a re-opener provision which would address any policy change related to an increased fixed charge.*
>
> *A fixed/variable split above the ceiling was approved in Horizon's last cost of service proceeding. In this application, Horizon has maintained the fixed/variable split.*
>
> *The Board notes that a principle of rate design is that in most circumstances rate stability is desirable. Counter-direction in rates can be confusing to ratepayers. Horizon has chosen to maintain a fixed/variable split that moves above the ceiling. Intervenors argue that this is contrary to the Board's report in EB-2007-0667.*

On April 2, 2015, the Board released its Board Policy: A New Distribution Rate Design for Residential Electricity Customers (EB-2012-0410). On page 9 of that policy it states

> *"The current rate design for distribution service is not reflective of the costs to distribute electricity, because costs that are mostly fixed are being recovered through charges which vary with usage."*

Based on the above statement it is PUC Distribution's proposal that it would be reasonable to maintain the current fixed/variable split for all rate classes, except Residential, and not move a higher proportion of costs to the usage rate.

2.8.2 Rate Design Policy

In regards to the Residential class, the Board's policy referenced above states 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 Board 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. In proposing a transition to a fully fixed monthly service charge, PUC Distribution has followed the approach set out in Tab 12 of the RRWF and the resulting Residential monthly fixed charge is provided in the table below.

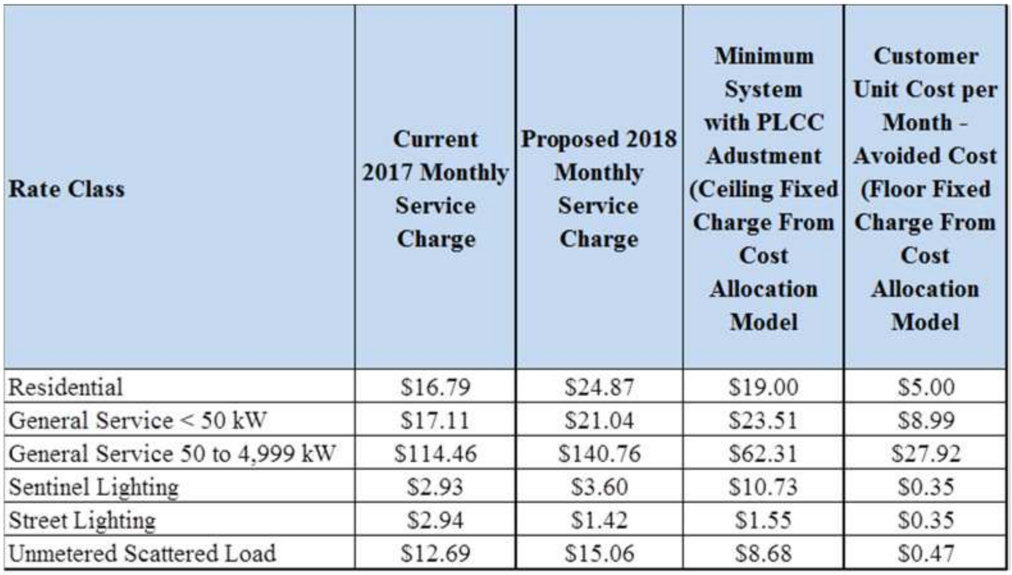
The following Table 8-4 outlines the proposed monthly service charge by rate class for PUC Distribution.

Table 8-4 Proposed Monthly Service Charge

Rate Class	Total Base Revenue Requirement	Fixed Revenue Proportion	Fixed Revenue	Annualized Customers / Connections	Proposed Monthly Service Charge
Residential	$11,487,469	77.4%	$8,890,229	357,468	$24.87
General Service < 50 kW	$3,247,287	26.8%	$869,373	41,316	$21.04
General Service 50 to 4,999 kW	$4,670,305	12.8%	$596,276	4,236	$140.76
Sentinel Lighting	$35,771	42.1%	$15,048	4,176	$3.60
Street Lighting	$203,298	67.7%	$137,687	96,840	$1.42
Unmetered Scattered Load	$47,454	8.8%	$4,157	276	$15.06
Total	**$19,691,584**		**$10,512,769**	**504,312**	

For comparison purposes, the following Table 8-5 provides the current and proposed monthly service charge by rate class as well as monthly service charge information from the cost allocation model.

Table 8-5 Monthly Service Charge Comparison



Rate Class	Current 2017 Monthly Service Charge	Proposed 2018 Monthly Service Charge	Minimum System with PLCC Adustment (Ceiling Fixed Charge From Cost Allocation Model	Customer Unit Cost per Month - Avoided Cost (Floor Fixed Charge From Cost Allocation Model
Residential	$16.79	$24.87	$19.00	$5.00
General Service < 50 kW	$17.11	$21.04	$23.51	$8.99
General Service 50 to 4,999 kW	$114.46	$140.76	$62.31	$27.92
Sentinel Lighting	$2.93	$3.60	$10.73	$0.35
Street Lighting	$2.94	$1.42	$1.55	$0.35
Unmetered Scattered Load	$12.69	$15.06	$8.68	$0.47

Proposed Volumetric Charges

The variable distribution charge is calculated by dividing the variable distribution portion of the base revenue requirement by the appropriate PUC Distribution Test Year usage, kWh or kW, as the class charge determinant.

The following Table 8-6 provides PUC Distribution's calculations of its proposed variable distribution charges for the PUC Distribution Test Year which maintains the same fixed/variable split used in designing the current approved rates.

Table 8-6 Proposed Distribution Volumetric Charge

Rate Class	Total Base Revenue Requirement	Variable Revenue Proportion	Variable Revenue	Annualized kWh or kW as required	Unit of Measure	Proposed Distribution Volumtric Charge before Transformer Allowance
Residential	$11,487,469	22.6%	$2,597,239	296,393,596	kWh	$0.0088
General Service < 50 kW	$3,247,287	73.2%	$2,377,914	94,320,130	kWh	$0.0252
General Service 50 to 4,999 kW	$4,670,305	87.2%	$4,074,029	624,500	kW	$6.5237
Sentinel Lighting	$35,771	57.9%	$20,723	616	kW	$33.6416
Street Lighting	$203,298	32.3%	$65,612	7,076	kW	$9.2724
Unmetered Scattered Load	$47,454	91.2%	$43,297	1,176,822	kWh	$0.0368
Total	**$19,691,584**		**$9,178,814**			

Proposed Adjustment for Transformer Allowance

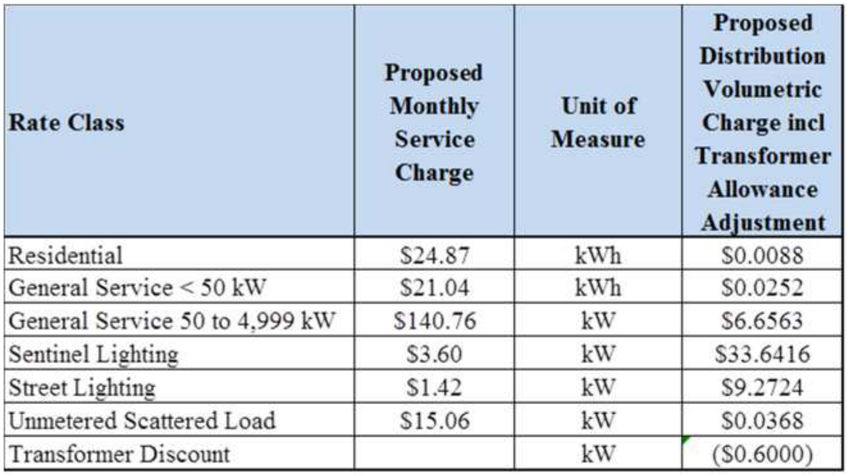
Currently, PUC Distribution provides a transformer allowance to those customers that own their transformation facilities. PUC Distribution proposes to maintain the current approved transformer ownership allowance of $0.60 per kW ("Transformer Allowance"). The Transformer Allowance is intended to reflect the costs to a distributor of providing step down transformation facilities to the customer's utilization voltage level. Since the distributor provides electricity at utilization voltage, the cost of this transformation is captured in and recovered through the distribution rates. Therefore, when a customer provides its own step down transformation from primary to secondary, it should receive a credit of these costs already included in the distribution rates.

The amount of Transformer Allowance expected to be provided to the customers in the General Service 50 to 4,999 kW class that owns their transformers has been included in the volumetric charge for this class. This means the General Service 50 to 4,999 kW volumetric charge of $6.5237 per kW will increase by $0.1326 per kW to a total of $6.6563 per kW to recover the amount of the Transformer Allowance over all kWs in the General Service 50 to 4,999 kW class.

Proposed Distribution Rates

The following Table 8-7 sets out PUC Distribution's proposed electricity distribution rates based on the foregoing calculations, including adjustments for the recovery of transformer allowance.

Table 8-7 Proposed Distribution Rates



Rate Class	Proposed Monthly Service Charge	Unit of Measure	Proposed Distribution Volumetric Charge incl Transformer Allowance Adjustment
Residential	$24.87	kWh	$0.0088
General Service < 50 kW	$21.04	kWh	$0.0252
General Service 50 to 4,999 kW	$140.76	kW	$6.6563
Sentinel Lighting	$3.60	kW	$33.6416
Street Lighting	$1.42	kW	$9.2724
Unmetered Scattered Load	$15.06	kW	$0.0368
Transformer Discount		kW	($0.6000)

2.8.3 Retail Transmission Service Rates

PUC Distribution receives wholesale transmission service from metered points that are directly connected to the grid. PUC Distribution is billed Uniform Transmission Rates by the IESO on all capacity delivered through these points. PUC Distribution passes these charges unto their customers with Board approved Retail Transmission Service Rates (RTSR). In order to determine the RTSR, PUC Distribution has completed the 2018_RTSR_Workform and it has been filed as part of this application. The RTSR information is also consistent with the Working Capital Allowance calculation. The RTSR Workform is also provided in Appendix 8-A in PDF format. Table 8-8 provides the RTSR rates generated from the PUC Distribution 2018_RTSR_Workform.

Table 8-8 Proposed Retail Transmission Rates

	Retail Transmission Network Rates	
Rate Class	**Per kWh**	**Per kW**
Residential	$0.0062	
General Service < 50 kW	$0.0058	
General Service 50 to 4,999 kW		$2.3597
General Service 50 to 4,999 kW Interval		$2.9676
Sentinel Lighting		$1.7887
Street Lighting		$1.7796
Unmetered Scattered Load	$0.0058	

2.8.4 Retail Service Charges

PUC Distribution is not proposing any changes to the retail service charges in this application

2.8.5 Regulatory Charges

On December 15, 2016 the Board issued a Decision with Reasons and Rate Order (EB-2016-0362) establishing that the Wholesale Market Service used by rate-regulated distributors to bill their customers shall be $0.0032 per kilowatt-hour, effective January 1, 2017. For Class B customers a CBR component of $0.0004 per kilowatt-hour shall be added to the WMS rate for a total of $0.0036 per kilowatt-hour. For Class A customers, distributors shall bill the actual CBR costs to Class A customers in proportion to their contribution to peak.

On June 22, 2017 the Board issued a Decision with Reasons and Rate Order (EB-2017-0234) establishing that the RRRP charge used by rate-regulated distributors to bill their customers shall be $0.0003 per kilowatt-hour for electricity consumed on or after July 1, 2017. This unit rate shall apply to a customer’s metered energy consumption adjusted by the distributor’s Board-approved Total Loss Factor.

On March 1, 2018, the Board issued a Decision and Order (EB-2017-0290) establishing a Smart Metering Entity Charge of $0.57 per month for Residential and General Service < 50kW customers effective January 1, 2018 to December 31, 2022. PUC Distribution has reflected a Smart Metering Entity Charge of $0.57 per month in this Application.

2.8.6 Low Voltage Service Rates

Low Voltage Service Rates are not applicable in this Application.

2.8.7 Specific Service Charges

PUC Distribution is proposing the current specific service charges be maintained in this application.

2.8.8 Loss Adjustment Factors

PUC Distribution has calculated the total loss factor to be applied to customers' consumption based on the average wholesale and retail kWh for the years 2012 to 2016. The calculations are summarized in the following Table 8-10 which also consistent with calculations provided in Appendix 2-R. PUC Distribution is not an embedded distributor.

Table 8-9 Loss Factor Calculation

		Historical Years					5-Year Average
		2012	**2013**	**2014**	**2015**	**2016**	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	706,953,513	730,568,311	730,490,285	698,517,377	669,958,462	707,297,590
A(2)	"Wholesale" kWh delivered to distributor (lower value)	706,953,513	730,568,311	730,490,285	698,517,377	669,958,462	707,297,590
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)						-
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	706,953,513	730,568,311	730,490,285	698,517,377	669,958,462	707,297,590
D	"Retail" kWh delivered by distributor	676,765,709	688,834,667	701,843,127	669,387,526	637,462,404	674,858,687
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)						-
F	Net "Retail" kWh delivered by	676,765,709	688,834,667	701,843,127	669,387,526	637,462,404	674,858,687
G	Loss Factor in Distributor's system = **C / F**	1.0446	1.0606	1.0408	1.0435	1.0510	1.0481
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
	Total Losses						
I	Total Loss Factor = **G x H**	1.0446	1.0606	1.0408	1.0435	1.0510	1.0481

The following Table 8-12 provides the total loss factor for secondary and primary customers:

Table 8-10 Total Loss Factor

Total Loss Factors	
Supply Facility Loss Factor	**1.0000**
Distribution Loss Factor	
Distribution Loss Factor - Secondary Metered Customer < 5,000kW	**1.0481**
Distribution Loss Factor - Primary Metered Customer < 5,000kW	**1.0376**
Total Loss Factor	
Total Loss Factor - Secondary Metered Customer < 5,000kW	**1.0481**
Total Loss Factor - Primary Metered Customer < 5,000kW	**1.0376**

Materiality Analysis on Distribution Losses

PUC Distribution's distribution 5-year average Loss Adjustment factor is 4.81%. Pursuant to the Filing Requirements, as the Distribution Loss Adjustment factor is less than 5%, PUC Distribution is not required to provide an explanation of, or justification for, its loss adjustment factor.

2.8.9 Tariff of Rates and Charges

The current and proposed tariff of rates and charges are provided below. There current definition of rate classes and the current terms and conditions of service has been maintained in this application.

For the current tariff of rates and charges from the current approved rate order for PUC Distribution dated March 30, 2017 (EB-2016-0102), please see Appendix 8-B.

For the proposed tariff of rates and charges please see tab 4. 2-TS Tariff Schedule from the following live Excel file "2018_Tariff_Schedule_and_Bill_Impact_Model" and see Appendix 8-C.

2.8.10 Revenue Reconciliation

The following table provides reconciliation between the revenue based on the PUC Distribution proposed distribution rates and the total base revenue requirement. The calculation of revenue under current rates is provided in Table 3-1 at section 2.3.1 of Exhibit 3.

Table 8-11 PUC Distribution Test Year Distribution Revenue Reconciliation

Rate Class	Customers/ Connections	Number of Customers/ Connections	Test Year Consumption		Proposed Rates			Revenues at Proposed Rates
		Average	kWh	kW	Monthly Service Charge	Volumetric		
						kWh	kW	
Residential	Customers	29,789	296,393,596		$ 24.87	$ 0.0088		$ 11,498,493
General Service < 50 kW	Customers	3,443	94,320,130		$ 21.04	$ 0.0252		$ 3,246,156
General Service 50 to 4,999 kW	Customers	353		624,500	$ 140.76		$ 6.6563	$ 4,753,119
Sentinel Lighting	Connections	348		616	$ 3.60		$ 33.6416	$ 35,757
Street Lighting	Connections	8,070		7,076	$ 1.42		$ 9.2724	$ 203,124
Unmetered Scattered Load	Customers	23	1,176,822		$ 15.06	$ 0.0368		$ 47,464
Total								$ 19,784,112

Class Specific Revenue Requirement	Transformer Allowance Credit	Total	Difference
$ 11,487,469		$ 11,487,469	-$ 11,024
$ 3,247,287		$ 3,247,287	$ 1,131
$ 4,670,305	$ 82,800	$ 4,753,105	-$ 14
35,771		$ 35,771	$ 14
$ 203,298		$ 203,298	$ 174
$ 47,454		$ 47,454	-$ 9
$ 19,691,584	$ 82,800	$ 19,774,384	-$ 9,728

2.8.11 Bill Impact Information

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 Board 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 impact referenced above. 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.

Appendix 8-D to this Exhibit presents the results of the assessment of customer total bill impacts by level of consumption by rate class. Appendix 8-D is consistent with tab 5. 2-W Bill Impacts from the following live Excel file “2018_Tariff_Schedule_and_Bill_Impact_Model”

Impacts are shown using the applicable current approved rates and the proposed PUC Distribution rates for distribution, including Rate Riders for the recovery of Deferral and Variance accounts discussed in Exhibit 9.

The rate impacts are assessed on the basis of moving to the proposed distribution rates.

2.8.12 Rate Mitigation

PUC Distribution submits that the bill impacts of its proposed electricity distribution rates are reasonable and do not require rate mitigation. PUC Distribution confirms that it is not increasing its monthly service charge by more than $4.00 due only to a rate design change. Refer to Tab 12 of the Revenue Requirement Workform, Residential Rate Design, line 53, which shows the change in rate to be $3.64.

APPENDIX 1

Retail Transmission Service Rate Work Form

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2018 RTSR Workform for Electricity Distributors

Drop-down lists are shaded blue; Input cells are shaded green.

Utility Name	PUC Distribution Inc.
Service Territory	Sault Ste. Marie, Ontario
Assigned EB Number	EB-2017-0071
Name and Title	Andrew Belsito, Rates and Regulatory Affairs Officer
Phone Number	705-759-3009
Email Address	andrew.belsito@ssmpuc.com
Date	1-Mar-18
Last COS Re-based Year	**2012**

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

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2018 RTSR Workform
for Electricity Distributors

1. Select the appropriate rate classes that appear on your most recent Board-Approved Tariff of Rates and Charges.
2. Enter the RTS Network and Connection Rate as it appears on the Tariff of Rates and Charges

Rate Class	Unit	RTSR-Network	RTSR-Connection
Residential	kWh	0.0059	
General Service Less Than 50 kW	kWh	0.0055	
General Service 50 to 4,999 kW	kW	2.2455	
General Service 50 to 4,999 kW – Interval Metered	kW	2.8240	
Unmetered Scattered Load	kWh	0.0055	
Sentinel Lighting	kW	1.7021	
Street Lighting	kW	1.6935	
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
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Choose Rate Class			

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2018 RTSR Workform for Electricity Distributors

Rate Class	Rate Description	Unit	Rate	Non-Loss Adjusted Metered kWh	Non-Loss Adjusted Metered kW	Applicable Loss Factor *eg: (1.0325)*	Loss Adjusted Billed kWh
Residential	RTSR - Network	kWh	0.0059	288,746,486		1.0489	302,866,189
Residential	RTSR - Connection	kWh					0
General Service Less Than 50 kW	RTSR - Network	kWh	0.0055	92,174,996		1.0489	96,682,353
General Service Less Than 50 kW	RTSR - Connection	kWh					0
General Service 50 to 4,999 kW	RTSR - Network	kW	2.2455	159,591,245	418,637		
General Service 50 to 4,999 kW	RTSR - Connection	kW					
General Service 50 to 4,999 kW – Interval Metered	RTSR - Network	kW	2.8240	90,363,934	203,435		
General Service 50 to 4,999 kW – Interval Metered	RTSR - Connection	kW					
Unmetered Scattered Load	RTSR - Network	kWh	0.0055	1,489,410		1.0489	1,562,242
Unmetered Scattered Load	RTSR - Connection	kWh					0
Sentinel Lighting	RTSR - Network	kW	1.7021	227,056	630		
Sentinel Lighting	RTSR - Connection	kW					
Street Lighting	RTSR - Network	kW	1.6935	4,869,277	14,262		
Street Lighting	RTSR - Connection	kW					

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2018 RTSR Workform for Electricity Distributors

Uniform Transmission Rates	Unit	2016	2017	2018
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 3.66	$ 3.66	$ 3.66
Line Connection Service Rate	kW	$ 0.87	$ 0.87	$ 0.87
Transformation Connection Service Rate	kW	$ 2.02	$ 2.02	$ 2.02

Hydro One Sub-Transmission Rates	Unit	2016		2017	2018
		Jan 2016	Feb - Dec 2016		
Rate Description		**Rate**		**Rate**	**Rate**
Network Service Rate	kW	$ 3.4121	$ 3.3396	$ 3.1942	
Line Connection Service Rate	kW	$ 0.7879	$ 0.7791	$ 0.7710	
Transformation Connection Service Rate	kW	$ 1.8018	$ 1.7713	$ 1.7493	
Both Line and Transformation Connection Service Rate	kW	$ 2.5897	$ 2.5504	$ 2.5203	$ -

If needed, add extra host here. (I)	Unit	2016	2017	2018
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW			
Line Connection Service Rate	kW			
Transformation Connection Service Rate	kW			
Both Line and Transformation Connection Service Rate	kW	$ -	$ -	$ -

If needed, add extra host here. (II)	Unit	Effective January 1, 2016	Effective January 1, 2017	Effective January 1, 2018
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW			
Line Connection Service Rate	kW			
Transformation Connection Service Rate	kW			
Both Line and Transformation Connection Service Rate	kW	$ -	$ -	$ -

		Historical 2016	**Current 2017**	**Forecast 2018**
Low Voltage Switchgear Credit (if applicable, enter as a negative value)	$			

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2018 RTSR Workform for Electricity Distributors

In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants on Sheet "4. RRR Data". For Hydro One Sub-transmission Rates, if you are charged a *combined* Line and Transformer connection rate, please ensure that both the line connection and transformer connection columns are completed.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	115,900	$3.66	424,677		$0.00			$0.00		$ -
February	117,903	$3.66	432,023		$0.00			$0.00		$ -
March	108,929	$3.67	399,255		$0.00			$0.00		$ -
April	98,066	$3.66	359,174		$0.00			$0.00		$ -
May	67,790	$3.66	248,240		$0.00			$0.00		$ -
June	62,794	$3.66	229,826		$0.00			$0.00		$ -
July	75,871	$3.66	277,823		$0.00			$0.00		$ -
August	81,297	$3.66	297,712		$0.00			$0.00		$ -
September	77,471	$3.66	283,672		$0.00			$0.00		$ -
October	83,357	$3.66	305,259		$0.00			$0.00		$ -
November	102,977	$3.66	377,170		$0.00			$0.00		$ -
December	117,948	$3.66	432,063		$0.00			$0.00		$ -
Total	1,110,304	$ 3.66	$ 4,066,893	-	$ -	$ -	-	$ -	$ -	$ -

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January		$0.00			$0.00			$0.00		$ -
February		$0.00			$0.00			$0.00		$ -
March		$0.00			$0.00			$0.00		$ -
April		$0.00			$0.00			$0.00		$ -
May		$0.00			$0.00			$0.00		$ -
June		$0.00			$0.00			$0.00		$ -
July		$0.00			$0.00			$0.00		$ -
August		$0.00			$0.00			$0.00		$ -
September		$0.00			$0.00			$0.00		$ -
October		$0.00			$0.00			$0.00		$ -
November		$0.00			$0.00			$0.00		$ -
December		$0.00			$0.00			$0.00		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (I) (if needed)	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January		$0.00			$0.00			$0.00		$ -
February		$0.00			$0.00			$0.00		$ -
March		$0.00			$0.00			$0.00		$ -
April		$0.00			$0.00			$0.00		$ -
May		$0.00			$0.00			$0.00		$ -
June		$0.00			$0.00			$0.00		$ -
July		$0.00			$0.00			$0.00		$ -
August		$0.00			$0.00			$0.00		$ -
September		$0.00			$0.00			$0.00		$ -
October		$0.00			$0.00			$0.00		$ -
November		$0.00			$0.00			$0.00		$ -
December		$0.00			$0.00			$0.00		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

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2018 RTSR Workform for Electricity Distributors

In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants on Sheet "4. RRR Data". For Hydro One Sub-transmission Rates, if you are charged a *combined* Line and Transformer connection rate, please ensure that both the line connection and transformer connection columns are completed.

Add Extra Host Here (II) (if needed)	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January		$0.00			$0.00			$0.00		$ -
February		$0.00			$0.00			$0.00		$ -
March		$0.00			$0.00			$0.00		$ -
April		$0.00			$0.00			$0.00		$ -
May		$0.00			$0.00			$0.00		$ -
June		$0.00			$0.00			$0.00		$ -
July		$0.00			$0.00			$0.00		$ -
August		$0.00			$0.00			$0.00		$ -
September		$0.00			$0.00			$0.00		$ -
October		$0.00			$0.00			$0.00		$ -
November		$0.00			$0.00			$0.00		$ -
December		$0.00			$0.00			$0.00		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	115,900	$3.66	$ 424,677	-	$0.00	$ -	-	$0.00	$ -	$ -
February	117,903	$3.66	$ 432,023	-	$0.00	$ -	-	$0.00	$ -	$ -
March	108,929	$3.67	$ 399,255	-	$0.00	$ -	-	$0.00	$ -	$ -
April	98,066	$3.66	$ 359,174	-	$0.00	$ -	-	$0.00	$ -	$ -
May	67,790	$3.66	$ 248,240	-	$0.00	$ -	-	$0.00	$ -	$ -
June	62,794	$3.66	$ 229,826	-	$0.00	$ -	-	$0.00	$ -	$ -
July	75,871	$3.66	$ 277,823	-	$0.00	$ -	-	$0.00	$ -	$ -
August	81,297	$3.66	$ 297,712	-	$0.00	$ -	-	$0.00	$ -	$ -
September	77,471	$3.66	$ 283,672	-	$0.00	$ -	-	$0.00	$ -	$ -
October	83,357	$3.66	$ 305,259	-	$0.00	$ -	-	$0.00	$ -	$ -
November	102,977	$3.66	$ 377,170	-	$0.00	$ -	-	$0.00	$ -	$ -
December	117,948	$3.66	$ 432,063	-	$0.00	$ -	-	$0.00	$ -	$ -
Total	1,110,304	$ 3.66	$ 4,066,893	-	$ -	$ -	-	$ -	$ -	$ -

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2018 RTSR Workform
for Electricity Distributors

The purpose of this sheet is to calculate the expected billing when current 2017 Uniform Transmission Rates are applied against historical 2016 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	115,900	$ 3.6600	$ 424,194	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
February	117,903	$ 3.6600	$ 431,526	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
March	108,929	$ 3.6600	$ 398,681	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
April	98,066	$ 3.6600	$ 358,923	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
May	67,790	$ 3.6600	$ 248,113	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
June	62,794	$ 3.6600	$ 229,826	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
July	75,871	$ 3.6600	$ 277,687	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
August	81,297	$ 3.6600	$ 297,548	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
September	77,471	$ 3.6600	$ 283,543	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
October	83,357	$ 3.6600	$ 305,087	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
November	102,977	$ 3.6600	$ 376,895	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
December	117,948	$ 3.6600	$ 431,689	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
Total	1,110,304	$ 3.66	$ 4,063,713	-	$ -	$ -	-	$ -	$ -	$ -

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ 3.1942	$ -	-	$ 0.7710	$ -	-	$ 1.7493	$ -	$ -
February	-	$ 3.1942	$ -	-	$ 0.7710	$ -	-	$ 1.7493	$ -	$ -
March	-	$ 3.1942	$ -	-	$ 0.7710	$ -	-	$ 1.7493	$ -	$ -
April	-	$ 3.1942	$ -	-	$ 0.7710	$ -	-	$ 1.7493	$ -	$ -
May	-	$ 3.1942	$ -	-	$ 0.7710	$ -	-	$ 1.7493	$ -	$ -
June	-	$ 3.1942	$ -	-	$ 0.7710	$ -	-	$ 1.7493	$ -	$ -
July	-	$ 3.1942	$ -	-	$ 0.7710	$ -	-	$ 1.7493	$ -	$ -
August	-	$ 3.1942	$ -	-	$ 0.7710	$ -	-	$ 1.7493	$ -	$ -
September	-	$ 3.1942	$ -	-	$ 0.7710	$ -	-	$ 1.7493	$ -	$ -
October	-	$ 3.1942	$ -	-	$ 0.7710	$ -	-	$ 1.7493	$ -	$ -
November	-	$ 3.1942	$ -	-	$ 0.7710	$ -	-	$ 1.7493	$ -	$ -
December	-	$ 3.1942	$ -	-	$ 0.7710	$ -	-	$ 1.7493	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (I)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (II)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount

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2018 RTSR Workform for Electricity Distributors

The purpose of this sheet is to calculate the expected billing when current 2017 Uniform Transmission Rates are applied against historical 2016 transmission units.

January	115,900	$3.66	$ 424,194	-	$0.00	$ -	-	$0.00	$ -	$ -
February	117,903	$3.66	$ 431,526	-	$0.00	$ -	-	$0.00	$ -	$ -
March	108,929	$3.66	$ 398,681	-	$0.00	$ -	-	$0.00	$ -	$ -
April	98,066	$3.66	$ 358,923	-	$0.00	$ -	-	$0.00	$ -	$ -
May	67,790	$3.66	$ 248,113	-	$0.00	$ -	-	$0.00	$ -	$ -
June	62,794	$3.66	$ 229,826	-	$0.00	$ -	-	$0.00	$ -	$ -
July	75,871	$3.66	$ 277,687	-	$0.00	$ -	-	$0.00	$ -	$ -
August	81,297	$3.66	$ 297,548	-	$0.00	$ -	-	$0.00	$ -	$ -
September	77,471	$3.66	$ 283,543	-	$0.00	$ -	-	$0.00	$ -	$ -
October	83,357	$3.66	$ 305,087	-	$0.00	$ -	-	$0.00	$ -	$ -
November	102,977	$3.66	$ 376,895	-	$0.00	$ -	-	$0.00	$ -	$ -
December	117,948	$3.66	$ 431,689	-	$0.00	$ -	-	$0.00	$ -	$ -
Total	1,110,304	$ 3.66	$ 4,063,713	-	$ -	$ -	-	$ -	$ -	$ -

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2018 RTSR Workform for Electricity Distributors

The purpose of this sheet is to calculate the expected billing when forecasted 2018 Uniform Transmission Rates are applied against historical 2016 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	115,900	$ 3.6600	$ 424,194	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
February	117,903	$ 3.6600	$ 431,526	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
March	108,929	$ 3.6600	$ 398,681	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
April	98,066	$ 3.6600	$ 358,923	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
May	67,790	$ 3.6600	$ 248,113	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
June	62,794	$ 3.6600	$ 229,826	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
July	75,871	$ 3.6600	$ 277,687	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
August	81,297	$ 3.6600	$ 297,548	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
September	77,471	$ 3.6600	$ 283,543	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
October	83,357	$ 3.6600	$ 305,087	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
November	102,977	$ 3.6600	$ 376,895	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
December	117,948	$ 3.6600	$ 431,689	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
Total	1,110,304	$ 3.66	$ 4,063,713	-	$ -	$ -	-	$ -	$ -	$ -

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (I)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (II)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount

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2018 RTSR Workform for Electricity Distributors

The purpose of this sheet is to calculate the expected billing when forecasted 2018 Uniform Transmission Rates are applied against historical 2016 transmission units.

January	115,900	$ 3.66	424,194	-	$ -	-	-	$ -	-	$ -
February	117,903	$ 3.66	431,526	-	$ -	-	-	$ -	-	$ -
March	108,929	$ 3.66	398,681	-	$ -	-	-	$ -	-	$ -
April	98,066	$ 3.66	358,923	-	$ -	-	-	$ -	-	$ -
May	67,790	$ 3.66	248,113	-	$ -	-	-	$ -	-	$ -
June	62,794	$ 3.66	229,826	-	$ -	-	-	$ -	-	$ -
July	75,871	$ 3.66	277,687	-	$ -	-	-	$ -	-	$ -
August	81,297	$ 3.66	297,548	-	$ -	-	-	$ -	-	$ -
September	77,471	$ 3.66	283,543	-	$ -	-	-	$ -	-	$ -
October	83,357	$ 3.66	305,087	-	$ -	-	-	$ -	-	$ -
November	102,977	$ 3.66	376,895	-	$ -	-	-	$ -	-	$ -
December	117,948	$ 3.66	431,689	-	$ -	-	-	$ -	-	$ -
Total	1,110,304	$ 3.66	$ 4,063,713	-	$ -	$ -	-	$ -	$ -	$ -

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2017 RTSR Workform
for Electricity Distributors

The purpose of this sheet is to re-align the current RTS Network Rates to recover current wholesale network costs.

Rate Class	Rate Description	Unit	Current RTSR-Network	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Adjusted RTSR Network
Residential	RTSR - Network	kWh	0.0059	302,866,189		1,786,911	46.2%	1,877,795	0.0062
General Service Less Than 50 kW	RTSR - Network	kWh	0.0055	96,682,353		531,753	13.8%	558,799	0.0058
General Service 50 to 4,999 kW	RTSR - Network	kW	2.2455		418,637	940,049	24.3%	987,861	2.3597
General Service 50 to 4,999 kW – Interval Metered	RTSR - Network	kW	2.8240		203,435	574,500	14.9%	603,720	2.9676
Unmetered Scattered Load	RTSR - Network	kWh	0.0055	1,562,242		8,592	0.2%	9,029	0.0058
Sentinel Lighting	RTSR - Network	kW	1.7021		630	1,072	0.0%	1,127	1.7887
Street Lighting	RTSR - Network	kW	1.6935		14,262	24,153	0.6%	25,381	1.7796

The purpose of this table is to re-align the current RTS Connection Rates to recover current wholesale connection costs.

Rate Class	Rate Description	Unit	Current RTSR-Connection	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Adjusted RTSR-Connection
Residential	RTSR - Connection	kWh		302,866,189		0	#DIV/0!	#DIV/0!	0.0000
General Service Less Than 50 kW	RTSR - Connection	kWh		96,682,353		0	#DIV/0!	#DIV/0!	0.0000
General Service 50 to 4,999 kW	RTSR - Connection	kW			418,637	0	#DIV/0!	#DIV/0!	0.0000
General Service 50 to 4,999 kW – Interval Metered	RTSR - Connection	kW			203,435	0	#DIV/0!	#DIV/0!	0.0000
Unmetered Scattered Load	RTSR - Connection	kWh		1,562,242		0	#DIV/0!	#DIV/0!	0.0000
Sentinel Lighting	RTSR - Connection	kW			630	0	#DIV/0!	#DIV/0!	0.0000
Street Lighting	RTSR - Connection	kW			14,262	0	#DIV/0!	#DIV/0!	0.0000

The purpose of this table is to update the re-aligned RTS Network Rates to recover future wholesale network costs.

Rate Class	Rate Description	Unit	Adjusted RTSR-Network	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR-Network
Residential	RTSR - Network	kWh	0.0062	302,866,189		1,877,795	46.2%	1,877,795	**0.0062**
General Service Less Than 50 kW	RTSR - Network	kWh	0.0058	96,682,353		558,799	13.8%	558,799	**0.0058**
General Service 50 to 4,999 kW	RTSR - Network	kW	2.3597		418,637	987,861	24.3%	987,861	**2.3597**
General Service 50 to 4,999 kW – Interval Metered	RTSR - Network	kW	2.9676		203,435	603,720	14.9%	603,720	**2.9676**
Unmetered Scattered Load	RTSR - Network	kWh	0.0058	1,562,242		9,029	0.2%	9,029	**0.0058**
Sentinel Lighting	RTSR - Network	kW	1.7887		630	1,127	0.0%	1,127	**1.7887**
Street Lighting	RTSR - Network	kW	1.7796		14,262	25,381	0.6%	25,381	**1.7796**

The purpose of this table is to update the re-aligned RTS Connection Rates to recover future wholesale connection costs.

Rate Class	Rate Description	Unit	Adjusted RTSR-Connection	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR-Connection
Residential	RTSR - Connection	kWh	0.0000	302,866,189		0	0.0%	0	**0.0000**
General Service Less Than 50 kW	RTSR - Connection	kWh	0.0000	96,682,353		0	0.0%	0	**0.0000**
General Service 50 to 4,999 kW	RTSR - Connection	kW	0.0000		418,637	0	0.0%	0	**0.0000**
General Service 50 to 4,999 kW – Interval Metered	RTSR - Connection	kW	0.0000		203,435	0	0.0%	0	**0.0000**
Unmetered Scattered Load	RTSR - Connection	kWh	0.0000	1,562,242		0	0.0%	0	**0.0000**
Sentinel Lighting	RTSR - Connection	kW	0.0000		630	0	0.0%	0	**0.0000**
Street Lighting	RTSR - Connection	kW	0.0000		14,262	0	0.0%	0	**0.0000**

APPENDIX 2

Current Tariff of Rates

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2017

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

EB-2016-0102

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a single family unit, non-commercial. This can be a separately metered living accommodation, town house, apartment, semi-detached, duplex, triplex or quadruplex with residential zoning. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	16.79
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Rate Rider for Application of Tax Change (2017) - effective until April 30, 2018	$	0.05
Distribution Volumetric Rate	$/kWh	0.0104
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2017) - effective until April 30, 2018	$/kWh	(0.0001)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0059

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - Not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0021
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2017

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

EB-2016-0102

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly peak demand is less than, or is forecast to be less than, 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	17.11
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0205
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2017) - effective until April 30, 2018	$/kWh	0.0019
Rate Rider for Application of Tax Change (2017) - effective until April 30, 2018	$/kWh	0.0001
Retail Transmission Rate - Network Service Rate	$/kWh	0.0055

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - Not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0021
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2017

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

EB-2016-0102

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly peak demand used for billing purposes over the past 12 months is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	114.46
Distribution Volumetric Rate	$/kW	5.4372
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2017) - effective until April 30, 2018	$/kW	0.0680
Rate Rider for Application of Tax Change (2017) - effective until April 30, 2018	$/kW	0.0101
Retail Transmission Rate - Network Service Rate	$/kW	2.2455
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	2.8240

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - Not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0021
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information documentation with regard to electrical demand/consumption of the proposed unmetered load. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the Distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	12.69
Distribution Volumetric Rate	$/kWh	0.0310
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2017) - effective until April 30, 2018	$/kWh	(0.0012)
Rate Rider for Application of Tax Change (2017) - effective until April 30, 2018	$/kWh	0.0001
Retail Transmission Rate - Network Service Rate	$/kWh	0.0055

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - Not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0021
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification applies to safety/security lighting with a Residential or General Service customer. This is typically exterior lighting, and unmetered. Consumption is estimated based on the equipment rating and estimated hours of use. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	2.93
Distribution Volumetric Rate	$/kW	27.3551
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2017) - effective until April 30, 2018	$/kW	(1.0749)
Rate Rider for Application of Tax Change (2017) - effective until April 30, 2018	$/kW	0.0793
Retail Transmission Rate - Network Service Rate	$/kW	1.7021

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - Not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0021
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2017

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EB-2016-0102

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	2.94
Distribution Volumetric Rate	$/kW	19.1736
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2017) - effective until April 30, 2018	$/kW	(0.6973)
Rate Rider for Application of Tax Change (2017) - effective until April 30, 2018	$/kW	0.0620
Retail Transmission Rate - Network Service Rate	$/kW	1.6935

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - Not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0021
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2017

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EB-2016-0102

microFIT SERVICE CLASSIFICATION

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

APPLICATION

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

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

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

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EB-2016-0102

ALLOWANCES

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

SPECIFIC SERVICE CHARGES

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

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

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Customer Administration

Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned Cheque (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge - no disconnection	$	30.00
Collection of account charge - no disconnection - after regular hours	$	165.00
Disconnect/Reconnect at Meter - during regular hours	$	65.00
Disconnect/Reconnect at Meter - after regular hours	$	185.00
Disconnect/Reconnect at Pole - during regular hours	$	185.00
Disconnect/Reconnect at Pole - after regular hours	$	415.00
Install/Remove Load Control Device - during regular hours	$	65.00
Install/Remove Load Control Device - after regular hours	$	185.00

Other

Special meter reads	$	30.00
Service call - customer owned equipment		Time & Materials
Service call - after regular hours		Time & Materials
Temporary service - install & remove - overhead - no transformer		Time & Materials
Temporary service - install & remove - underground - no transformer		Time & Materials
Temporary service - install & remove - overhead - with transformer		Time & Materials
Specific charge for access to the power poles - $/pole/year (with the exception of wireless attachments)	$	22.35
Removal of overhead lines - during regular hours		Time & Materials
Removal of overhead lines - after hours		Time & Materials
Roadway escort - after regular hours		Time & Materials

RETAIL SERVICE CHARGES (if applicable)

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

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

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

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

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

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2017

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

EB-2016-0102

LOSS FACTORS

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

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0489
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0385

APPENDIX 3

Proposed Tariff of Rates

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2018

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

EB-2017-0071

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a single family unit, non-commercial. This can be a separately metered living accommodation, town house, apartment, semi-detached, duplex, triplex or quadruplex with residential zoning. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	24.87
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.57
Distribution Volumetric Rate	$/kWh	0.0088
Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 - Applicable only for Non-RPP Customers	$/kWh	0.0007
Rate Rider for Disposition of Deferral/Variance Accounts - Group 1 (2018) - effective until April 30, 2019	$/kWh	-0.0049
Rate Rider for Disposition of Deferral/Variance Accounts - Group 2 (2018) effective until April 30, 2019	$	-0.08
Rate Rider For Disposition of LRAMVA - effective until April 30, 2019	$/kWh	0.0002
Retail Transmission Rate - Network Service Rate	$/kWh	0.0062

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2018

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EB-2017-0071

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly peak demand is less than, or is forecast to be less than, 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	21.04
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.57
Distribution Volumetric Rate	$/kWh	0.0252
Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 - Applicable only for Non-RPP Customers	$/kWh	0.0007
Rate Rider for Disposition of Deferral/Variance Accounts - Group 1 (2018) - effective until April 30, 2019	$/kWh	-0.0050
Rate Rider for Disposition of Deferral/Variance Accounts - Group 2 (2018) effective until April 30, 2019	$/kWh	-0.0001
Rate Rider For Disposition of LRAMVA - effective until April 30, 2019	$/kWh	0.0028
Retail Transmission Rate - Network Service Rate	$/kWh	0.0058

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2018

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approved schedules of Rates, Charges and Loss Factors

EB-2017-0071

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly peak demand used for billing purposes over the past 12 months is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	140.76
Distribution Volumetric Rate	$/kW	6.6563
Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 - Applicable only for Non-RPP Customers	$/kWh	0.0007
Rate Rider for Disposition of Deferral/Variance Accounts - Group 1 (2018) - effective until April 30, 2019	$/kW	-1.9850
Rate Rider for Disposition of Deferral/Variance Accounts - Group 2 (2018) effective until April 30, 2019	$/kW	-0.0399
Rate Rider For Disposition of LRAMVA - effective until April 30, 2019	$/kW	0.1355
Retail Transmission Rate - Network Service Rate	$/kW	2.3597
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	2.9676

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2018

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EB-2017-0071

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information documentation with regard to electrical demand/consumption of the proposed unmetered load. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the Distributor's Conditions of Service.

APPLICATION

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	15.06
Distribution Volumetric Rate	$/kWh	0.0368
Rate Rider for Disposition of Deferral/Variance Accounts - Group 1 (2018) - effective until April 30, 2019	$/kWh	-0.0050
Rate Rider for Disposition of Deferral/Variance Accounts - Group 2 (2018) effective until April 30, 2019	$/kWh	-0.0001
Rate Rider For Disposition of LRAMVA - effective until April 30, 2019	$/kWh	-0.0012
Retail Transmission Rate - Network Service Rate	$/kWh	0.0058

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2018

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EB-2017-0071

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification applies to safety/security lighting with a Residential or General Service customer. This is typically exterior lighting, and unmetered. Consumption is estimated based on the equipment rating and estimated hours of use. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	3.60
Distribution Volumetric Rate	$/kW	33.6416
Rate Rider for Disposition of Deferral/Variance Accounts - Group 1 (2018) - effective until April 30, 2019	$/kW	-1.7732
Rate Rider for Disposition of Deferral/Variance Accounts - Group 2 (2018) effective until April 30, 2019	$/kW	-0.0356
Rate Rider For Disposition of LRAMVA - effective until April 30, 2019	$/kW	-1.7711
Retail Transmission Rate - Network Service Rate	$/kW	1.7887

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2018

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

EB-2017-0071

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	1.42
Distribution Volumetric Rate	$/kW	9.2724
2019 - Applicable only for Non-RPP Customers	$/kWh	0.0007
Rate Rider for Disposition of Deferral/Variance Accounts - Group 1 (2018) - effective until April 30, 2019	$/kW	-1.7661
Rate Rider for Disposition of Deferral/Variance Accounts - Group 2 (2018) effective until April 30, 2019	$/kW	-0.0343
Rate Rider For Disposition of LRAMVA - effective until April 30, 2019	$/kW	8.6771
Retail Transmission Rate - Network Service Rate	$/kW	1.7796

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2018

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

EB-2017-0071

microFIT SERVICE CLASSIFICATION

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

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2018

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EB-2017-0071

ALLOWANCES

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

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2018

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

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SPECIFIC SERVICE CHARGES

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

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

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

Customer Administration		
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned Cheque (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge - no disconnection	$	30.00
Collection of account charge - no disconnection - after regular hours	$	165.00
Disconnect/Reconnect at Meter - during regular hours	$	65.00
Disconnect/Reconnect at Meter - after regular hours	$	185.00
Disconnect/Reconnect at Pole - during regular hours	$	185.00
Disconnect/Reconnect at Pole - after regular hours	$	415.00
Install/Remove Load Control Device - during regular hours	$	65.00
Install/Remove Load Control Device - after regular hours	$	185.00
Other		
Special meter reads	$	30.00
Service call - customer owned equipment		Time & Materials
Service call - after regular hours		Time & Materials
Temporary service - install & remove - overhead - no transformer		Time & Materials
Temporary service - install & remove - underground - no transformer		Time & Materials
Temporary service - install & remove - overhead - with transformer		Time & Materials
Specific charge for access to the power poles - $/pole/year (with the exception of wireless attachments)	$	22.35
Removal of overhead lines - during regular hours		Time & Materials
Removal of overhead lines - after hours		Time & Materials
Roadway escort - after regular hours		Time & Materials

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2018

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

EB-2017-0071

RETAIL SERVICE CHARGES (if applicable)

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

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

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

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

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

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2018

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

EB-2017-0071

LOSS FACTORS

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

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0489
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0385

EXHIBIT 9:

DEFERRAL AND VARIANCE ACCOUNTS

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APPENDIX 2 Analysis Workform

APPENDIX 3 Certificate

Exhibit 9: Deferral and Variance Accounts

PUC Distribution has included in this Cost of Service ("COS") Application, a request for approval for disposition of Group 1 and Group 2 Deferral and Variance Account ("DVAs") balances as at December 31, 2016 and the forecasted interest through April 30, 2018. PUC Distribution has followed the Board's guidance in the *Accounting Procedures Handbook and FAQ's* ("APH") for recording amounts in the deferral and variance accounts. Such guidance also includes the Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative ("EDDVAR Report").

Table 9-1 contains descriptions of all the outstanding DVAs. PUC Distribution confirms that it has used the DVAs in the same manner described in the APH, and the account balance in Table 9-1 reconciles with the trial balance reported through the Electricity Reporting and Record-keeping Requirements and PUC Distribution's Audited Financial Statements.

PUC Distribution has provided a continuity schedule of the Group 1 and Group 2 DVAs in the live Excel format model named "2018_DVA_Continuity_Schedule_CoS" ("EDDVAR model").

The forecasted interest on December 31, 2016 DVA balances is calculated using the Board's prescribed rate of 1.10% for the period of January 1, 2017 to September 30, 2017 and 1.5% thereafter until April 30, 2018. The interest rates by quarter for each year are provided in Table 9-4 in this Exhibit.

A breakdown of energy sales and cost of power expense balances, as reported in the Audited Financial Statements by PUC Distribution, is provided in Table 9-5.

PUC Distribution will continue or discontinue using the Group 2 accounts on a go-forward basis as outlined in Table 9-6 in this Exhibit.

PUC Distribution has accepted the allocators as indicated in the EDDVAR Report.

PUC Distribution is not requesting any new accounts or sub-accounts in this COS application.

PUC Distribution confirms that the IESO Global Adjustment Charge is pro-rated into the Regulated Price Plan ("RPP") and Non-RPP portions.

Account Balances

Table 9-1 contains account balances from the PUC Distribution Audited Financial Statements as at December 31, 2016 and agrees to the 2016 year end balances for Reporting and Record Keeping Requirement ("RRR") filing E2.1.7 Trial Balance as filed April 30, 2017 with the Board.

PUC Distribution has used the DVAs in the same manner described in the APH.

Table 9-1 - December 31, 2016 Audited Balances – DVAs

Account Description	USoA #	Total Principal (Dec 31, 2016)	Total Interest (Dec 31, 2016)	Total Principal & Interest (Dec 31, 2016)	2.1.7 RRR Balances (Dec, 31, 2016)	Variance
Group 1 Accounts:						
Smart Metering Entity Charge Variance Account	1551	$33,839	$1,428	$35,267	$35,268	($1)
RSVA - Wholesale Market Service Charge	1580	($2,364,294)	($33,633)	($2,397,927)	($2,397,926)	($1)
RSVA - Retail Transmission Network Charge	1584	($98,043)	$1,022	($97,021)	($97,020)	($1)
RSVA - Power (excluding Global Adjustment)	1588	($614,316)	$8,898	($605,418)	($605,420)	$2
RSVA - Global Adjustment	1589	$73,743	$43,356	$117,099	$117,099	$0
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	$6,416	($6,414)	$2	$1	$1
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	$127,547	($118,123)	$9,424	$9,426	($2)
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	($1,190)	($57,862)	($59,052)	($59,051)	($1)
Disposition and Recovery/Refund of Regulatory Balances (2016)	1595	$735,583	($116,319)	$619,264	$619,264	$0
Subtotal - Group 1 Accounts		**($2,100,715)**	**($277,647)**	**($2,378,362)**	**($2,378,360)**	**($2)**
Group 2 Accounts:						
Other Regulatory Assets - Sub-Account - Other	1508	($365,400)	$0	($365,400)	($365,400)	$0
Retail Cost Variance Account - Retail	1518	($139,578)	($5,038)	($144,616)	($144,622)	$6
Retail Cost Variance Account - STR	1548	$78,206	$2,900	$81,106	$81,105	$1
Other Deferred Credits	2425	$365,400	$0	$365,400	$365,400	$0
Subtotal - Group 2 Accounts		**($61,372)**	**($2,138)**	**($63,510)**	**($63,517)**	**$7**
Other Accounts:						
LRAM Variance Account	1568	($13,391)	$2,889	($10,501)	($10,502)	$1
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	($5,525)	$9,372	$3,847	$3,847	$0
Subtotal - Other Accounts		**($18,916)**	**$12,262**	**($6,654)**	**($6,655)**	**$1**
Total		**($2,181,003)**	**($267,523)**	**($2,448,526)**	**($2,448,532)**	**$5**

Energy Sales and Cost of Power

The sale of energy is a flow through revenue and the cost of power is a flow through expense. Energy sales and the cost of power expense by component are presented in Table 9-2 as reported in the Audited Financial Statements and the USoA within the RRR filing 2.1.7. PUC Distribution has no profit or loss resulting from the flow through of energy revenues and expenses.

Table 9-2 – Energy Revenue and Cost of Power Expenses

Account Description	USoA #	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual
ENERGY REVENUE:						
Residential Energy Sales	4006	(24,315,891)	(28,076,344)	(27,897,738)	(31,985,149)	(32,865,176)
Street Lighting Energy Sales	4025	(619,097)	(575,899)	(742,686)	(797,540)	(635,219)
Sentinel Energy Sales	4030	(22,185)	(22,420)	(25,400)	(25,550)	(28,269)
General Energy Sales	4035	(26,667,481)	(30,479,498)	(31,474,604)	(36,303,241)	(39,641,148)
Energy Sales for Resale	4055	(1,858,670)	(1,968,788)	(2,525,618)	(1,773,124)	(1,298,216)
Wholesale Market Service Charges	4062	(3,157,589)	(3,338,421)	(3,307,697)	(2,555,859)	(3,062,529)
Network	4066	(3,932,403)	(4,100,462)	(4,155,953)	(4,357,671)	(4,066,893)
Smart Meter Entity Charge	4076	-	(207,310)	(343,438)	(312,254)	(302,117)
TOTAL ENERGY REVENUE		**(60,573,316)**	**(68,769,142)**	**(70,473,134)**	**(78,110,388)**	**(81,899,567)**
COST OF POWER EXPENSES:						
Power Purchased	4705	40,412,099	45,668,915	49,371,071	50,769,485	49,506,357
Global Adjustment	4707	-	15,454,034	13,294,976	20,115,120	24,961,672
Wholesale Market Service	4708	3,157,589	3,338,421	3,307,697	2,555,859	3,062,529
Network	4714	3,932,403	4,100,462	4,155,953	4,357,671	4,066,893
Other Expenses	4720	13,071,226				
Smart Meter Entity Charge Total	4751	-	207,310	343,438	312,254	302,117
TOTAL COST OF POWER EXPENSES		**60,573,317**	**68,769,142**	**70,473,135**	**78,110,389**	**81,899,568**
NET INCOME		**1**	**-**	**1**	**1**	**1**

Interest Rates Applied

PUC Distribution has used the Board's prescribed interest rates when calculating carrying charges on the DVA balances. Table 9-3 below shows the Board's prescribed interest rates starting from 2014 Q1 onward. Interest is calculated based on the opening monthly principle balances.

In accordance with the filing requirements, the most recent posted interest rate (1.5% for Q1 of 2018) has been used to forecast carrying charges to April 30, 2018. The interest component for DVA balances is included in the principal balance for each account.

Table 9-3 - Interest Rates Applied to Deferral and Variance Accounts

Period	Interest Rate
Q1 2014	1.47%
Q2 2014	1.47%
Q3 2014	1.47%
Q4 2014	1.47%
Q1 2015	1.47%
Q2 2015	1.10%
Q3 2015	1.10%
Q4 2015	1.10%
Q1 2016	1.10%
Q2 2016	1.10%
Q3 2016	1.10%
Q4 2016	1.10%
Q1 2017	1.10%
Q2 2017	1.10%
Q3 2017	1.10%
Q4 2017	1.50%
Q1 2018	1.50%
Q2 2018 Forecast	1.50%

Proposed Disposition

PUC Distribution is requesting a net disposition of $2,642,670 to be refunded to customers, based on the 2016 year end balances plus 2017 adjustments and interest from January 1, 2017 to April 30, 2018. Details of each account disposition request are discussed in detail in the evidence that follows.

Table 9-4 – Proposed Disposition

Account Description	USoA #	Total Principal & Interest (Dec 31, 2016)	2017 Adjustment	Interest to April 30, 2018	Total Claim
Group 1 Accounts:					
Smart Metering Entity Charge Variance Account	1551	$35,267	$0	$575	$35,842
RSVA - Wholesale Market Service Charge	1580	($2,397,927)	$0	($40,193)	($2,438,120)
RSVA - Retail Transmission Network Charge	1584	($97,021)	$0	($1,667)	($98,688)
RSVA - Power (excluding Global Adjustment)	1588	($605,418)	$0	($10,443)	($615,861)
RSVA - Global Adjustment	1589	$117,099	$0	$1,254	$118,353
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	$2	$0	$109	$0
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	$9,424	$0	$2,168	$0
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	($59,052)	$0	($20)	($59,072)
Disposition and Recovery/Refund of Regulatory Balances (2016)	1595	$619,264	$0	$12,505	$0
Subtotal - Group 1 Accounts		**($2,378,362)**	**$0**	**($35,712)**	**($3,057,546)**
Group 2 Accounts:					
Other Regulatory Assets - Sub-Account - Other	1508	($365,400)	$0	($6,212)	$0
Retail Cost Variance Account - Retail	1518	($144,616)	$0	($2,373)	($146,989)
Retail Cost Variance Account - STR	1548	$81,106	$0	$1,330	$82,436
Other Deferred Credits	2425	$365,400	$0	$6,212	$0
Subtotal - Group 2 Accounts		**($63,510)**	**$0**	**($1,043)**	**($64,553)**
Other Accounts:					
LRAM Variance Account	1568	($10,501)	($476,485)	($9,693)	$475,677
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	$3,847	0	($94)	$3,753
Subtotal - Other Accounts		**($6,654)**	**($476,485)**	**($9,787)**	**$479,430**
Total		**($2,448,526)**	**($476,485)**	**($46,542)**	**($2,642,670)**

GROUP 1 ACCOUNT ANALYSIS

PUC Distribution last disposed of Group 1 account balances in its 2016 IRM Rate Application (EB-2015-0098). PUC Distribution has entered the Continuity data into Tab 2 of the EDDVAR Model from January 1, 2011 onwards.

The following sections provide details of the Group 1 accounts utilized by PUC Distribution and the respective disposition requests.

Account 1551: Smart Metering Entity Charge Variance Account

This account is used to record the difference between the Smart Meter Entity amounts billed to PUC Distribution customers and the charges paid to the IESO. PUC Distribution uses the accrual method. The Board prescribed interest rates is used to calculate the carrying charges.

PUC Distribution requests disposition of Account 1551 for the amount of $35,842 to be collected from customers, including interest to April 30, 2018.

Account 1580: RSVA - Wholesale Market Service Charge

This account is used to record the difference between the amounts charged by the IESO for wholesale market services and the amount billed to PUC Distribution customers using the Board Approved rates. PUC Distribution uses the accrual method. The Board prescribed interest rates is used to calculate the carrying charges.

PUC Distribution requests disposition of Account 1580 for the amount of $2,438,120 as a refund to customers, including interest to April 30, 2018.

Account 1584: RSVA - Retail Transmission Network Charge

This account is used to record the net of the amount charged by the IESO, based on the settlement invoice for transmission network services, and the amount billed to customers using the Board-approved Retail Transmission Rate for network services. PUC Distribution uses the accrual method. The Board prescribed interest rates is used to calculate the carrying charges.

PUC Distribution requests disposition of Account 1584 for the amount of $98,688 to be refunded to customers, including interest to April 30, 2018.

Account 1588: RSVA - Power (excluding Global Adjustment)

This account is used to recover the net difference between the energy amount billed to customers and the energy charged to PUC Distribution using the settlement invoice from the IESO. PUC Distribution uses the accrual method. The Board prescribed interest rates is used to calculate the carrying charges.

PUC Distribution requests disposition of Account 1588 for the amount of $615,861 as a refund to customers, including interest to April 30, 2018.

Account 1589: RSVA - Global Adjustment

This account is used to recover the net difference between the provincial benefit amount billed to non-RPP customers and the GA adjustment charge to PUC Distribution using the settlement invoice from the IESO. PUC Distribution uses the accrual method.

The Board prescribed interest rates are used to calculate the carrying charges.

PUC Distribution requests disposition of Account 1589 for the amount of $118,353 to be collected from non-RPP customers, including interest to April 30, 2018.

Account 1595: (2014) Disposition and Recovery/Refund of Regulatory Balances

This account includes the regulatory asset or liability balances authorized by the Board for recovery in rates or payments/credits made to customers. Separate sub-accounts are maintained for expenses, interest, and recovery amounts for each Board-approved recovery.

The amount requested for disposition below relates to residual balances from rate riders that concluded in 2015. The amount in account 1595 relates to amounts that should be refunded to non-RPP customers.

PUC Distribution uses the accrual method on this account and the Board prescribed interest rates is used to calculate the carrying charges.

PUC Distribution requests disposition of Account 1595 (2014) for the amount of $ $59,072 to be refunded to Non-RPP customers, including interest to April 30, 2018.

GROUP 2 AND OTHER ACCOUNT ANALYSIS

The total disposition amount for the group 2 and other accounts is $414,877. The following sections provide details of the Group 2 and Other accounts utilized by PUC Distribution and the respective disposition requests.

2.9.4 Retail Service Charges

Account 1518 – RCVA Retail

This account is used to recover the net difference between revenues derived from establishing service agreements and providing distributor-consolidated billing and costs of entering into service agreements and costs of providing distributor-consolidated billing. PUC Distribution confirms that the costs incorporated into the variance are incremental costs of providing retail services and are in accordance with Article 490.

Acct 1518	2011	2012	2013	2014	2015	2016
Opening	($351,582)	($388,123)	($419,726)	($61,527)	($88,407)	($115,728)
4082	$41,034	$32,699	$30,985	$28,305	$27,321	$23,850
5315	$4,493	$1,096	$1,062	$1,425	$0	$0
Disposal	$0	$0	$388,122	$0	$0	$0
Closing	($388,123)	($419,726)	($61,527)	($88,407)	($115,728)	($139,578)

PUC Distribution used the Board prescribed interest rates to calculate carrying estimated to April 30, 2018 at ($7,411).

PUC Distribution requests disposition of Account 1518 for the amount of $146,989 to be refunded to customers, including interest to April 30, 2018.

Account 1548 – RCVA STR

This account is used to recover the net difference between revenues derived from service transaction request services and the incremental cost of labour, information system maintenance costs, etc. to provide service transaction request services. PUC Distribution confirms that the costs incorporated into the variance are incremental costs of providing retail services and are in accordance with Article 490.

Acct 1548	2011	2012	2013	2014	2015	2016
Opening	$144,793	$161,141	$166,787	$34,686	$53,605	$66,349
4084	$723	$488	$470	$408	$360	$275
5315	$17,071	$6,134	$29,511	$19,326	$13,105	$12,131
Disposal	$0	$0	($161,142)	$0	$0	$0
Closing	$161,141	$166,787	$34,686	$53,605	$66,349	$78,206

PUC Distribution used the Board prescribed interest rates to calculate carrying charges estimated to April 30, 2018 at $4,230.

PUC Distribution requests disposition of Account 1548 for the amount of $82,436 to be collected from customers, including interest to April 30, 2018.

Account 1555: Smart Meter Capital and Recovery Offset Variance Account

This account is used to recover the net difference between revenues approved by the Board for smart meters and cost of smart meters prior to inclusion in the rate base. It also includes stranded meter costs.

The Board prescribed interest rates is used to calculate the carrying charges.

PUC Distribution requests disposition of Account 1555 for the amount of $3,753 to be collected from customers, including interest to April 30, 2018.

Account 1568: LRAM Variance Account

This account includes the lost revenue adjustment mechanism ("LRAM") variances in relation to the conservation and demand management ("CDM") programs or activities undertaken by PUC Distribution in accordance with Board prescribed requirements. The details of this claim are outlined the LRAMVA Work form. PUC Distribution requests disposition of Account 1568 for the amount of $475,677 to be collected from customers, including interest to April 30, 2018.

GROUP 2 ACCOUNTS – TO BE CONTINUED AND DISCONTINUED ON A GO-FORWARD BASIS

Table 9-5 below lists all Group 2 accounts which PUC Distribution will continue and discontinue on a going-forward basis.

Explanations for those accounts that will be discontinued are provided in Table 9-5.

Table 9-5 - Group 2 Accounts - Continue & Discontinue

Account Description	USoA #	Continue / Discontinue	Explanation
Group 2 and Other Accounts - Continue:			
Other Regulatory Assets - Sub-Account - Other	1508	Continue	On-going use
Retail Cost Variance Account - Retail	1518	Continue	On-going use
Retail Cost Variance Account - STR	1548	Continue	On-going use
Other Deferred Credits	2425	Continue	On-going use
LRAM Variance Account	1568	Continue	On-going use
Group 2 and Other Accounts - Discontinue:			
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	Discontinue	Smart meter implementation completed

2.9.5 Disposition of Deferral and Variance Accounts

Calculation of Rate Riders

For the calculation of proposed rate riders, PUC Distribution has utilized the billing determinants arising from the 2018 Load Forecast inclusive of CDM Adjustments, as presented in Table 9-6 below. For more details regarding the 2018 Load Forecast and billing determinants please see Exhibit 3.

Table 9-6 - Total Billing Determinants

Rate Class	Customer Numbers	kWh	kW
Residential	29,789	296,393,596	-
General Service < 50 kW	3,443	94,320,130	-
General Service 50 to 4,999 kW	353	248,349,153	624,500
Sentinel Lighting	348	218,403	616
Street Lighting	8,070	2,415,793	7,076
Unmetered Scattered Load	23	1,176,822	
Total	42,026	642,873,897	632,192

2.9.5.1 Disposition of Global Adjustment Variance

In accordance with the Board’s Filing Requirements it is stated that:

> “… distributors must establish separate rate riders to recover the balances in the RSVAs from Market Participants (“MPs”) who must not be allocated the RSVA account balances related to charges for which the MPs settle directly with the IESO”; and
>
> “Distributors who serve Class A customers per O. Reg 429/04 (i.e. customers greater than 5 MW) must propose an appropriate allocation for the recovery of the global adjustment variance balance based on their settlement process with the IESO.”

As of December 31, 2016, the PUC Distribution customer’s affected by these requirements is described as follows:

- No market participants settle directing with the IESO, therefore, no separate rate riders to recover RSVAs is required, and
- PUC Distribution has no customers classified as a Class A customer.

For Class B Non-RPP customers, PUC Distribution settles GA based on the First Estimate GA rate.

To develop the 2018 Non-RPP billing determinants to be applied to calculate the proposed GA rate riders, PUC Distribution calculated the relationship by rate class of the Non-RPP results as a percentage of the total by rate class for each the kWh consumption based on the February 2017 2.1.2 reports which provided the percentage of customers on RPP per rate class. PUC Distribution then applied the rate class specific percentage to the 2018 Load Forecast results presented in Table 9-6.

Table 9-7 - Billing Determinants for GA Rate Rider

Rate Class	**2017 % Non RPP**	**2018 kWh Non-RPP**
Residential	4.4%	13,130,236
General Service < 50 kW	8.0%	7,507,882
General Service 50 to 4,999 kV	63.9%	158,670,274
Sentinel Lighting	0.0%	-
Street Lighting	97.4%	2,353,224
Unmetered Scattered Load	0.0%	-
Total		181,661,616

The billing determinants used to develop the various rate riders are presented in Table 9-8 below.

Table 9-8 2018 Detailed Load Forecast Billing Determinants for Disposition Calculations

Rate Class	Customer Numbers	kWh	kW	2018 kWh Non-RPP less Class A
Residential	29,789	296,393,596	-	13,130,236
General Service < 50 kW	3,443	94,320,130	-	7,507,882
General Service 50 to 4,999 kW	353	248,349,153	624,500	158,670,274
Sentinel Lighting	348	218,403	616	-
Street Lighting	8,070	2,415,793	7,076	2,353,224
Unmetered Scattered Load	23	1,176,822	-	-
Total	42,026	642,873,897	632,192	181,661,616

Proposed Rate Riders

Consistent with the EDDVAR model provided by the Board, PUC Distribution has calculated the following rate riders:

- Rate Rider Calculation for Group 1 Deferral / Variance Accounts Balances (excluding Global Adj.)
- Rate Rider Calculation for RSVA - Power - Global Adjustment
- Rate Rider Calculation for Group 2 Accounts
- Rate Rider Calculation for Account 1568

Each calculation and results will be discussed in the sections below.

Rate Rider Calculation for Group 1 Deferral / Variance Accounts Balances (excluding Global Adj.)

- Account 1551 – allocated based on number of customers in the Residential and General Service < 50 kW classes
- Account 1580 – allocated based on total kWh
- Account 1584 – allocated based on total kWh
- Account 1588 – allocated based on total kWh

Table 9-9 Rate Rider Calculation for Group 1 Deferral / Variance Accounts Balances (excluding Global Adj.)

Rate Class	**Units**		**Allocated Balance (excluding 1589)**	**Rate Rider for Deferral/ Variance Accounts**
Residential	kWh	296,393,596	($1,449,525)	(0.0049)
General Service < 50 kW	kWh	94,320,130	($467,294)	(0.0050)
General Service 50 to 4,999 kW	kW	624,500	($1,239,649)	(1.9850)
Sentinel Lighting	kW	616	($1,092)	(1.7732)
Street Lighting	kW	7,076	($12,497)	(1.7661)
Unmetered Scattered Load	kWh	1,176,822	($5,842)	(0.0050)
Total			($3,175,899)	

Rate Rider Calculation for RSVA - Power - Global Adjustment

- Account 1589 – allocated based on kWh in Table 9-7

Table 9-10 Rate Rider Calculation for RSVA - Power - Global Adjustment

Rate Class	Units		Account 1589	Rate Rider for Deferral/ Variance Accounts
Residential	kWh	13,130,236	$8,554	0.0007
General Service < 50 kW	kWh	7,507,882	$4,891	0.0007
General Service 50 to 4,999 kW	kWh	158,670,274	$103,374	0.0007
Sentinel Lighting	kWh	-		
Street Lighting	kWh	2,353,224	$1,533	0.0007
Unmetered Scattered Load	kWh	-		
Total			$118,353	

Rate Rider Calculation for Group 2 Deferral / Variance Accounts Balances

- Account 1518 – Retail Cost Variance Account – Retail
- Account 1548 – Retail Cost Variance Account – STR

Table 9-11 Rate Rider Calculation for Group 2 Deferral / Variance Accounts Balances

Rate Class	Units		Allocated Balance	Rate Rider for Deferral/ Variance Accounts
Residential	Customers	29,789	($29,762)	(0.08)
General Service < 50 kW	kWh	94,320,130	($9,471)	(0.0001)
General Service 50 to 4,999 kW	kW	624,500	($24,938)	(0.0399)
Sentinel Lighting	kW	616	($22)	(0.0356)
Street Lighting	kW	7,076	($243)	(0.0343)
Unmetered Scattered Load	kWh	1,176,822	($118)	(0.0001)
Total			($64,435)	

Rate Rider Calculation for Account 1568

- Account 1568 – allocated based on results from LRAMVA Work form

Table 9-12 Rate Rider Calculation for LRAMVA

Rate Class	**Units**		**Account 1568**	**Rate Rider for Deferral/ Variance Accounts**
Residential	kWh	296,393,596	$67,426	0.0002
General Service < 50 kW	kWh	94,320,130	$264,755	0.0028
General Service 50 to 4,999 kW	kW	624,500	$84,638	0.1355
Sentinel Lighting	kW	616	($1,091)	(1.7711)
Street Lighting	kW	7,076	$61,399	8.6771
Unmetered Scattered Load	kWh	1,176,822	($1,450)	(0.0012)
Total			$475,677	

IESO SETTLEMENT PROCESS

Global Adjustment

On a monthly basis, PUC Distribution must settle with the IESO for Global Adjustment (GA). GA is applicable to all provincial customers who pay the Hourly Ontario Energy Price (“HOEP”), or have signed a retail contract, and accounts for the differences between the market price and the rates paid to regulated and contracted generators and for CDM programs.

The GA varies from month to month, responding to changes in both the HOEP and contract terms. Generally speaking, when the HOEP is lower, then the GA is higher in order to cover the additional costs.

PUC Distribution confirms that the GA charge is split between RPP and non-RPP.

Class B Customers

Class B customers include: (a) customers with a peak demand below 5MW (or who have opted into this category) and (b) residential and business customers who have a retail contract for electricity. As of December 31, 2016, all of PUC Distribution's large volume customers were included in Class B.

For Class B customers, the IESO provides three variations of the GA, which can be used by distributors to bill customers. These variations are described as follows:

1st Estimate Variation

The 1st Estimate for a given month comprises three components - an estimate of the GA costs based on the previous month, an estimate of Ontario demand for the given month, and a true up accounting for the difference between the previous month's 1st Estimate and the actual rate.

The 1st Estimate for the upcoming month is published on the last business day of the preceding month. For example, the 1st Estimate for April is published at the end of March.

PUC Distribution currently bills all Class B customers using the 1st Estimate Variation.

2nd Estimate Variation

The 2nd Estimate is a separate calculation based on actual GA costs and demand information available at the time it is published, an estimate for GA and demand for the remaining days of the month, and a true up accounting for the difference between the previous month's 2nd Estimate and the actual rate.

The 2nd Estimate for a given month is published on the last business day of that month. For example, the 2nd Estimate for April is published at the end of April.

PUC Distribution currently does not bill any Class B using the 2nd Estimate Variation. This is due to the fact that PUC Distribution does not wish to create inequities within rate classes related to the

GA variances accumulating the GA account 1589. Since PUC Distribution has ongoing monthly billing cycles, some customers within each rate class are billed based on a period which ends prior to the availability of the IESO's 2nd Estimate. Thus, by using only the 1st estimate, PUC Distribution ensures that all customers within a rate class contribute equally to the GA variance accumulating in account 1589. This ensures an equitable disposition of the 1589 variance account to all rate classes.

Actual Variation

The Actual rate, based on actual electricity demand and GA costs, is published on the tenth business day of each month. For example, the Actual rate for April is published on the tenth business day of May.

IESO Reporting Process

PUC Distribution settles with the IESO for the difference between spot and RPP pricing, for RPP customers within four business days of month end.

The RPP settlement variance is calculated for customers with Conventional Meters on Tiered pricing and customer with Smart Meters on Time of Use (TOU) pricing. PUC Distribution's billing system provides the kWh's billed to RPP customers each month, as well as the corresponding RPP revenue. In addition, the system also tracks the corresponding amounts (not billed) calculated at both the Hourly Ontario Energy Price (HOEP) and applicable monthly Global Adjustment (GA) 2nd Estimate rate. The settlement variance is calculated by subtracting the RPP revenues billed to consumers from the amounts calculated using HOEP plus the GA amount adjusted to reflect the final GA rate. This variance is then submitted for settlement to the IESO.

PUC Distribution uses the 1st Estimate rate for billing GA to its Non-RPP consumers. These amounts are used in the determination of RSVA-GA account 1589.

The GA amounts charged to PUC on the monthly IESO Settlement Invoices using the actual GA rate represents consumption for both RPP and Non-RPP consumers. These amounts are initially recorded in Cost of Power expense accounts used in determining the balance of RSVA-Power account 1588.

PUC Distribution's billing system provides the Non-RPP kWh's for each month which are multiplied by the applicable Actual GA rates. The resulting amounts are transferred from the RSVA-Power account 1588 to the RSVA-GA account 1589.

The residual balance in the RSVA-Power account 1588 is due to differences between the GA 2nd Estimate rate, used to settle with the IESO, and the GA actual rate invoiced by the IESO. In addition, the 1588 balance reflects settlement variances between the energy rates billed to customers and the energy rates invoiced by IESO.

The RSVA-GA account 1589 only records the net difference between the Global Adjustment revenue amounts billed to Non-RPP consumers and the calculated Global Adjustment expense for Non-RPP consumers.

Embedded generation kWh's are provided to the IESO each month for inclusion on the monthly settlement invoice. The IESO invoices PUC Distribution for amounts associated with the embedded generation, including GA.

PUC Distribution has completed the IESO RPP Self-Certification process, as required by all distributors. This documentation was submitted to the IESO by the March 31, 2017 due date.

PUC Distribution uses the IESO reconciliation as the basis for its monthly accounting accrual journal entries and subsequently reverses these accruals and records the actual IESO invoice when it is received.

The True-up Process

As described above, PUC Distribution reconciles the estimates of RPP and Non-RPP consumption to actuals on a monthly basis.

The total volume is determined by taking the actual kWh volume purchased from the IESO plus any embedded generation volume, to determine the total actual volume to be split between RPP and Non-RPP. An IT system query is run, which identifies monthly consumption for Non-RPP customers, with the difference being RPP volume.

The RPP volume is multiplied by the actual GA rate to determine the GA allocated to RPP customers and is netted against the estimate that was either paid to or received from the IESO on a monthly basis. This difference is then settled with the IESO on a monthly basis.

Embedded generation is taken into consideration with determining the total power purchases for the month. PUC Distribution has provided certification that there are robust processes and internal controls in place for the preparation, review, verification and oversight of account balances being proposed for disposition in the Application. This certification is attached at Appendix 3.

APPENDIX 1

PUC Distribution’s EDDVAR Disposition Model

Ontario Energy Board

2018 Deferral/Variance Account Workform

Utility Name	PUC Distribution Inc.
Service Territory	Sault Ste. Marie
Assigned EB Number	EB-2017-0071
Name of Contact and Title	Andrew Belsito, Rates and Regulatory Affairs Offic
Phone Number	705-257-9450
Email Address	andrew.belstio@ssmpuc.com

General Notes

Notes

🟩	Pale green cells represent input cells.
🟦	Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.
⬜	White cells contain fixed values, automatically generated values or formulae.

Ontario Energy Board

2018 Deferral/Variance Account Workform

Instructions for Tabs 2 to 7

Tab	Tab Details	Step	Instructions
2 - Continuity Schedule	This tab is the continuity schedule that shows all the accounts and the accumulation of the balances a utility has.	1	Complete the DVA continuity schedule. For all accounts, except for Account 1595, start inputting data from the year in which the GL balance was last disposed. For example, if in the 2017 rate application, DVA balances as at December 31, 2015 were approved for disposition, start the continuity schedule from 2015 by entering the closing 2014 balances in the Adjustments column under 2014. For all Account 1595 sub-accounts, complete the DVA continuity schedule for each Account 1595 vintage year that has a GL balance as at December 31, 2016 regardless of whether the account is being requested for disposition in the current application. For each Account 1595 sub-account, start inputting data from the year the sub-account started to accumulate a balance (i.e. the vintage year). For example, Account 1595 (2014) would have information starting in 2014, when the relevant balances approved for disposition were first transferred into Account 1595 (2014). The DVA continuity schedule currently starts from 2011, if a utility has an Account 1595 with a vintage year prior to 2011, then a separate schedule should be provided starting from the vintage year.
		2a	If you had any Class A customers at any point during the period that the Account 1589 GA balance accumulated (e.g. last disposition was for 2014 balances in the 2016 rate application, current balance requested for disposition accumulated from 2015 to 2016), check off the checkbox in cell BS13. If the checkbox is not checked off, then proceed to tabs 4 to 7 and complete the tabs accordingly. If the checkbox is checked off, tab 5.1 relating to Class A customer consumption will be generated, see step 7 to 10 below for further details.
		2b	If the checkbox in step 2a is checked off, another checkbox will pop up to the right of the checkbox. If you had any Class A customers at any point during the period that the Account 1580, sub-account CBR Class B balance accumulated (i.e. 2015 and 2016 or 2016), check off the checkbox. If the checkbox is not checked off, then the balance in the Account 1580, sub-account CBR Class B will be allocated and disposed with Account 1580 WMS, as a part of the general DVA rate rider. If the checkbox is checked off, then tab 5.3 will be generated. This tab will calculate the billing determinants applicable to Account 1580 sub-account CBR Class B, using information inputted in tab 5.1. See step 12 below for further details. The CBR Class B balance will be allocated in tab 5 and the rate rider will be calculated in tab 6.
		3	Enter the number of utility specific 1508 sub-accounts that are approved for the utility in the textbox in cell B50. The DVA continuity schedule will generate the number of utility specific 1508 sub-accounts starting in row 51. Input the name and the balances of the sub-account(s) starting in row 51. If a utility does not have utility specific 1508 sub-accounts, the generic 1508 sub-account Other will still be listed in the DVA continuity schedule. Check off the "check to dispose of account" checkbox in column BT for sub-accounts requested for disposition.
3. Appendix A	This tab shows the year end balance variances between the continuity schedule and that reported in the RRR.	4	Provide an explanation for the variances identified.
4 - Billing Determinant	This tab shows the billing determinants that will be used to allocate account balances and calculate rate riders.	5	Complete the billing determinant table. Note that columns O and P are generated when a utility indicates they have Class A customers in tab 2. Information in these columns are populated based on data from tab 5.1.
5 - Allocating Def-Var Balances	This tab allocates the DVA balance (except for CBR Class B if Class A customers exist).	6	Review the allocated balances to ensure the allocation is appropriate. Note that the allocations for Account 1589, Account 1580, sub-account CBR Class B will be determined after tabs 5.1 to 5.3a have been completed.
5.1 - Class A Data	This is a new tab that is to be completed if there were any Class A customers at any point during the period the GA balance accumulated. The tab also considers Class A/B transition customers. The data on this tab is used for the	7	This tab is generated when the utility checks in tab 2 that they have Class A customers during the period that the GA balance accumulated. Under #1, enter the year the Account 1589 GA balance was last disposed.
		8	Under #2a, indicate whether you had any customers that transitioned between Class A and B during the period the Account 1589 GA balance accumulated. If no, proceed to #3b in step 10. If yes, #2b and tab 5.2 will be generated. Proceed to #2b. Under #2b, indicate whether you had any customers that transitioned between Class A and B during the period the Account 1580, sub-account CBR Class B balance accumulated. If no, proceed to #3a in step 9. If yes, tab 5.3a will be generated. Proceed to #3a in step 9.

Consumption	purposes of determining the GA rate rider, CBR Class B rate rider (if applicable), as well as customer specific GA and CBR Class B charges for transition customers (if applicable).	9	Under #3a, enter the number of transition customers during the period the Account 1589 GA balance accumulated. A table will be generated based on the number of customers. Complete the table accordingly for each transition customer identified (i.e. kWh/kW for half year periods, and the customer class during the half year). This data will automatically be used in the GA balance and CBR Class B balance allocation to transition customers in tabs 5.2 and 5.3a, respectively. Each transition customer identified in tab 5.1, table 3a will be assigned a customer number and the number will correspond to the same transition customers populated in tabs 5.2 and 5.3a. The data in tab 5.1 will also be used in the calculation of billing determinants in the allocation of GA and CBR Class B balances to the rate classes, as applicable.
		10	Under #3b, enter the number of customers who were Class A customers during the entire period since the year the Account 1589 GA balance accumulated (i.e. did not transition between Class A and B during the period). A table will be generated based on the number of customers. Complete the table accordingly for each Class A customer identified. This data will be used in the calculation of billing determinants in the allocation of GA and CBR Class B balances to the rate classes, as applicable.
5.2 - GA Allocation	This tab has been revised. It allocates the GA balance to each transition customer for the period in which these customers were Class B customers and contributed to the GA balance (i.e. former Class B customers who contributed to the GA balance but are now Class A customers and former Class A customers who are now Class B customers contributing to the GA balance).	11	This tab is generated when the utility indicates that they have transition customers in tab 5.1, #2a during the period where the GA balance accumulated. In row 20, enter the total Class B consumption which equals to Non-RPP consumption less WMP consumption and consumption for Class A customers (who were Class A for partial and full year). The rest of the information in this tab will be auto-populated and will calculate the customer specific allocation of the GA balance to transition customers in the bottom table. All transition customers who are allocated a specific GA amount are not to be charged the general Non-RPP Class B GA rate rider as calculated in tab 6.
5.3 - CBR	This is a new tab that calculates the CBR Class B rate rider if there were Class A customers at any point during the period that the CBR Class B balance accumulated.	12	This tab is generated when the utility checks in tab 2 that they have Class A customers during the period that Account 1580, sub-account CBR Class B balance accumulated. Select one of two options pertaining to the years in which the CBR Class B balance accumulated, either 2015 and 2016, or 2016 only in cell B13. The rest of the information in the tab is auto-populated and will be used in the calculation of the CBR Class B rate rider calculated in tab 6.
5.3a - CBR_B Allocation	This is a new tab that allocates the CBR Class B balance to each transition customer for the period in which these customers were Class B customers and contributed to the CBR Class B balance (i.e. former Class B customers who contributed to the balance but are now Class A customers and former Class A customers who are now Class B contributing to the balance).	13	This tab is generated when the utility indicates that they have transition customers in tab 5.1, #2b during the period where the CBR Class B balance accumulated. In row 20, enter the total Class B consumption which equals to total consumption less WMP consumption and consumption for Class A customers (who were Class A for partial and full year). The rest of the information in this tab will be auto-populated and will calculate the customer specific allocation of the CBR Class B balance to transition customers in the bottom table. Note that the transition customers for the GA may be different than the transition customers for CBR Class B as this would depend on the period in which the GA and CBR Class B balances accumulated. All transition customers who are allocated a specific CBR Class B amount is not to be charged the general CBR Class B rate rider.
6 - Calculation of Def-Var RR	This tab calculates all the applicable DVA ate riders.	14	Enter the proposed rate rider recovery period if different than the default 12 month period. For each rate class of each rate rider, select whether the rate rider is to be calculated on a kWh/kW or number of customers basis. The rest of the information in the tab is auto-populated and the rate riders are calculated accordingly .
7 + 7.a GA Analysis	This is a new GA Analysis Workform that is to be completed.	15	Complete tab 7.a according to the instructions in tab 7.

Ontario Energy Board

2018 Deferral/Variance Account Workform

This continuity schedule must be completed for each account and sub-account that the utility has approved for use as at Dec. 31, 2016, regardless of whether disposition is being requested for the account. For all accounts, except for Account 1595, start inputting data from the year in which the GL balance was last disposed. For example, if in the 2017 rate application, DVA balances as at December 31, 2015 were approved for disposition, start the continuity schedule from 2015 by entering the approved closing 2014 balance in the Adjustment column under 2014. For each Account 1595 sub-account, start inputting data from the year the sub-account started to accumulate a balance (i.e. the vintage year). For example, Account 1595 (2014), data should be inputted starting in 2014 when the relevant balances approved for disposition was first transferred into Account 1595 (2014). The DVA continuity schedule currently starts from 2011, if a utility has an Account 1595 with a vintage year prior to 2011, then a separate schedule should be provided starting from the vintage year. For any new accounts that have never been disposed, start inputting data from the year the account was approved to be used.

Enter the number of utility specific Account 1508 sub-accounts that have been previously approved, regardless of whether disposition is being requested. If none, enter 1 and the generic sub-account will still be

Identify and name each sub-account and complete the continuity schedule in the line(s) generated in the continuity schedule. Indicate whether the sub-account is requested for

		2011										2012							
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-11	Transactions(1) Debit / (Credit) during 2011	OEB-Approved Disposition during 2011	Principal Adjustments(2) during 2011	Closing Principal Balance as of Dec-31-11	Opening Interest Amounts as of Jan-1-11	Interest Jan-1 to Dec-31-11	OEB-Approved Disposition during 2011	Interest Adjustments(1) during 2011	Closing Interest Amounts as of Dec-31-11	Opening Principal Amounts as of Jan-1-12	Transactions(1) Debit / (Credit) during 2012	OEB-Approved Disposition during 2012	Principal Adjustments(2) during 2012	Closing Principal Balance as of Dec-31-12	Opening Interest Amounts as of Jan-1-12	Interest Jan-1 to Dec-31-12	OEB-Approved Disposition during 2012
Group 1 Accounts																			
LV Variance Account	1550					$0					$0	$0				$0	$0		
Smart Metering Entity Charge Variance Account	1551																		
RSVA - Wholesale Market Service Charge[9]	1580	-$963,028	-$1,003,762	-$224,334		-$1,742,456	-$239,081	-$19,871	-$231,563		-$27,389	-$1,742,456	-$1,310,114	-$746,214		-$2,306,356	-$27,389	-$28,921	-$14,479
Variance WMS – Sub-account CBR Class A[9]	1580																		
Variance WMS – Sub-account CBR Class B[9]	1580																		
RSVA - Retail Transmission Network Charge	1584	$419,554	-$182,276	$147,549		$89,729	-$36,837	$5,732	-$37,468		$6,363	$89,729	-$285,902	$272,636		-$468,809	$6,363	-$330	$5,331
RSVA - Retail Transmission Connection Charge	1586					$0					$0	$0				$0	$0		
RSVA - Power (excluding Global Adjustment)[12]	1588	-$1,247,547	-$1,430,318	-$1,060,296		-$1,617,569	-$162,685	-$39,465	-$154,036		-$48,114	-$1,617,569	-$318,550	-$195,832		-$1,740,287	-$48,114	-$38,800	-$3,669
RSVA - Global Adjustment [12]	1589	$288,635	$394,444	$538,679		$144,400	$4,155	$14,007	$2,250		$15,912	$144,400	-$69,206	-$248,139		$323,333	$15,912	$19,328	-$4,901
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595					$0					$0	$0				$0	$0		
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	-$944,748	$723,746			-$221,002	$137,669	-$5,773			$131,896	-$221,002				-$221,002	$131,896	-$3,249	
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595		$542,644	$1,020,945		-$478,301	-$2,585				-$2,585	-$478,301	$441,467			-$36,834	-$2,585	$4,161	
Disposition and Recovery/Refund of Regulatory Balances (2012)[7]	1595					$0					$0	$0	$469,784	$875,129		-$405,345	$0	-$6,720	-$2,832
Disposition and Recovery/Refund of Regulatory Balances (2013)[7]	1595					$0					$0	$0				$0	$0		
Disposition and Recovery/Refund of Regulatory Balances (2014)[7]	1595					$0					$0	$0				$0	$0		
Disposition and Recovery/Refund of Regulatory Balances (2015)[7]	1595					$0					$0	$0				$0	$0		
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595					$0					$0	$0				$0	$0		
Not to be disposed of until a year after rate rider has expired and that balance has been audited																			
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$2,447,134	-$955,522	$422,543	$0	-$3,825,199	-$299,364	-$45,370	-$420,817	$0	$76,083	-$3,825,199	-$1,072,521	-$42,420	$0	-$4,855,300	$76,083	-$54,531	-$20,550
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$2,735,769	-$1,349,966	-$116,136	$0	-$3,969,599	-$303,519	-$59,377	-$423,067	$0	$60,171	-$3,969,599	-$1,003,315	$205,719	$0	-$5,178,633	$60,171	-$73,859	-$15,649
RSVA - Global Adjustment 12	**1589**	$288,635	$394,444	$538,679	$0	$144,400	$4,155	$14,007	$2,250	$0	$15,912	$144,400	-$69,206	-$248,139	$0	$323,333	$15,912	$19,328	-$4,901
Group 2 Accounts																			
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508					$0					$0	$0				$0	$0		
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508					$0					$0	$0				$0	$0		
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508					$0					$0	$0				$0	$0		
Other Regulatory Assets - Sub-Account - Other	1508					$0					$0	$0				$0	$0		
Retail Cost Variance Account - Retail	1518	-$351,582	-$36,541			-$388,123	-$37,392	-$5,388			-$42,780	-$388,123	-$31,603			-$419,726	-$42,780	-$5,923	
Misc. Deferred Debits	1525					$0					$0	$0				$0	$0		
Retail Cost Variance Account - STR	1548	$144,793	$16,348			$161,141	$11,457	$2,256			$13,713	$161,141	$5,646			$166,787	$13,713	$2,449	
Board-Approved CDM Variance Account	1567					$0					$0	$0				$0	$0		
Extra-Ordinary Event Costs	1572					$0					$0	$0				$0	$0		
Deferred Rate Impact Amounts	1574					$0					$0	$0				$0	$0		
RSVA - One-time	1582					$0					$0	$0				$0	$0		
Other Deferred Credits	2425	-$243,686				-$243,686	-$15,064	-$3,582			-$18,646	-$243,686				-$243,686	-$18,646	-$3,582	
Group 2 Sub-Total			-$20,193	$0	$0	-$470,668	-$40,999	-$6,714	$0	$0	-$47,713	-$470,668	-$25,957	$0	$0	-$496,625	-$47,713	-$7,056	$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592					$0					$0	$0				$0	$0		
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592					$0					$0	$0				$0	$0		
Total of Group 1 and Group 2 Accounts (including 1592)		-$2,447,134	-$975,715	$422,543	$0	-$4,295,867	-$340,363	-$52,084	-$420,817	$0	$28,370	-$4,295,867	-$1,098,478	-$42,420	$0	-$5,351,925	$28,370	-$61,587	-$20,550
LRAM Variance Account[11]	**1568**					$0					$0	$0				$0	$0		
Total including Account 1568			-$975,715	$422,543	$0	-$4,295,867	-$340,363	-$52,084	-$420,817	$0	$28,370	-$4,295,867	-$1,098,478	-$42,420	$0	-$5,351,925	$28,370	-$61,587	-$20,550
Renewable Generation Connection Capital Deferral Account[8]	1531					$0					$0	$0				$0	$0		
Renewable Generation Connection OM&A Deferral Account[8]	1532					$0					$0	$0				$0	$0		
Renewable Generation Connection Funding Adder Deferral Account	1533					$0					$0	$0				$0	$0		
Smart Grid Capital Deferral Account	1534					$0					$0	$0				$0	$0		
Smart Grid OM&A Deferral Account	1535					$0					$0	$0				$0	$0		
Smart Grid Funding Adder Deferral Account	1536					$0					$0	$0				$0	$0		
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[4]	1555	$5,306,500	-$80,543			$5,225,957	$22,912	$56,627			$79,539	$5,225,957	-$5,225,957			$0	$79,539	-$79,539	
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[4]	1555	-$1,315,245	-$659,068			-$1,974,313					$0	-$1,974,313	$1,974,313			$0	$0		
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[4]	1555					$0					$0	$0				$0	$0		
Smart Meter OM&A Variance[4]	1556	$706,544	$798,777			$1,505,321	$2,068	$12,243			$14,311	$1,505,321	-$1,505,321			$0	$14,311	-$14,311	
Meter Cost Deferral Account (MIST Meters)[10]	1557																		
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575					$0						$0				$0			
Accounting Changes Under CGAAP Balance + Return Component[5]	1576											$0	-$335,332			-$335,332			

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This continuity schedule must be completed for each account and sub-account that the utilit
from the year in which the GL balance was last disposed. For example, if in the 2017 rate ap
Adjustment column under 2014. For each Account 1595 sub-account, start inputting data fro
balances approved for disposition was first transferred into Account 1595 (2014). The DVA c
vintage year. For any new accounts that have never been disposed, start inputting data from

				2013										2014								
Account Descriptions	Account Number	Interest Adjustments(2) during 2012	Closing Interest Amounts as of Dec-31-12	Opening Principal Amounts as of Jan-1-13	Transactions(1) Debit / (Credit) during 2013	OEB-Approved Disposition during 2013	Principal Adjustments(2) during 2013	Closing Principal Balance as of Dec-31-13	Opening Interest Amounts as of Jan-1-13	Interest Jan-1 to Dec-31-13	OEB-Approved Disposition during 2013	Interest Adjustments(2) during 2013	Closing Interest Amounts as of Dec-31-13	Opening Principal Amounts as of Jan-1-14	Transactions(1) Debit / (Credit) during 2014	OEB-Approved Disposition during 2014	Principal Adjustments(2) during 2014	Closing Principal Balance as of Dec-31-14	Opening Interest Amounts as of Jan-1-14	Interest Jan-1 to Dec-31-14	OEB-Approved Disposition during 2014	Interest Adjustments(2) during 2014
Group 1 Accounts																						
LV Variance Account	1550		$0	$0				$0	$0				$0	$0				$0	$0			
Smart Metering Entity Charge Variance Account	1551			$0	$23,661			$23,661	$0	$230			$230	$23,661	-$643			$23,018	$230	$640		
RSVA - Wholesale Market Service Charge[9]	1580		-$41,831	-$2,306,356	-$852,882	-$996,241		-$2,162,997	-$41,831	-$36,134	-$34,877		-$43,088	-$2,162,997	$1,081,213			-$1,081,784	-$43,088	$15,451		
Variance WMS – Sub-account CBR Class A[9]	1580																					
Variance WMS – Sub-account CBR Class B[9]	1580																					
RSVA - Retail Transmission Network Charge	1584		$702	-$468,809	-$399	-$182,906		-$286,302	$702	-$4,948	-$3,001		-$1,245	-$286,302	$595,420			$309,118	-$1,245	$3,625		
RSVA - Retail Transmission Connection Charge	1586		$0	$0				$0	$0				$0	$0				$0	$0			
RSVA - Power (excluding Global Adjustment)[12]	1588		-$83,245	-$1,740,287	$231,227	-$1,421,736		-$87,324	-$83,245	-$25,631	-$75,796		-$33,080	-$87,324	$1,007,835			$920,511	-$33,080	$24,591		
RSVA - Global Adjustment [12]	1589		$40,141	$323,333	$210,978	$392,539		$141,772	$40,141	$23,247	$29,468		$33,920	$141,772	$1,159,476			$1,301,248	$33,920	$2,509		
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595		$0	$0				$0	$0				$0	$0				$0	$0			
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595		$128,647	-$221,002		-$221,002		$0	$128,647	-$1,624	$127,023		$0	$0				$0	$0			
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595		$1,576	-$36,834				-$36,834	$1,576	$5,654			$7,230	-$36,834		-$36,834		$0	$7,230	$1,415	$1,125	-$7,520
Disposition and Recovery/Refund of Regulatory Balances (2012)[7]	1595		-$3,888	-$405,345	$381,437			-$23,908	-$3,888	-$1,790			-$5,678	-$23,908	$352			-$23,556	-$5,678	-$350		
Disposition and Recovery/Refund of Regulatory Balances (2013)[7]	1595		$0	$0	$1,042,900	$2,525,100		-$1,482,200	$0	-$12,998	$113,087		-$126,085	-$1,482,200	$1,642,156			$159,956	-$126,085	-$3,837		
Disposition and Recovery/Refund of Regulatory Balances (2014)[7]	1595		$0	$0				$0	$0				$0	$0	-$1,026,858			-$1,026,858	$0	-$54,096		
Disposition and Recovery/Refund of Regulatory Balances (2015)[7]	1595		$0	$0				$0	$0				$0	$0				$0	$0			
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595		$0	$0				$0	$0				$0	$0				$0	$0			
Not to be disposed of until a year after rate rider has expired and that balance has been audited																						
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$42,102	-$4,855,300	$1,036,922	$95,754	$0	-$3,914,132	$42,102	-$53,994	$155,904	$0	-$167,796	-$3,914,132	$4,458,951	-$36,834	$0	$581,653	-$167,796	-$10,052	$1,125	-$7,520
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	$1,961	-$5,178,633	$825,944	-$296,785	$0	-$4,055,904	$1,961	-$77,241	$126,436	$0	-$201,716	-$4,055,904	$3,299,475	-$36,834	$0	-$719,595	-$201,716	-$12,561	$1,125	-$7,520
RSVA - Global Adjustment 12	**1589**	$0	$40,141	$323,333	$210,978	$392,539	$0	$141,772	$40,141	$23,247	$29,468	$0	$33,920	$141,772	$1,159,476	$0	$0	$1,301,248	$33,920	$2,509	$0	$0
Group 2 Accounts																						
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508		$0	$0				$0	$0				$0	$0				$0	$0			
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508		$0	$0				$0	$0				$0	$0				$0	$0			
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508		$0	$0				$0	$0				$0	$0				$0	$0			
Other Regulatory Assets - Sub-Account - Other	1508		$0	$0	-$52,200			-$52,200	$0				$0	-$52,200	-$104,400			-$156,600	$0			
Retail Cost Variance Account - Retail	1518		-$48,703	-$419,726	-$29,923	-$388,122		-$61,527	-$48,703	-$3,999	-$51,337		-$1,365	-$61,527	-$26,880			-$88,407	-$1,365	-$1,084		
Misc. Deferred Debits	1525		$0	$0				$0	$0				$0	$0				$0	$0			
Retail Cost Variance Account - STR	1548		$16,162	$166,787	$29,041	$161,142		$34,686	$16,162	$1,855	$17,265		$752	$34,686	$18,919			$53,605	$752	$665		
Board-Approved CDM Variance Account	1567		$0	$0				$0	$0				$0	$0				$0	$0			
Extra-Ordinary Event Costs	1572		$0	$0				$0	$0				$0	$0				$0	$0			
Deferred Rate Impact Amounts	1574		$0	$0				$0	$0				$0	$0				$0	$0			
RSVA - One-time	1582		$0	$0				$0	$0				$0	$0				$0	$0			
Other Deferred Credits	2425		-$22,228	-$243,686	$52,200	-$243,686		$52,200	-$22,228	-$1,791	-$24,019		$0	$52,200	$104,400			$156,600	$0			
Group 2 Sub-Total		$0	-$54,769	-$496,625	-$882	-$470,666	$0	-$26,841	-$54,769	-$3,935	-$58,091	$0	-$613	-$26,841	-$7,961	$0	$0	-$34,802	-$613	-$419	$0	$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592		$0	$0				$0	$0				$0	$0				$0	$0			
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592		$0	$0				$0	$0				$0	$0				$0	$0			
Total of Group 1 and Group 2 Accounts (including 1592)		$0	-$12,667	-$5,351,925	$1,036,040	-$374,912	$0	-$3,940,973	-$12,667	-$57,929	$97,813	$0	-$168,409	-$3,940,973	$4,450,990	-$36,834	$0	$546,851	-$168,409	-$10,471	$1,125	-$7,520
LRAM Variance Account[11]	**1568**		$0	$0	$79,055			$79,055	$0	$2,044			$2,044	$79,055	-$45,276			$33,779	$2,044	$936		
Total including Account 1568		$0	-$12,667	-$5,351,925	$1,115,095	-$374,912	$0	-$3,861,918	-$12,667	-$55,885	$97,813	$0	-$166,365	-$3,861,918	$4,405,714	-$36,834	$0	$580,630	-$166,365	-$9,535	$1,125	-$7,520
Renewable Generation Connection Capital Deferral Account[8]	1531		$0	$0				$0	$0				$0	$0				$0	$0			
Renewable Generation Connection OM&A Deferral Account[8]	1532		$0	$0				$0	$0				$0	$0				$0	$0			
Renewable Generation Connection Funding Adder Deferral Account	1533		$0	$0				$0	$0				$0	$0				$0	$0			
Smart Grid Capital Deferral Account	1534		$0	$0				$0	$0				$0	$0				$0	$0			
Smart Grid OM&A Deferral Account	1535		$0	$0				$0	$0				$0	$0				$0	$0			
Smart Grid Funding Adder Deferral Account	1536		$0	$0				$0	$0				$0	$0				$0	$0			
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[4]	1555		$0	$0				$0	$0				$0	$0				$0	$0			
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[4]	1555		$0	$0	$710,860			$710,860	$0	$6,785			$6,785	$710,860	-$716,343			-$5,483	$6,785	$2,713		
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[4]	1555		$0	$0				$0	$0				$0	$0				$0	$0			
Smart Meter OM&A Variance[4]	1556		$0	$0				$0	$0				$0	$0				$0	$0			
Meter Cost Deferral Account (MIST Meters)[10]	1557													$0				$0	$0			
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575			$0				$0						$0				$0				
Accounting Changes Under CGAAP Balance + Return Component[5]	1576			-$335,332	$116,706			-$218,626						-$218,626	$72,876			-$145,750				

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This continuity schedule must be completed for each account and sub-account that the utilit
from the year in which the GL balance was last disposed. For example, if in the 2017 rate ap
Adjustment column under 2014. For each Account 1595 sub-account, start inputting data fro
balances approved for disposition was first transferred into Account 1595 (2014). The DVA c
vintage year. For any new accounts that have never been disposed, start inputting data from

			2015										2016									
Account Descriptions	Account Number	Closing Interest Amounts as of Dec-31-14	Opening Principal Amounts as of Jan-1-15	Transactions(1) Debit / (Credit) during 2015	OEB-Approved Disposition during 2015	Principal Adjustments(2) during 2015	Closing Principal Balance as of Dec-31-15	Opening Interest Amounts as of Jan-1-15	Interest Jan-1 to Dec-31-15	OEB-Approved Disposition during 2015	Interest Adjustments(2) during 2015	Closing Interest Amounts as of Dec-31-15	Opening Principal Amounts as of Jan-1-16	Transactions(1) Debit / (Credit) during 2016	OEB-Approved Disposition during 2016	Principal Adjustments(2) during 2016	Closing Principal Balance as of Dec-31-16	Opening Interest Amounts as of Jan-1-16	Interest Jan-1 to Dec-31-16	OEB-Approved Disposition during 2016	Interest Adjustments(2) during 2016	Closing Interest Amounts as of Dec-31-16
Group 1 Accounts																						
LV Variance Account	1550	$0	$0				$0	$0				$0	$0				$0	$0				$0
Smart Metering Entity Charge Variance Account	1551	$870	$23,018	-$124			$22,894	$870	-$18			$852	$22,894	$10,945			$33,839	$852	$576			$1,428
RSVA - Wholesale Market Service Charge[9]	1580	-$27,637	-$1,081,784	-$1,519,861			-$2,601,645	-$27,637	-$18,618			-$46,255	-$2,601,645	-$844,433	-$1,081,784		-$2,364,294	-$46,255	-$27,016	-$39,638		-$33,633
Variance WMS – Sub-account CBR Class A[9]	1580		$0				$0	$0				$0	$0				$0	$0				$0
Variance WMS – Sub-account CBR Class B[9]	1580		$0				$0	$0				$0	$0				$0	$0				$0
RSVA - Retail Transmission Network Charge	1584	$2,380	$309,118	-$77,845			$231,273	$2,380	$4,946			$7,326	$231,273	-$20,198	$309,118		-$98,043	$7,326	-$517	$5,787		$1,022
RSVA - Retail Transmission Connection Charge	1586	$0	$0				$0	$0				$0	$0				$0	$0				$0
RSVA - Power (excluding Global Adjustment)[12]	1588	-$8,489	$920,511	-$5,012,590			-$4,092,079	-$8,489	-$6,799			-$15,288	-$4,092,079	$4,398,272	$920,509		-$614,316	-$15,288	$25,791	$1,605		$8,898
RSVA - Global Adjustment [12]	1589	$36,429	$1,301,248	$177,382			$1,478,630	$36,429	$30,661			$67,090	$1,478,630	-$103,639	$1,301,248		$73,743	$67,090	$27,142	$50,876		$43,356
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$0	$0				$0	$0				$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$0	$0				$0	$0				$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595	$0	$0				$0	$0				$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2012)[7]	1595	-$6,028	-$23,556	-$663			-$24,219	-$6,028	-$297			-$6,325	-$24,219	$30,635			$6,416	-$6,325	-$89			-$6,414
Disposition and Recovery/Refund of Regulatory Balances (2013)[7]	1595	-$129,922	$159,956	-$9,872			$150,084	-$129,922	$1,823			-$128,099	$150,084	-$22,537			$127,547	-$128,099	$9,976			-$118,123
Disposition and Recovery/Refund of Regulatory Balances (2014)[7]	1595	-$54,096	-$1,026,858	$1,026,308			-$550	-$54,096	-$3,756			-$57,852	-$550	-$640			-$1,190	-$57,852	-$10			-$57,862
Disposition and Recovery/Refund of Regulatory Balances (2015)[7]	1595	$0	$0				$0	$0				$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$0	$0				$0	$0				$0	$0	$735,583			$735,583	$0	-$116,319			-$116,319
Not to be disposed of until a year after rate rider has expired and that balance has been audited																						
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$186,493	$581,653	-$5,417,265	$0	$0	-$4,835,612	-$186,493	$7,942	$0	$0	-$178,551	-$4,835,612	$4,183,988	$1,449,091	$0	-$2,100,715	-$178,551	-$80,466	$18,630	$0	-$277,647
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$222,922	-$719,595	-$5,594,647	$0	$0	-$6,314,242	-$222,922	-$22,719	$0	$0	-$245,641	-$6,314,242	$4,287,627	$147,843	$0	-$2,174,458	-$245,641	-$107,608	-$32,246	$0	-$321,003
RSVA - Global Adjustment 12	**1589**	$36,429	$1,301,248	$177,382	$0	$0	$1,478,630	$36,429	$30,661	$0	$0	$67,090	$1,478,630	-$103,639	$1,301,248	$0	$73,743	$67,090	$27,142	$50,876	$0	$43,356
Group 2 Accounts																						
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0	$0				$0	$0				$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0	$0				$0	$0				$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508	$0	$0				$0	$0				$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Other	1508	$0	-$156,600	-$104,400			-$261,000	$0				$0	-$261,000	-$104,400			-$365,400	$0				$0
Retail Cost Variance Account - Retail	1518	-$2,449	-$88,407	-$27,321			-$115,728	-$2,449	-$1,192			-$3,641	-$115,728	-$23,850			-$139,578	-$3,641	-$1,397			-$5,038
Misc. Deferred Debits	1525	$0	$0				$0	$0				$0	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$1,417	$53,605	$12,745			$66,350	$1,417	$701			$2,118	$66,350	$11,856			$78,206	$2,118	$782			$2,900
Board-Approved CDM Variance Account	1567	$0	$0				$0	$0				$0	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$0	$0				$0	$0				$0	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0	$0				$0	$0				$0	$0				$0	$0				$0
RSVA - One-time	1582	$0	$0				$0	$0				$0	$0				$0	$0				$0
Other Deferred Credits	2425	$0	$156,600	$104,400			$261,000	$0				$0	$261,000	$104,400			$365,400	$0				$0
Group 2 Sub-Total		-$1,032	-$34,802	-$14,576	$0	$0	-$49,378	-$1,032	-$491	$0	$0	-$1,523	-$49,378	-$11,994	$0	$0	-$61,372	-$1,523	-$615	$0	$0	-$2,138
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0	$0				$0	$0				$0	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$0	$0				$0	$0				$0	$0				$0	$0				$0
Total of Group 1 and Group 2 Accounts (including 1592)		-$187,525	$546,851	-$5,431,841	$0	$0	-$4,884,990	-$187,525	$7,451	$0	$0	-$180,074	-$4,884,990	$4,171,994	$1,449,091	$0	-$2,162,087	-$180,074	-$81,081	$18,630	$0	-$279,785
LRAM Variance Account[11]	**1568**	$2,980	$33,779	-$47,147			-$13,368	$2,980	$34			$3,014	-$13,368	-$23			-$13,391	$3,014	-$125			$2,889
Total including Account 1568		-$184,545	$580,630	-$5,478,988	$0	$0	-$4,898,358	-$184,545	$7,485	$0	$0	-$177,060	-$4,898,358	$4,171,971	$1,449,091	$0	-$2,175,478	-$177,060	-$81,206	$18,630	$0	-$276,896
Renewable Generation Connection Capital Deferral Account[8]	1531	$0	$0				$0	$0				$0	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral Account[8]	1532	$0	$0				$0	$0				$0	$0				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533	$0	$0				$0	$0				$0	$0				$0	$0				$0
Smart Grid Capital Deferral Account	1534	$0	$0				$0	$0				$0	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0	$0				$0	$0				$0	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0	$0				$0	$0				$0	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[4]	1555	$0	$0				$0	$0				$0	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[4]	1555	$9,498	-$5,483	-$42			-$5,525	$9,498	-$65			$9,433	-$5,525				-$5,525	$9,433	-$61			$9,372
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[4]	1555	$0	$0				$0	$0				$0	$0				$0	$0				$0
Smart Meter OM&A Variance[4]	1556	$0	$0				$0	$0				$0	$0				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[10]	1557	$0	$0				$0	$0				$0	$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575		$0				$0						$0				$0					
Accounting Changes Under CGAAP Balance + Return Component[5]	1576		-$145,750	$72,876			-$72,874						-$72,874	$72,876			$2					

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eferral/Variance Account Workforn

If you had any Class A customers at any point during the period that the Account 1589 GA balance accumulated (i.e. from the year the balance was last disposed to 2016), check off the checkbox ☐

If you had Class A customer(s) during this period, Tab 5.1 will be generated and applicants must complete the information pertaining to Class A customers.

This continuity schedule must be completed for each account and sub-account that the utilit from the year in which the GL balance was last disposed. For example, if in the 2017 rate ap Adjustment column under 2014. For each Account 1595 sub-account, start inputting data fro balances approved for disposition was first transferred into Account 1595 (2014). The DVA c vintage year. For any new accounts that have never been disposed, start inputting data fron

		2017				Projected Interest on Dec-31-16 Balances					2.1.7 RRR	
Account Descriptions	Account Number	Principal Disposition during 2017 - instructed by OEB	Interest Disposition during 2017 - instructed by OEB	Closing Principal Balances as of Dec 31-16 Adjusted for Dispositions during 2017	Closing Interest Balances as of Dec 31-16 Adjusted for Dispositions during 2017	Projected Interest from Jan 1, 2017 to December 31, 2017 on Dec 31 -16 balance adjusted for disposition during 2017 (6)	Projected Interest from January 1, 2018 to April 30, 2018 on Dec 31 -16 balance adjusted for disposition during 2017 (6)	Total Interest		Total Claim	As of Dec 31-16	Variance RRR vs. 2016 Balance (Principal + Interest)
Group 1 Accounts												
LV Variance Account	1550			$0	$0	$0	$0	$0		$0.00		$0
Smart Metering Entity Charge Variance Account	1551			$33,839	$1,428	$406	$169	$2,003		$35,842.26	$35,268	$1
RSVA - Wholesale Market Service Charge[9]	1580			-$2,364,294	-$33,633	-$28,372	-$11,821	-$73,826		-$2,438,120.00	-$2,397,926	$1
Variance WMS – Sub-account CBR Class A[9]	1580			$0	$0	$0	$0	$0		$0.00		$0
Variance WMS – Sub-account CBR Class B[9]	1580			$0	$0	$0	$0	$0		$0.00		$0
RSVA - Retail Transmission Network Charge	1584			-$98,043	$1,022	-$1,177	-$490	-$645		-$98,687.73	-$97,020	$1
RSVA - Retail Transmission Connection Charge	1586			$0	$0	$0	$0	$0		$0.00		$0
RSVA - Power (excluding Global Adjustment)[12]	1588			-$614,316	$8,898	-$7,372	-$3,072	-$1,545		-$615,861.37	-$605,420	-$2
RSVA - Global Adjustment [12]	1589			$73,743	$43,356	$885	$369	$44,610		$118,352.63	$117,099	-$0
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595			$0	$0	$0	$0	$0	☐ Check to Dispose of Account	$0.00		$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595			$0	$0	$0	$0	$0	☐ Check to Dispose of Account	$0.00		$0
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595			$0	$0	$0	$0	$0	☐ Check to Dispose of Account	$0.00		$0
Disposition and Recovery/Refund of Regulatory Balances (2012)[7]	1595			$6,416	-$6,414	$77	$32	-$6,305	☐ Check to Dispose of Account	$0.00	$1	-$1
Disposition and Recovery/Refund of Regulatory Balances (2013)[7]	1595			$127,547	-$118,123	$1,531	$638	-$115,955	☐ Check to Dispose of Account	$0.00	$9,426	$2
Disposition and Recovery/Refund of Regulatory Balances (2014)[7]	1595			-$1,190	-$57,862	-$14	-$6	-$57,882	☑ Check to Dispose of Account	-$59,072.23	-$59,051	$1
Disposition and Recovery/Refund of Regulatory Balances (2015)[7]	1595			$0	$0	$0	$0	$0	☐ Check to Dispose of Account	$0.00		$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595			$735,583	-$116,319	$8,827	$3,678	-$103,814	☐ Check to Dispose of Account	$0.00	$619,264	-$0
Not to be disposed of until a year after rate rider has expired and that balance has been audited												
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$0	-$2,100,715	-$277,647	-$25,209	-$10,504	-$313,359		-$3,057,546.44	-$2,378,360	$2
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	$0	-$2,174,458	-$321,003	-$26,093	-$10,872	-$357,969		-$3,175,899.07	-$2,495,458	$3
RSVA - Global Adjustment 12	**1589**	$0	$0	$73,743	$43,356	$885	$369	$44,610		$118,352.63	$117,099	-$0
Group 2 Accounts												
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508			$0	$0	$0	$0	$0		$0.00		$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508			$0	$0	$0	$0	$0		$0.00		$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508			$0	$0	$0	$0	$0		$0.00		$0
Other Regulatory Assets - Sub-Account - Other	1508			-$365,400	$0	-$4,385	-$1,827	-$6,212	☐ Check to Dispose of Account	$0.00	-$365,400	$0
Retail Cost Variance Account - Retail	1518			-$139,578	-$5,038	-$1,675	-$698	-$7,411		-$146,988.83	-$144,622	-$6
Misc. Deferred Debits	1525			$0	$0	$0	$0	$0	☐ Check to Dispose of Account	$0.00		$0
Retail Cost Variance Account - STR	1548			$78,206	$2,900	$938	$391	$4,230		$82,435.50	$81,105	-$1
Board-Approved CDM Variance Account	1567			$0	$0	$0	$0	$0		$0.00		$0
Extra-Ordinary Event Costs	1572			$0	$0	$0	$0	$0		$0.00		$0
Deferred Rate Impact Amounts	1574			$0	$0	$0	$0	$0		$0.00		$0
RSVA - One-time	1582			$0	$0	$0	$0	$0		$0.00		$0
Other Deferred Credits	2425			$365,400	$0	$4,385	$1,827	$6,212	☐ Check to Dispose of Account	$0.00	$365,400	$0
Group 2 Sub-Total		$0	$0	-$61,372	-$2,138	-$736	-$307	-$3,181		-$64,553.32	-$63,517	-$7
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592			$0	$0	$0	$0	$0		$0.00		$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592			$0	$0	$0	$0	$0		$0.00		$0
Total of Group 1 and Group 2 Accounts (including 1592)		$0	$0	-$2,162,087	-$279,785	-$25,945	-$10,810	-$316,540		-$3,122,099.76	-$2,441,877	-$5
LRAM Variance Account[11]	**1568**	-$476,485	-$9,693	$463,095	$12,582			$12,582		$475,676.53	-$10,502	-$1
Total including Account 1568		-$476,485	-$9,693	-$1,698,992	-$267,203	-$25,945	-$10,810	-$303,958		-$2,646,423.23	-$2,452,379	-$5
Renewable Generation Connection Capital Deferral Account[8]	1531			$0	$0	$0	$0	$0		$0.00		$0
Renewable Generation Connection OM&A Deferral Account[8]	1532			$0	$0	$0	$0	$0		$0.00		$0
Renewable Generation Connection Funding Adder Deferral Account	1533			$0	$0	$0	$0	$0		$0.00		$0
Smart Grid Capital Deferral Account	1534			$0	$0	$0	$0	$0		$0.00		$0
Smart Grid OM&A Deferral Account	1535			$0	$0	$0	$0	$0		$0.00		$0
Smart Grid Funding Adder Deferral Account	1536			$0	$0	$0	$0	$0		$0.00		$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[4]	1555			$0	$0	$0	$0	$0		$0.00		$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[4]	1555			-$5,525	$9,372	-$66	-$28	$9,278		$3,753.33	$3,847	-$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[4]	1555			$0	$0	$0	$0	$0		$0.00		$0
Smart Meter OM&A Variance[4]	1556			$0	$0	$0	$0	$0		$0.00		$0
Meter Cost Deferral Account (MIST Meters)[10]	1557			$0	$0	$0	$0	$0		$0.00		$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575			$0					☐ Check to Dispose of Account	$0.00		$0
Accounting Changes Under CGAAP Balance + Return Component[5]	1576			$2					☐ Check to Dispose of Account	$0.00	$2	$0

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2018 Deferral/Variance Account Workform

Accounts that produced a variance on the continuity schedule are listed below.
Please provide a detailed explanation for each variance below.

Account Descriptions	Account Number	Variance RRR vs. 2016 Balance (Principal + Interest)	Explanation
Smart Metering Entity Charge Variance Account	1551	$ 1.00	
RSVA - Wholesale Market Service Charge9	1580	$ 1.00	
RSVA - Retail Transmission Network Charge	1584	$ 1.00	
RSVA - Power (excluding Global Adjustment)12	1588	$ (2.00)	
RSVA - Global Adjustment 12	1589	$ (0.36)	
Disposition and Recovery/Refund of Regulatory Balances (2012)7	1595	$ (1.00)	
Disposition and Recovery/Refund of Regulatory Balances (2013)7	1595	$ 1.94	
Disposition and Recovery/Refund of Regulatory Balances (2014)7	1595	$ 1.08	
Disposition and Recovery/Refund of Regulatory Balances (2016)7	1595	$ (0.17)	
Retail Cost Variance Account - Retail	1518	$ (6.00)	
Retail Cost Variance Account - STR	1548	$ (1.00)	

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2018 Deferral/Variance Account Workform

In the green shaded cells, enter the data related to the **proposed** load forecast. Do not enter data for the MicroFit class.

			A		B			C		D=A-C	
Rate Class (Enter Rate Classes in cells below as they appear on your current tariff of rates and charges)	**Units**	**# of Customers**	**Total Metered kWh ^{4}**	**Total Metered kW ^{4}**	**Metered kWh for Non-RPP Customers $^{4, 5}$**	**Metered kW for Non-RPP Customers $^{4, 5}$**	**Distribution Revenue**	**Metered kWh for Wholesale Market Participants (WMP) ^{4}**	**Metered kW for Wholesale Market Participants (WMP) ^{4}**	**Total Metered kWh less WMP consumption *(if applicable)***	**Total Metered kW less WMP consumption *(if applicable)***
RESIDENTIAL	kWh	29,789	296,393,596	-	13,130,236		9,084,381			296,393,596	-
GENERAL SERVICE LESS THAN 50 KW	kWh	3,443	94,320,130	-	7,507,882		2,640,479			94,320,130	-
GENERAL SERVICE 50 TO 4,999 KW	kW	353	248,349,153	624,500	158,670,274	398,993	3,797,584			248,349,153	624,500
UNMETERED SCATTERED LOAD	kWh	23	1,176,822	-			39,984			1,176,822	-
SENTINEL LIGHTING	kW	348	218,403	616			29,086			218,403	616
STREET LIGHTING	kW	8,070	2,415,793	7,076	2,353,224	6,893	420,382			2,415,793	7,076
										-	-
										-	-
										-	-
										-	-
										-	-
										-	-
										-	-
										-	-
										-	-
										-	-
										-	-
										-	-
										-	-
										-	-
Total		**42,026**	**642,873,897**	**632,192**	**181,661,616**	**405,886**	**$ 16,011,896**	**-**	**-**	**642,873,897**	**632,192**

[1] Account 1595 sub-accounts are to be allocated to rate classes in proportion to the recovery share as established when rate riders were implemented.

[2] The proportion of customers for the Residential and GS<50 Classes will be used to allocate Account 1551.

F =B-C-E (deduct E if applicable)										
Non-RPP Metered Consumption for Current Class B Customers (Non-RPP Consumption excluding WMP, Class A and Transition Customers' Consumption	**1595 Recovery Share Proportion (2009) [1]**	**1595 Recovery Share Proportion (2010) [1]**	**1595 Recovery Share Proportion (2011) [1]**	**1595 Recovery Share Proportion (2012) [1]**	**1595 Recovery Share Proportion (2013) [1]**	**1595 Recovery Share Proportion (2014) [1]**	**1595 Recovery Share Proportion (2015) [1]**	**1595 Recovery Share Proportion (2016) [1]**	**1568 LRAM Variance Account Class Allocation[3] ($ amounts)**	**Number of Customers for Residential and GS<50 classes[2]**
13,130,236						48%		45%	67,426	29,620
7,507,882						14%		14%	264,755	3,414
158,670,274						37%		39%	84,638	
-						0%		0%	(1,450)	
-						0%		0%	(1,091)	
2,353,224						1%		1%	61,399	
-										
-										
-										
-										
-										
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-										
-										
-										
-										
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-										
-										
-										
181,661,616	**0%**	**0%**	**0%**	**0%**	**0%**	**100%**	**0%**	**100%**	**$ 475,677**	
								Balance as per Sheet 2	$ 475,677	
								Variance	$ 0	

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2018 Deferral/Variance Account Workform

		Amounts from Sheet 2	Allocator	RESIDENTIAL	GENERAL SERVICE LESS THAN 50 KW	GENERAL SERVICE 50 TO 4,999 KW	UNMETERED SCATTERED LOAD	SENTINEL LIGHTING	STREET LIGHTING	
LV Variance Account	1550	0	kWh	0	0	0	0	0	0	0
Smart Metering Entity Charge Variance Account	1551	35,842	# of Customers	32,129	3,714	0	0	0	0	0
RSVA - Wholesale Market Service Charge	1580	(2,438,120)	kWh	(1,124,082)	(357,712)	(941,872)	(4,463)	(828)	(9,162)	0
RSVA - Retail Transmission Network Charge	1584	(98,688)	kWh	(45,499)	(14,479)	(38,124)	(181)	(34)	(371)	0
RSVA - Retail Transmission Connection Charge	1586	0	kWh	0	0	0	0	0	0	0
RSVA - Power (excluding Global Adjustment)	1588	(615,861)	kWh	(283,940)	(90,357)	(237,914)	(1,127)	(209)	(2,314)	0
RSVA - Global Adjustment	1589	118,353	Non-RPP kWh	8,554	4,891	103,374	0	0	1,533	0
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	0	%	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	0	%	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2011)	1595	0	%	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	0	%	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	0	%	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	(59,072)	%	(28,133)	(8,459)	(21,739)	(71)	(21)	(650)	0
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595	0	%	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2016)	1595	0	%	0	0	0	0	0	0	0
Total of Group 1 Accounts (excluding 1589)		**(3,175,899)**		**(1,449,525)**	**(467,294)**	**(1,239,649)**	**(5,842)**	**(1,092)**	**(12,497)**	**0**
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	0	kWh	0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	0	kWh	0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act	1508	0	kWh	0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Other	1508	0	kWh	0	0	0	0	0	0	0
Retail Cost Variance Account - Retail	1518	(146,989)	kWh	(67,768)	(21,566)	(56,783)	(269)	(50)	(552)	0
Misc. Deferred Debits	1525	0	kWh	0	0	0	0	0	0	0
Retail Cost Variance Account - STR	1548	82,436	kWh	38,006	12,095	31,846	151	28	310	0
Board-Approved CDM Variance Account	1567	0	kWh	0	0	0	0	0	0	0
Extra-Ordinary Event Costs	1572	0	kWh	0	0	0	0	0	0	0
Deferred Rate Impact Amounts	1574	0	kWh	0	0	0	0	0	0	0
RSVA - One-time	1582	0	kWh	0	0	0	0	0	0	0
Other Deferred Credits	2425	0	kWh	0	0	0	0	0	0	0
Total of Group 2 Accounts		**(64,553)**		**(29,762)**	**(9,471)**	**(24,938)**	**(118)**	**(22)**	**(243)**	**0**
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account)	1592	0	kWh	0	0	0	0	0	0	0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	0	kWh	0	0	0	0	0	0	0
Total of Account 1592		**0**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
LRAM Variance Account **(Enter dollar amount for each class)**	1568	**475,677**		67,426	264,755	84,638	(1,450)	(1,091)	61,399	0
(Account 1568 - total amount allocated to classes)		475,677								
Variance		(0)								
Renewable Generation Connection OM&A Deferral Account	1532	**0**	kWh	0	0	0	0	0	0	0
Total of Group 1 Accounts (1550, 1551, 1584, 1586 and 1595)		**(121,918)**		**(41,503)**	**(19,225)**	**(59,863)**	**(252)**	**(55)**	**(1,021)**	**0**
Total of Account 1580 and 1588 (not allocated to WMPs)		**(3,053,981)**		**(1,408,022)**	**(448,069)**	**(1,179,786)**	**(5,591)**	**(1,038)**	**(11,476)**	**0**
Balance of Account 1589 Allocated to Non-WMPs		**118,353**		**8,554**	**4,891**	**103,374**	**0**	**0**	**1,533**	**0**
Group 2 Accounts (including 1592, 1532)		**(64,553)**		**(29,762)**	**(9,471)**	**(24,938)**	**(118)**	**(22)**	**(243)**	**0**
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component	1575	0	kWh	0	0	0	0	0	0	0
Accounting Changes Under CGAAP Balance + Return Component	1576	0	kWh	0	0	0	0	0	0	0
Total Balance Allocated to each class for Accounts 1575 and 1576		**0**		**0**	**0**	**0**	**0**	**0**	**0**	**0**

Account 1589 reference calculation by customer and consumption	
Account 1589 / Number of Customers	$2.82
1589/total kwh	$0.0002

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2018 Deferral/Variance Account W

		Amounts from Sheet 2	Allocator						
LV Variance Account	1550	0	kWh	0	0	0	0	0	0
Smart Metering Entity Charge Variance Account	1551	35,842	# of Customers	0	0	0	0	0	0
RSVA - Wholesale Market Service Charge	1580	(2,438,120)	kWh	0	0	0	0	0	0
RSVA - Retail Transmission Network Charge	1584	(98,688)	kWh	0	0	0	0	0	0
RSVA - Retail Transmission Connection Charge	1586	0	kWh	0	0	0	0	0	0
RSVA - Power (excluding Global Adjustment)	1588	(615,861)	kWh	0	0	0	0	0	0
RSVA - Global Adjustment	1589	118,353	Non-RPP kWh	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	0	%	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	0	%	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2011)	1595	0	%	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	0	%	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	0	%	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	(59,072)	%	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595	0	%	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2016)	1595	0	%	0	0	0	0	0	0
Total of Group 1 Accounts (excluding 1589)		**(3,175,899)**		**0**	**0**	**0**	**0**	**0**	**0**
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	0	kWh	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	0	kWh	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act	1508	0	kWh	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Other	1508	0	kWh	0	0	0	0	0	0
Retail Cost Variance Account - Retail	1518	(146,989)	kWh	0	0	0	0	0	0
Misc. Deferred Debits	1525	0	kWh	0	0	0	0	0	0
Retail Cost Variance Account - STR	1548	82,436	kWh	0	0	0	0	0	0
Board-Approved CDM Variance Account	1567	0	kWh	0	0	0	0	0	0
Extra-Ordinary Event Costs	1572	0	kWh	0	0	0	0	0	0
Deferred Rate Impact Amounts	1574	0	kWh	0	0	0	0	0	0
RSVA - One-time	1582	0	kWh	0	0	0	0	0	0
Other Deferred Credits	2425	0	kWh	0	0	0	0	0	0
Total of Group 2 Accounts		**(64,553)**		**0**	**0**	**0**	**0**	**0**	**0**
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account)	1592	0	kWh	0	0	0	0	0	0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	0	kWh	0	0	0	0	0	0
Total of Account 1592		**0**		**0**	**0**	**0**	**0**	**0**	**0**
LRAM Variance Account **(Enter dollar amount for each class)**	1568	**475,677**		0	0	0	0	0	0
(Account 1568 - total amount allocated to classes)		475,677							
Variance		**(0)**							
Renewable Generation Connection OM&A Deferral Account	1532	**0**	kWh	0	0	0	0	0	0
Total of Group 1 Accounts (1550, 1551, 1584, 1586 and 1595)		**(121,918)**		**0**	**0**	**0**	**0**	**0**	**0**
Total of Account 1580 and 1588 (not allocated to WMPs)		**(3,053,981)**		**0**	**0**	**0**	**0**	**0**	**0**
Balance of Account 1589 Allocated to Non-WMPs		**118,353**		**0**	**0**	**0**	**0**	**0**	**0**
Group 2 Accounts (including 1592, 1532)		**(64,553)**		**0**	**0**	**0**	**0**	**0**	**0**
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component	1575	0	kWh	0	0	0	0	0	0
Accounting Changes Under CGAAP Balance + Return Component	1576	0	kWh	0	0	0	0	0	0
Total Balance Allocated to each class for Accounts 1575 and 1576		**0**		**0**	**0**	**0**	**0**	**0**	**0**

Account 1589 reference calculation by customer and consumption	
Account 1589 / Number of Customers	$2.82
1589/total kwh	$0.0002

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2018 Deferral/Variance Account Wo

		Amounts from Sheet 2	Allocator							
LV Variance Account	1550	0	kWh	0	0	0	0	0	0	0
Smart Metering Entity Charge Variance Account	1551	35,842	# of Customers	0	0	0	0	0	0	0
RSVA - Wholesale Market Service Charge	1580	(2,438,120)	kWh	0	0	0	0	0	0	0
RSVA - Retail Transmission Network Charge	1584	(98,688)	kWh	0	0	0	0	0	0	0
RSVA - Retail Transmission Connection Charge	1586	0	kWh	0	0	0	0	0	0	0
RSVA - Power (excluding Global Adjustment)	1588	(615,861)	kWh	0	0	0	0	0	0	0
RSVA - Global Adjustment	1589	118,353	Non-RPP kWh	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	0	%	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	0	%	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2011)	1595	0	%	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	0	%	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	0	%	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	(59,072)	%	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595	0	%	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2016)	1595	0	%	0	0	0	0	0	0	0
Total of Group 1 Accounts (excluding 1589)		**(3,175,899)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	0	kWh	0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	0	kWh	0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act	1508	0	kWh	0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Other	1508	0	kWh	0	0	0	0	0	0	0
Retail Cost Variance Account - Retail	1518	(146,989)	kWh	0	0	0	0	0	0	0
Misc. Deferred Debits	1525	0	kWh	0	0	0	0	0	0	0
Retail Cost Variance Account - STR	1548	82,436	kWh	0	0	0	0	0	0	0
Board-Approved CDM Variance Account	1567	0	kWh	0	0	0	0	0	0	0
Extra-Ordinary Event Costs	1572	0	kWh	0	0	0	0	0	0	0
Deferred Rate Impact Amounts	1574	0	kWh	0	0	0	0	0	0	0
RSVA - One-time	1582	0	kWh	0	0	0	0	0	0	0
Other Deferred Credits	2425	0	kWh	0	0	0	0	0	0	0
Total of Group 2 Accounts		**(64,553)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account)	1592	0	kWh	0	0	0	0	0	0	0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	0	kWh	0	0	0	0	0	0	0
Total of Account 1592		**0**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
LRAM Variance Account **(Enter dollar amount for each class)**	1568	**475,677**		0	0	0	0	0	0	0
(Account 1568 - total amount allocated to classes)		475,677								
Variance		(0)								
Renewable Generation Connection OM&A Deferral Account	1532	**0**	kWh	0	0	0	0	0	0	0
Total of Group 1 Accounts (1550, 1551, 1584, 1586 and 1595)		**(121,918)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total of Account 1580 and 1588 (not allocated to WMPs)		**(3,053,981)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
Balance of Account 1589 Allocated to Non-WMPs		**118,353**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
Group 2 Accounts (including 1592, 1532)		**(64,553)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component	1575	0	kWh	0	0	0	0	0	0	0
Accounting Changes Under CGAAP Balance + Return Component	1576	0	kWh	0	0	0	0	0	0	0
Total Balance Allocated to each class for Accounts 1575 and 1576		**0**		**0**	**0**	**0**	**0**	**0**	**0**	**0**

Account 1589 reference calculation by customer and consumption	
Account 1589 / Number of Customers	$2.82
1589/total kwh	$0.0002

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2018 Deferral/Variance Account Workform

Please indicate the Rate Rider Recovery Period (in years) | 1

Rate Rider Calculation for Group 1 Deferral / Variance Accounts Balances (excluding Global Adj.)

1550, 1551, 1584, 1586, 1595

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Group 1 Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts	
RESIDENTIAL	kWh	296,393,596	-$ 1,449,525	- **0.0049**	$/kWh
GENERAL SERVICE LESS THAN 50 KW	kWh	94,320,130	-$ 467,294	- **0.0050**	$/kWh
GENERAL SERVICE 50 TO 4,999 KW	**kW**	624,500	-$ 1,239,649	- **1.9850**	**$/kW**
UNMETERED SCATTERED LOAD	kWh	1,176,822	-$ 5,842	- **0.0050**	$/kWh
SENTINEL LIGHTING	**kW**	616	-$ 1,092	- **1.7732**	**$/kW**
STREET LIGHTING	**kW**	7,076	-$ 12,497	- **1.7661**	**$/kW**
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
Total			**-$ 3,175,899**		

Rate Rider Calculation for Group 1 Deferral / Variance Accounts Balances (excluding Global Adj.) - NON-WMP

1580 and 1588

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Group 1 Balance - Non-WMP	Rate Rider for Deferral/Variance Accounts	
RESIDENTIAL	kWh	296,393,596	$ -	**-**	$/kWh
GENERAL SERVICE LESS THAN 50 KW	kWh	94,320,130	$ -	**-**	$/kWh
GENERAL SERVICE 50 TO 4,999 KW	**kW**	624,500	$ -	**-**	**$/kW**
UNMETERED SCATTERED LOAD	kWh	1,176,822	$ -	**-**	$/kWh
SENTINEL LIGHTING	**kW**	616	$ -	**-**	**$/kW**
STREET LIGHTING	**kW**	7,076	$ -	**-**	**$/kW**
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
Total			**$ -**		

Only for rate classes with WMP customers are the Deferral/Variance Account Rate Riders for Non-WMP calculated separately in the table above. For all rate classes without WMP customers, balances in Accounts 1580 and 1588 are included in Deferral/Variance Account Rate Riders calculated in the first table above and disposed through a combined Deferral/Variance Account and Rate Rider.

Rate Rider Calculation for RSVA - Power - Global Adjustment

Balance of Account 1589 Allocated to Non-WMPs

Rate Class (Enter Rate Classes in cells below)	Units	kWh	Allocated Global Adjustment Balance	Rate Rider for RSVA - Power - Global Adjustment	
RESIDENTIAL	kWh	13,130,236	$ 8,554	**0.0007**	$/kWh
GENERAL SERVICE LESS THAN 50 KW	kWh	7,507,882	$ 4,891	**0.0007**	$/kWh
GENERAL SERVICE 50 TO 4,999 KW	kWh	158,670,274	$ 103,374	**0.0007**	$/kWh
UNMETERED SCATTERED LOAD	kWh	-	$ -	**-**	$/kWh
SENTINEL LIGHTING	kWh	-	$ -	**-**	$/kWh
STREET LIGHTING	kWh	2,353,224	$ 1,533	**0.0007**	$/kWh
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	

		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
Total			**$ 118,353**	

Rate Rider Calculation for Group 2 Accounts

Rate Class **(Enter Rate Classes in cells below)**	**Units**	**# of Customers**	**Allocated Group 2 Balance**	**Rate Rider for Group 2 Accounts**	
RESIDENTIAL	# of Customers	29,789	-$ 29,762	**-$ 0.08**	per customer per month
GENERAL SERVICE LESS THAN 50 KW	kWh	94,320,130	-$ 9,471	**-$ 0.0001**	$/kWh
GENERAL SERVICE 50 TO 4,999 KW	**kW**	624,500	-$ 24,938	**-$ 0.0399**	**$/kW**
UNMETERED SCATTERED LOAD	kWh	1,176,822	-$ 118	**-$ 0.0001**	$/kWh
SENTINEL LIGHTING	**kW**	616	-$ 22	**-$ 0.0356**	**$/kW**
STREET LIGHTING	**kW**	7,076	-$ 243	**-$ 0.0343**	**$/kW**
		-	$ -	**$ -**	
		-	$ -	**$ -**	
		-	$ -	**$ -**	
		-	$ -	**$ -**	
		-	$ -	**$ -**	
		-	$ -	**$ -**	
		-	$ -	**$ -**	
		-	$ -	**$ -**	
		-	$ -	**$ -**	
		-	$ -	**$ -**	
		-	$ -	**$ -**	
		-	$ -	**$ -**	
		-	$ -	**$ -**	
		-	$ -	**$ -**	
Total			**-$ 64,553**		

Rate Rider Calculation for Accounts 1575 and 1576

Please indicate the Rate Rider Recovery Period (in years)	**1**

Rate Class **(Enter Rate Classes in cells below)**	**Units**	**# of Customers**	**Allocated Accounts 1575 and 1576 Balances**	**Rate Rider for Accounts 1575 and 1576**	
RESIDENTIAL	# of Customers	29,789	$ -	**-**	per customer per month
GENERAL SERVICE LESS THAN 50 KW	kWh	94,320,130	$ -	**-**	$/kWh
GENERAL SERVICE 50 TO 4,999 KW	**kW**	624,500	$ -	**-**	**$/kW**
UNMETERED SCATTERED LOAD	kWh	1,176,822	$ -	**-**	$/kWh
SENTINEL LIGHTING	**kW**	616	$ -	**-**	**$/kW**
STREET LIGHTING	**kW**	7,076	$ -	**-**	**$/kW**
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
Total			**$ -**		

Rate Rider Calculation for Accounts 1568

Please indicate the Rate Rider Recovery Period (in years)	**1**

Rate Class **(Enter Rate Classes in cells below)**	**Units**	**kW / kWh / # of Customers**	**Allocated Account 1568 Balance**	**Rate Rider for Account 1568**	
RESIDENTIAL	kWh	296,393,596	$ 67,426	**0.0002**	$/kWh
GENERAL SERVICE LESS THAN 50 KW	kWh	94,320,130	$ 264,755	**0.0028**	$/kWh
GENERAL SERVICE 50 TO 4,999 KW	**kW**	624,500	$ 84,638	**0.1355**	**$/kW**
UNMETERED SCATTERED LOAD	kWh	1,176,822	-$ 1,450	**- 0.0012**	$/kWh
SENTINEL LIGHTING	**kW**	616	-$ 1,091	**- 1.7711**	**$/kW**
STREET LIGHTING	**kW**	7,076	$ 61,399	**8.6771**	**$/kW**
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
		-	$ -	**-**	
Total			**$ 475,677**		

APPENDIX 2

Analysis Workform

Ontario Energy Board

GA Analysis Workform

Purpose:
To calculate an approximate expected balance in Account 1589 RSVA - GA and compare the expected amount to the amount in the general ledger. Material differences between the two need to be

Notes to GA Analysis:
Refer to the GA Analysis Tab to complete the below steps.
Note that this is a generic analysis template, utilities may need to alter the analysis as needed for their specific circumstances. Any alternations to the analysis must be clearly disclosed and

1 Indicate which years the balance requested for disposition pertains to (e.g. 2016, or 2016 and 2015)

2 Complete the Consumption Data Table for consumption (unadjusted for the loss factor) for each year that is being requested for disposition. The data should agree to the RRR data reported,

3 GA Billing Rate

- Indicate the GA rate that is used to bill customers (also used for unbilled revenue) in the drop down box. Note that the “Other” rate is to represent a combination of the first estimate, second estimate and/or actual rate.
- In the GA Billing Rate Description textbox, provide a description of the GA billing rate that is used, i.e. first estimate, second estimate, or actual. Explain how the GA billing rate is determined for billing cycles that span more than one load month. Confirm that the GA rate that is used is applied consistently for all billing and unbilled revenue transactions for non-RPP Class B customers in each customer class.* In addition, where the same GA rate is not used for non-RPP Class B customers in all customer classes, explain what GA rate is applied to each customer class.
- Where a distributor does not apply the same GA rate to all non-RPP Class B customers, the distributor must adapt the GA Analysis for this and breakdown the monthly non-RPP Class B volumes for each GA rate that was applied.

*O.Reg 429/04, section 16(3)

Note: Distributors should create a copy of the Analysis of Expected GA Amount table in a separate tab for each year that is being requested for disposition, calculate the net change in expected GA balance in the year, determine the reconciliation adjustments (see note 6) and assess materiality for each year requested for disposition.

4 Analysis of Expected GA Amount

- The analysis calculates a balance in Account 1589 RSVA- GA that can be reasonably expected. Distributors are charged by the IESO on a calendar/load month basis at the actual GA rate for relevant volumes each month. The methodology used in the GA Analysis is based on the calendar/load month consumption from revenue amounts (derived from billed and unbilled consumption). This is done by taking the billed kWh volumes (which would not be expected to align with the calendar/load month) and deducting the unbilled kWh consumption from the prior month and adding the unbilled kWh consumption of the current month. This approach to calculating monthly kWh volumes is used to represent calendar/load month consumption.
- Once calendar/load month kWh volumes are determined, the monthly GA rate(s) used to bill non-RPP Class B customers for each month as posted by the IESO can be multiplied by the consumption to determine expected GA revenue amounts. Therefore, a blended GA rate will not be required as the kWh volumes for revenues have been approximated on a calendar/load month basis as well. The expected GA revenues can then be compared to the actual GA rate charged by the IESO for each month multiplied by the consumption to determine a balance that can be expected in Account 1589 RSVA-GA.
- This methodology expects volume differences would not be significant. However, if unbilled consumption is not estimated with adequate precision by a distributor, this could impact the expected balance in Account 1589 RSVA-GA, which may have to be considered in the analysis by the distributor.
- Note that distributors who have more precise monthly kWh volume data available based on allocation of billing data by calendar/load month may propose to use this data in the GA Analysis to calculate the expected GA balance. However, any such methodology that differs from the one described above must be disclosed and explained.

Column F :	The consumption column is for monthly non-RPP Class B (loss adjusted) consumption billed. Total annual consumption is expected to differ from the Consumption Data Table (note 2) by the loss factor. Utilities are expected to ensure that the difference in consumption between that in column F and the Consumption Data Table are reasonable.
Column G, H :	Prior month unbilled consumption is to be deducted and current month unbilled consumption is to be added. Note that monthly non-RPP Class B unbilled consumption may not be readily available and may require estimates or allocations to be done.
Column J :	Fill in the GA rate billed by linking the cells to the applicable cells in the GA Rates Per IESO Website Table.
Column L:	Fill in the actual GA rate paid by linking the cells to the applicable cells in the GA Rates Per IESO Website Table.

5 Reconciling Items

Enter the net change in principal balance in the GL. This will equal to the transactions recorded in the account for the year. If multiple years are requested for disposition, the sum of the net changes in principal balance will equal the cumulative principal balance requested for disposition.

The purpose of this section is to ensure that reconciling items have been appropriately factored into the GA Analysis. Reconciling items must be considered for each year requested for disposition.

For each reconciling item, indicate whether the item is a reconciling item to the utility's specific circumstances using the column "Applicability of Reconciling Item". Explain how each item applies or does not apply as a reconciling item. Assess if each reconciling item is significant, if so they must be quantified.

Reconciling items may include:

1) Impacts to GA from RPP settlement true up amounts
Note that effective May 23, 2017, per the OEB's letter titled *Guidance on Disposition of Accounts 1588 and 1589*, applicants must reflect RPP Settlement true-up claims pertaining to the period that is being requested for disposition in Account 1588 and Account 1589. This would include true ups to the pro-ration of the GA charge based on RPP vs. non-RPP volumes, true up of GA accrual expense to the actual expense per invoice.
   a. Prior year impacts should be removed,
   b. Current year impacts should be added.

2) Unbilled revenue differences between the unbilled and actual billed amounts, which could relate to rate used or consumption volumes

Analyses may have to be performed to identify the portion of the billed amounts that corresponded to the amount that was unbilled and recorded in the general ledger.
   a. Prior year end unbilled revenue differences should be removed,
   b. Current year end unbilled revenue differences should be added.

3) Accrual to actual differences in long term load transfers
Amounts pertaining to load transfers may be unknown at the end of the year and therefore, are accrued based on an estimate. A true-up to actuals would then be done in the following year. Note that per the December 21, 2015 Distribution System Code Amendment, all load transfer arrangements shall be eliminated by transferring the load transfer customers to the physical distributor by June 21, 2017.
   a. Prior year end differences should be removed
   b. Current year end differences should be added.

4) GA balances pertaining to Class A customers must be excluded from the GA balance as the GA balance should only relate to Class B.
Transactions pertaining to Class A customers are recorded in Account 1589 RSVA-GA and should net to zero. However, there may be balances pertaining to Class A included in the account at the end of the year due to timing issues. For example, a balance pertaining to Class A customers may exist if revenues are not accrued on the same basis as expenses.
If any such balances pertaining to Class A exist, the distributor must also ensure that these amounts are excluded from the Account 1589 RSVA-GA balance requested for disposition.

5) Significant prior period billing adjustments
Cancel and rebills for billing adjustments may be recorded in the current year revenue GL balance but would not be included in the current year consumption charged by the IESO.

6) Differences in GA IESO posted rate and rate charged on IESO invoice
If there are any differences between the GA IESO posted rate used in the Analysis of Expected GA Amount table above (note 4) and the GA rate that is actually charged per a distributor's invoice for non-RPP volumes Class B, the impact of this may need to be quantified. The monthly difference in rate should be multiplied by non-RPP Class B volumes.

7-10) Any other items that cause differences between the expected GA amount and the GA recorded in the general ledger.
Any remaining unreconciled balance that is greater than +/- 1% of the GA payments to the IESO annually must be analyzed and investigated to identify any additional reconciling items or to identify corrections to the balance requested for disposition.

6 Materiaility Threshold

The net change in principal balance in the GL should be summed with the reconciling items to determine the adjusted net change in principal balance in the GL. This amount will be compared to the expected net change in the principal balance as calculated in the Analysis of Expected GA Amount table (note 4). The difference between the two will be compared to the annual GA payments to the IESO. If the difference is greater than +/-1%, then distributors may reassess the reconciling items to determine if there are additional reconciling items that could impact the difference.

Ontario Energy Board

GA Analysis Workform

Update from July 20th DVA workform version:
-Cells C87,D87,E87, H87 - name of cells updated for cell reference
-Cells F88 to F91 and G88 to G91 - formula of cells updated

Account 1589 Global Adjustment (GA) Analysis Workform

Input cells
Drop down cells

Note 1 **Year(s) Requested for Disposition** **2015**

Note 2 **Consumption Data Excluding for Loss Factor (Data to agree with RRR as applicable)**

Year		**2015**		
Total Metered excluding WMP	C = A+B	669,387,527	kWh	100%
RPP	A	422,114,959	kWh	63.1%
Non RPP	B = D+E	247,272,568	kWh	36.9%
Non-RPP Class A	D	-	kWh	0.0%
Non-RPP Class B*	E	247,272,568	kWh	36.9%

*Non-RPP Class B consumption reported in this table is not expected to directly agree with the Non-RPP Class B Including Loss Adjusted Billed Consumption in the GA Analysis of Expected Balance table below. The difference should be equal to the loss factor.

Note 3 **GA Billing Rate**

GA is billed on the 1st Estimate

GA Billing Rate Description

GA Billing Rate is billed based off the 1st estimate. To determine the GA billing rate for billing cycles that span more than one load month, PUC has implemented specific billing codes for each month of the year which is assigned the GA rate for the respective month. The consumption in the billing cycle is prorated between the two months based on the number of days in each month. This consumption is then multiplied by the GA rate attached to each month's billing code. This method is used consistently across all customer classes.

Note 4 **Analysis of Expected GA Amount**

Year **2015**

Calendar Month	**Non-RPP Class B Including Loss Factor Billed Consumption (kWh)**	**Deduct Previous Month Unbilled Loss Adjusted Consumption (kWh)**	**Add Current Month Unbilled Loss Adjusted Consumption (kWh)**	**Non-RPP Class B Including Loss Adjusted Consumption, Adjusted for Unbilled (kWh)**	**GA Rate Billed ($/kWh)**	**$ Consumption at GA Rate Billed**	**GA Actual Rate Paid ($/kWh)**	**$ Consumption at Actual Rate Paid**	**Expected GA Variance ($)**
	F	**G**	**H**	**I = F-G+H**	**J**	**K = I*J**	**L**	**M = I*L**	**=M-K**
January	22,791,492			22,791,492	0.05549	$ 1,264,700	0.05068	$ 1,155,073	-$ 109,627
February	22,099,897			22,099,897	0.06981	$ 1,542,794	0.03961	$ 875,377	-$ 667,417
March	24,590,727			24,590,727	0.03604	$ 886,250	0.06290	$ 1,546,757	$ 660,507
April	20,482,691			20,482,691	0.06705	$ 1,373,364	0.09559	$ 1,957,940	$ 584,576
May	20,786,848			20,786,848	0.09416	$ 1,957,290	0.09668	$ 2,009,672	$ 52,383
June	19,501,865			19,501,865	0.09228	$ 1,799,632	0.09540	$ 1,860,478	$ 60,846
July	21,437,271			21,437,271	0.08888	$ 1,905,345	0.07883	$ 1,689,900	-$ 215,445
August	21,617,221			21,617,221	0.08805	$ 1,903,396	0.08010	$ 1,731,539	-$ 171,857
September	21,340,889			21,340,889	0.08270	$ 1,764,892	0.06703	$ 1,430,480	-$ 334,412
October	20,869,341			20,869,341	0.06371	$ 1,329,586	0.07544	$ 1,574,383	$ 244,797
November	20,956,545			20,956,545	0.07623	$ 1,597,517	0.11320	$ 2,372,281	$ 774,763
December	22,052,806			22,052,806	0.11462	$ 2,527,693	0.09471	$ 2,088,621	-$ 439,071
Net Change in Expected GA Balance in the Year (i.e. Transactions in the Year)	**258,527,591**	**-**	**-**	**258,527,591**		**$ 19,852,458**		**$ 20,292,502**	**$ 440,044**

20,115,120.00
262,662.24

Note 5 **Reconciling Items**

	Item	**Applicability of Reconciling Item (Y/N)**	**Amount (Quantify if it is a significant reconciling item)**	**Explanation**
Net Change in Principal Balance in the GL (i.e. Transactions in the Year)			**$ 177,382**	
1a	Remove impacts to GA from prior year RPP Settlement true up process that are booked in current year	N		

1b	Add impacts to GA from current year RPP Settlement true up process that are booked in subsequent year	N		
2a	Remove prior year end unbilled to actual revenue differences	Y	$ 202,395	2014 unbilled revenue variance as compared to actual (billed in 2015)
2b	Add current year end unbilled to actual revenue differences	Y	$ 65,330	2015 unbilled estimate revenue variance as compated to actual (billed in 2016)
3a	Remove difference between prior year accrual to forecast from long term load transfers	N		
3b	Add difference between current year accrual to forecast from long term load transfers	N		
4	Remove GA balances pertaining to Class A customers	N		
5	Significant prior period billing adjustments included in current year GL balance but would not be included in the billing consumption used in the GA Analysis	N		
6	Differences in GA IESO posted rate and rate charged on IESO invoice	N		
7				
8				
9				
10				

Note 6	**Adjusted Net Change in Principal Balance in the GL**	$ 445,108
	Net Change in Expected GA Balance in the Year Per Analysis	$ 440,044
	Unresolved Difference	$ 5,064
	Unresolved Difference as % of Expected GA Payments to IESO	0.0%

Note 1 **Year(s) Requested for Disposition** **2016**

Note 2 **Consumption Data Excluding for Loss Factor (Data to agree with RRR as applicable)**

Year		**2015**		
Total Metered excluding WMP	C = A+B	637,462,404	kWh	100%
RPP	A	394,497,102	kWh	58.9%
Non RPP	B = D+E	242,965,301	kWh	36.3%
Non-RPP Class A	D		kWh	0.0%
Non-RPP Class B*	E	242,965,301	kWh	36.3%

*Non-RPP Class B consumption reported in this table is not expected to directly agree with the Non-RPP Class B Including Loss Adjusted Billed Consumption in the GA Analysis of Expected Balance table below. The difference should be equal to the loss factor.

Note 3 **GA Billing Rate**

GA is billed on the 1st Estimate

GA Billing Rate Description

GA Billing Rate is billed based off the 1st estimate. To determine the GA billing rate for billing cycles that span more than one load month, PUC has implemented specific billing codes for each month of the year which is assigned the GA rate for the respective month. The consumption in the billing cycle is prorated between the two months based on the number of days in each month. This consumption is then multiplied by the GA rate attached to each month's billing code. This method is used consistently across all customer classes.

Note 4 **Analysis of Expected GA Amount**

Year **2015**

Calendar Month	**Non-RPP Class B Including Loss Factor Billed Consumption (kWh)**	**Deduct Previous Month Unbilled Loss Adjusted Consumption (kWh)**	**Add Current Month Unbilled Loss Adjusted Consumption (kWh)**	**Non-RPP Class B Including Loss Adjusted Consumption, Adjusted for Unbilled (kWh)**	**GA Rate Billed ($/kWh)**	**$ Consumption at GA Rate Billed**	**GA Actual Rate Paid ($/kWh)**	**$ Consumption at Actual Rate Paid**	**Expected GA Variance ($)**
	F	**G**	**H**	**I = F-G+H**	**J**	**K = I*J**	**L**	**M = I*L**	**=M-K**
January	23,126,332			23,126,332	0.08423	$ 1,947,931	0.09179	$ 2,122,766	$ 174,835
February	21,808,625			21,808,625	0.10384	$ 2,264,608	0.09851	$ 2,148,368	-$ 116,240
March	23,458,608			23,458,608	0.09022	$ 2,116,436	0.10610	$ 2,488,958	$ 372,523
April	18,885,805			18,885,805	0.12115	$ 2,288,015	0.11132	$ 2,102,368	-$ 185,647
May	20,820,225			20,820,225	0.10405	$ 2,166,344	0.10749	$ 2,237,966	$ 71,622
June	21,117,537			21,117,537	0.11650	$ 2,460,193	0.09545	$ 2,015,669	-$ 444,524
July	20,559,715			20,559,715	0.07667	$ 1,576,313	0.08306	$ 1,707,690	$ 131,377
August	22,633,496			22,633,496	0.08569	$ 1,939,464	0.07103	$ 1,607,657	-$ 331,807
September	20,917,154			20,917,154	0.07060	$ 1,476,751	0.09531	$ 1,993,614	$ 516,863
October	19,296,231			19,296,231	0.09720	$ 1,875,594	0.11226	$ 2,166,195	$ 290,601
November	20,671,466			20,671,466	0.12271	$ 2,536,596	0.11109	$ 2,296,393	-$ 240,202
December	22,627,347			22,627,347	0.10594	$ 2,397,141	0.08708	$ 1,970,389	-$ 426,752
Net Change in Expected GA Balance in the Year (i.e. Transactions in the Year)	**255,922,541**	**-**	**-**	**255,922,541**		**$ 25,045,386**		**$ 24,858,033**	**-$ 187,353**

Note 5 **Reconciling Items**

	Item	Applicability of Reconciling Item (Y/N)	Amount (Quantify if it is a significant reconciling item)	Explanation
Net Change in Principal Balance in the GL (i.e. Transactions in the Year)			**-$ 103,639**	
1a	Remove impacts to GA from prior year RPP Settlement true up process that are booked in current year	N		
1b	Add impacts to GA from current year RPP Settlement true up process that are booked in subsequent year	N		
2a	Remove prior year end unbilled to actual revenue differences	Y	-$ 65,330	2015 unbilled revenue variance as compared to actual (billed in 2016)
2b	Add current year end unbilled to actual revenue differences	Y	$ -	2016 unbilled revenue calculation used actual billing data (i.e. there is no variance)
3a	Remove difference between prior year accrual to forecast from long term load transfers	N		
3b	Add difference between current year accrual to forecast from long term load transfers	N		
4	Remove GA balances pertaining to Class A customers	N		
5	Significant prior period billing adjustments included in current year GL balance but would not be included in the billing consumption used in the GA Analysis	N		
6	Differences in GA IESO posted rate and rate charged on IESO invoice	N		
7				
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10				

Note 6	**Adjusted Net Change in Principal Balance in the GL**	-$ 168,969
	Net Change in Expected GA Balance in the Year Per Analysis	-$ 187,353
	Unresolved Difference	$ 18,384
	Unresolved Difference as % of Expected GA Payments to IESO	0.1%

Note 7 **Summary of GA (if multiple years requested for disposition)**

Year	Annual Net Change in Expected GA Balance from GA Analysis (cell K59)	Net Change in Principal Balance in the GL (cell D65)	Reconciling Items (sum of cells D66 to D78)	Adjusted Net Change in Principal Balance in the GL	Unresolved Difference	Payments to IESO (cell J59)	Unresolved Difference as % of Expected GA Payments to IESO
2015	$ 440,044	$ 177,382	$ 267,726	$ 445,108	$ 5,064	$ 20,292,502	0.0%
2016	-$ 187,353	-$ 103,639	-$ 65,330	-$ 168,969	$ 18,384	$ 24,858,033	0.1%
				$ -	$ -		0.0%
				$ -	$ -		0.0%
Cumulative Balance	**$ 252,691**	**$ 73,743**	**$ 202,395**	**$ 276,138**	**$ 23,447**	**$ 45,150,534.84**	**N/A**

APPENDIX 3

Certificate

Certificate

I, Terry Greco, Vice President of Finance and Corporate Support of PUC Distribution Inc., certify that PUC Distribution has robust processes and internal controls in place for the preparation, review, verification and oversight of account balances being proposed for disposition in this Application.

T Greco

Terry Greco

Vice President of Finance and Corporate Support