EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

2019 Cost of Service

Chapleau PUC.
EB-2018-0087

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1.2 EXECUTIVE SUMMARY

1.2.1 INTRODUCTION

Chapleau PUC. ("CPUC") is pleased to present its Cost of Service application for rates effective May 1, 2019. This application consists of the following Exhibits, and Excel live models in support of the evidence presented in this application.

- ✓ Exhibit 1: Administrative Documents
- ✓ Exhibit 2: Rate Base and DSP
- ✓ Exhibit 3: Revenues
- ✓ Exhibit 4: Operation, Maintenance and Administrative Costs
- ✓ Exhibit 5: Cost of Capital
- ✓ Exhibit 6: Revenue Requirement
- ✓ Exhibit 7: Cost Allocation
- ✓ Exhibit 8: Rate Design
- ✓ Exhibit 9: Deferral and Variance Accounts

- ✓ EB-2018-0087 CPUC 2019 Benchmarking Forecast Model
- ✓ EB-2018-0087 CPUC 2019 Cost Allocation
- ✓ EB-2018-0087 CPUC 2019 LRAMVA Workform
- ✓ EB-2018-0087 CPUC 2019 PILs Workform
- ✓ EB-2018-0087 CPUC 2019 Rev Req Workform
- ✓ EB-2018-0087 CPUC 2019 RTSR Workform
- ✓ EB-2018-0087 CPUC 2019 Load Forecast Model
- ✓ EB-2018-0087 CPUC 2019 COS Checklist
- ✓ EB-2018-0087 CPUC 2019 DVA Continuity Schedule

- ✓ EB-2018-0087 CPUC 2019 Chapter 2 Appendices [1]

All documents have been submitted to the OEB via their website.

The application along with all supporting evidence will also be posted on the utility’s website and customers informed of the filing via Twitter and Facebook once the application is accepted by the Ontario Energy Board (OEB).

SUMMARY OF APPLICATION INTENDED FOR CPUC CUSTOMERS[2]

CPUC is pleased to present at the next page a brief summary of the application. The summary will be posted as a stand-alone document on the OEB's website for review by the general public and be made available to customers of CPUC via its website and social media.

[1] MFR - Chapter 2 appendices in live Microsoft Excel format
[2] MFR – Summary of Application

Chapleau PUC
2019 Rate Application

Dear Chapleau PUC customers,

Chapleau PUC has applied to the Ontario Energy Board to increase its electricity distribution rates effective May 1, 2019. If the application is approved, a typical residential customer of Chapleau PUC will see an increase of approximately $4.70 per month and a typical General Service < 50kW customer of Chapleau PUC will see an increase of approximately $25.95 per month. (ref: Exhibit 8 for detailed bill impacts)

The application, which was filed with the Ontario Energy Board on August 31, 2018, is called a "Cost of Service" and involves the setting and approval of new rate based on the value of the utility's assets and the cost incurred in providing service to its customers. For Chapleau PUC, this involves the maintenance and service of one transformer stations with two transformers, poles, lines, transformers, and meters. (ref: Exhibit 2) All wages and material related to the distribution of power form the basis for the costs included in the application (ref: Exhibit 4).

CPUC is requesting a Revenue Requirement fo $1,004,820. This represents an increase of $208,901 from its last Cost of Service in 2012.(ref: Exhibit 6). The table below shows the major changes since the utility's last Cost of Service in 2012. Over the past 7 years, Chapleau PUC has added approximately 450K in assets (ref: Exhibit 2) on which it's allowed to recover a return of 11K (Exhibit 5). The increase in assets has resulted in an increase in yearly depreciation expense of 45K which Chapleau PUC can also recover through rates. Chapleau PUC's yearly operating costs have increased by 177K since 2012. Taxes have been eliminated, and revenues from charges other than rates, which offset the revenue requirement have increased by 9K. the table below shows the movement in revenue requirement since 2012.

Movement in Revenue Requirement since 2012

2012 Revenue Requirement	$795,919	2012 Approved Revenue Requirement
Increase in Net Fixed Asset	$449,927	Added Assets (poles/meters/vehicle) since 2012
Reduction in Working Cash Allowance	-$211,443	Reduction of 7.5% as per OEB policy
Increase in Rate (Asset) Base	$238,484	Increase in value of assets + cashflow requirement
Increase Allowable Return on Assets	$11,644	Increase in Return on assets as a result of new assets installed since 2012.
Increase in Operating Costs + Property Taxes	$176,823	Increase due to 1) change in structure (no longer virtual) 2) Increase in regulatory costs 3) Wage increase for succession planning
Increase in Depreciation Expense	$45,130	Increase in depreciation as a result of added assets
Reduction in Taxes (PILs)	-$13,814	Reduction due to Change in accounting standards
Increase in Other Revenues	-$8,994	Increase (shown as negative) of revenue offset
Increase in Revenue Requirement	$208,901	Increase in total revenue requirement
2019 Revenue Requirement	$1,004,820	2019 Proposed Revenue Requirement

Aligning Rates with Costs

There are several reasons why Chapleau PUC is seeking a rate increase starting in May of 2019. The main reason is that Chapleau PUC's current base rates were approved set in 2012 and subsequently updated for the rate of inflation in 2015. As such, revenues from rates can no longer support Chapleau PUCs current costs.

Operating costs have increased by approximately $176,823 over the past five years. The major contributing factors include:

- ✓ An increase in outside services for regulatory requirements. (ref: Exhibit 4)
- ✓ Wage increases for succession planning. (ref: Exhibit 4)
- ✓ Increased depreciation expense related to the purchase of a new utility truck. (ref: Exhibit 4)
- ✓ Costs associated with the merger of the two companies including the transfer of 100k in net fixed assets. (ref: Exhibit 4)
- ✓ Reduction in revenue offsets related to Hydro One's reducing Chapleau PUCs service to 911 emergencies only. (ref: Exhibit 3)

As of January 1, 2018, the utility no longer operates as a "virtual" utility where employees were employed by Chapleau Energy Services and contracted out to Chapleau PUC. The merger was intended to reduce regulatory complexity and administrative burden and to make rate applications a less difficult process. The result is a company that can better control the costs associated with rates, and increased transparency.

A full slide presentation is available on our website at;

http://www.chapleau.ca/en/townshipservices/publicutilities.asp

Aging Infrastructure

Like most utilities in Ontario, Chapleau PUC faces the need to renew aging electrical infrastructure. Much of the province's electrical system was built 30 to 50 years ago and has reached the end of its productive life.

- ✓ Chapleau PUC is working on balancing its need for assets and the money needed to pay for assets keeping in mind its customers' need for value.

Chapleau PUC has invested over $450K in assets since 2012 – and over 20% of that investment is in 'field' assets - the wires, transformers and meters that are needed to reliably and safely deliver power to its customers. 80% was related to a boom truck which needed replacing. (ref: Exhibit 2)

Chapleau PUC has incurred other costs (wages and materials) in order to be able to make use of new systems. Much like other utilities, Chapleau PUC also faces external cost pressures, such as inflation. (ref: Exhibit 4)

Chapleau PUC has continued its efforts to improve operational performance and service excellence. Some highlights include:

- ✓ Reliability has improved steadily year after year, for the past ten years. (ref: Exhibit 2)
- ✓ Chapleau PUC has consistently exceeded OEB standards for customer service – responding to 90% of its customer calls within 30 seconds. (ref: Exhibit 2)
- ✓ In 2017 26,4M million kWh were delivered to Chapleau PUC customers. Even though customer counts have decreased, energy deliveries are largely unchanged due to Chapleau PUC customer uptake of conservation and demand management initiatives. (ref: Exhibit 3)

Focus on Customers

By focusing on customer engagement and communications, Chapleau PUC is helping customers make better choices and create healthy, sustainable results for the community it serves.

Chapleau PUC has taken a new attitude towards informing, educating and responding to customer needs as a top priority. Chapleau PUC has recently launched a Facebook and Twitter account to help with customer communications for outages and during conservation campaigns. (ref: Exhibit 1)

This includes Chapleau PUC's ongoing efforts to instill a conservation culture and promote the adoption of conservation to its customers. From residential and business customers to local school children, Chapleau PUC's outreach programs are making a difference and have become integral to Chapleau PUC's communications strategy.

With a new logo, Chapleau PUC is moving forward with a renewed sense of pride as it relates to 'who we are and what we aspire to be' as a company.

Results from a Customer Satisfaction Survey, undertaken by Chapleau PUC in the fall of 2017, demonstrate that the company is moving in a positive direction. It has helped to identify customer attitudes about the utility's conservation programs, smart meters and TOU rates, electricity prices and Chapleau PUC's standing and reputation in the community. The results will assist Chapleau PUC in fine tuning its programs, services and communications use direct and reliable customer feedback.

Overall Chapleau PUC customer satisfaction came in at a 95% approval rating. (ref: Exhibit 1)

Rebuild and Respond

Chapleau PUC is focusing its efforts going forward on enhancing performance levels in all aspects of its operation and planning activities to comply with its regulatory obligations and responsibilities to the Ontario Energy Board (OEB) and the Electrical Safety Authority (ESA).

At the core of Chapleau PUC's mandate, is the responsibility to deliver a trusted source of safe, efficient, and reliable power to its customers. A critical element in that equation is the ongoing pole replacement programs that will ensure the long-term integrity and sustainability of the distribution system.

A newly developed Distribution System Plan (DSP) forms the basis for the utility's capital and maintenance programs. The DSP reflects the latest performance priorities of the distribution system and serves as a placeholder for the longer term projects recommended from the condition (age risk ratings) assessments.

Under a 5-year capital investment plan, the company has embarked on a prudent course to maintain the utility's equipment assets. (ref: Exhibit 2)

Pass-through charges

Chapleau PUC is responsible for billing the customer for pass-through charges which are generally set by the province of the OEB. The billing and collecting of these charges most often create variance accounts which need to be disposed of. The total amount to be refunded to the residential class is a credit of $4,710 and the total amount to be collected from the small business class is $73,084. The proposed dispositon period is of 48 months.(ref: Exhibit 9)

Conclusion

With this filing, Chapleau PUC now looks to the future with the intent to provide essential electricity services to benefit our community and our customers.

1.2.2 BUSINESS PLAN[3]

In compliance with the Rates Handbook issued on October 13, 2016, the utility is pleased to present its 2019 Business Plan in the next Section.

[3] MFR - Plain language description of objectives and business plan and how they relate to the application and the RRFE objectives. Description should aid the OEB in understanding the impacts of the business plan on key areas such as customer service, system reliability, costs and bill impacts. Description of how customer feedback is reflected

2018-2019 BUSINESS PLAN

Chapleau Public Utilities Corporation

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1. Executive Summary

Chapleau Public Utilities Corporation. (“CPUC” or the “Utility”) is a fully licensed distributor of electricity under distribution license ED-2002-0528 issued by the Ontario Energy Board (the “OEB” or the “Board”) under the Ontario Energy Board Act, 1998 (the “Act”).

The utility develops and manages an electrical distribution network in the town of Chapleau, and delivers electricity to five customer classes via its distribution system: residential, commercial (small and large general service classes), street lighting, sentinel and unmetered scattered loads. CPUC earns income based on fixed and volumetric service charges for the distribution of this electricity. The service charges are set through a periodic rate making process via applications to the OEB.

The utility currently operates with revenues of $783,561 and has applied for a revenue requirement of $1,004,820 for the 2019 rate year. This projected revenue will form the base revenue requirement for rates during a 2019 to 2023 term of rates under the Board’s Renewed Regulatory Framework for Electricity Distributors (the “RRFE”). CPUC plans to use the incremental funds mainly to:

- Invest consistently and prudently in asset replacements such as poles.

- fund the costs associated with a 3rd party engineering firm to develop the Distribution System Plan required under the RRFE.
- Determining the necessary financial resources and workforce needs now and into the future.
- Improve communication with customers in accordance with the objectives of the RRFE.

1.1. Mission

CPUC operates a distribution network that supports Ontario's energy future by delivering on obligations mandated by the Ontario Government and other regulatory agencies. CPUC will continue to operate as a stand-alone LDC servicing community needs at a value for the money.

CPUC works collaboratively with customers and business partners to deliver cost-effective and reliable service with minimal interruptions to supply. CPUC employees act with integrity, maintain a safe environment and take responsibility for the community.

CPUC takes pride in servicing its customers and embraces its business values.

- Reliable – CPUC's System Reliability is a primary goal, designed to ensure appropriate management of its assets to provide a sustainable and reliable service to its customers.

- Safe – CPUC ensures that the safety of its staff and the public remains its number one priority over the planning period.

- Trustworthy – CPUC's employees are taking responsibility for their conduct and obligations to service their community.

- Asset Stewardship – CPUC's asset stewardship ensures continual enhancement of its asset management process as the basis for any increased investment.

- Customer Focused – CPUC effectively meets the service expectations to its customers and delivers a good value for the money.

- Collaborative – Decisions are made jointly, in cooperation with all stakeholders, as required, to optimize the planning process.

1.2. Strategic Goals and Initiatives (result)

CPUC has identified five key areas of focus that support the utility's mission:

- ✓ To provide safe, efficient, and reliable delivery of electricity to customers.
- ✓ To maintain costs at a reasonable level, find cost efficiencies wherever possible and to make prudent investments on behalf of its customers.
- ✓ To provide a safe and engaging work environment for its employees.
- ✓ To improve engagement with customers and the community.
- ✓ To plan and deliver system improvements required to ensure future supply.

1.3. Objectives (steps to get to the result)

CPUC plans on achieving its strategic goals by setting and meeting the following objectives:

- ✓ Make "reliability" a priority.
- ✓ Create a service-based utility whose primary goal is to exceed customers' expectations at a reasonable cost.
- ✓ Promote the long-term, efficient provision of utility services consistent with OEB policy.
- ✓ Work with other utilities in the promotion of both efficient and sustainable environment.
- ✓ Operate effectively with the staff currently in place.
- ✓ Reduce operational costs where and when possible.
- ✓ Develop and adopt an actionable plan to improve customer experience.

1.4. Utility Description

CPUC's service area is an embedded utility completely contained within the municipal boundaries of the town of Chapleau therefore the utility only serves the community of Chapleau. The area is embedded within the Hydro One Networks Inc. The map below shows the utility's service area. A more detailed PDF version of the map can be found at Appendix H of Exhibit 1.

In 2019, CPUC will rely on its approximately 30 km of circuits deliver approximately 26,173,316 kWh and 19,722 kW of energy to approximately 1,200 customers. CPUC`s distribution system is connected to the 115 kV transmission system through Chapleau DS. The distribution system is comprised of two voltage systems: one at 4.16 kV and the other at 25 kV. CPUC owns two 115-4.16 kV transformers at the DS totaling 6.2 MVA which supply 3 feeders. In addition, CPUC has one 25 kV feeder supplied by Hydro One Networks Inc. which is limited to supplying approximately 3.5 MVA of capacity. Approximately 60% of the distribution assets are rated at 4.16 kV and 40% are rated at 25 kV.

CPUC does not host any utilities within its service area, nor have any embedded utilities within its service area.

CPUC is a registered Market Participant dealing directly with the IESO. Details of the utility's capital assets are presented in the Distribution System Plan in Exhibit 2.

1.5. Utility Ownership

Chapleau PUC is licensed by the Ontario Energy Board to distribute electricity to the inhabitants of the Town of Chapleau. Chapleau PUC is incorporated under the Business Corporation Act on August 18, 1999. The sole Shareholder of Chapleau PUC is the Town of Chapleau. The population of the Municipality of Chapleau is approximately 2,000. The distribution service area within the Town of Chapleau is bounded by the township of Champlain, East Chapleau, and the province of Quebec.(are these correct?)

CPUC is a utility that is tasked with the delivery of electricity. Profits are either reinvested for infrastructure or distributed to its shareholder in the form of dividends.

2. Economic Overview and Customer Description

2.1 Economic Overview of the Service Area

CPUC's economic overview is also presented in section 2.1 of the Business Plan and duplicated below for ease of reference. A comprehensive community Profile published by the Town of Chapleau in March of 2016 is presented at Appendix I of this application.

Introduction
The Township of Chapleau is situated within the Boreal Forest and Arctic Watershed Region of Northern Ontario. Chapleau is best known for being the home of the world's largest Crown Game Preserve, as well as being the 2011 winners of WFN's Ultimate Fishing Town Canada contest. The Game Preserve, established in 1925, is 700,000 hectares in size, making it an exciting eco-tourism destination for world nature and wildlife travelers. Chapleau is also home to many different cultural communities, such as Chapleau Cree First Nation, Chapleau Ojibwe First Nation, Brunswick House First Nation, Chapleau's francophone community and Chapleau's Metis community. All of the various cultures have had a large impact on the history and upcoming of Chapleau. Deeply rooted in the fur trade and the railway, Chapleau's history began in 1885 when the Canadian Pacific Railway line provided access for the Hudson's Bay Company Trading Post. A fire in 1948 encouraged the government to develop a road so that logging contractors could remove the timber before it rotted. Consequently, Highway 129 was completed during the depression. In future years, Highways 101 and 17 were constructed to link Chapleau with Timmins to the East, and Wawa to the West (Wawa - 140 kilometres to the West and Timmins 200 kilometres to the East).

Location
Chapleau is linked to larger communities, such as Timmins , via highway 101, and to Sudbury and Sault Ste. Marie via highways 129 and 17. The Budd Car, operated by Via rail, offers train service travelling alternately east to Sudbury or west to White River with 2 stops per week in Chapleau. Travellers and residents can reach southern Ontario by Via Rail on the Canadian National Railway which stops regularly in Foleyet, which is one hour from Chapleau. International travel can be accommodated at Toronto Pearson international airport, with connecting regional air service to Timmins, Sault Ste. Marie, and Sudbury. Chapleau operates a municipal airport that is used for emergency services, and is host to the Ministry of Natural Resources base, which is used for fire suppression water bombers.

Climate
The average temperature fluctuates from a low of -16 degree Celsius in January to a high of 15.7 degree Celsius in August. From November 2017 to October 2018, Winter temperatures are expected to be above normal, with the coldest periods in mid-November, early and late December, early

January, and early and mid-February. Precipitation and snowfall are expected to be above normal in the east and below normal in the west, with the snowiest periods in late November, mid- and late December, and early to mid-March. April and May are expected to be a bit cooler than normal, with near-normal precipitation. Summer will be hotter than normal, with rainfall below normal in Southwest Ontario and above normal elsewhere. The hottest periods will be in early and late June, early July, and mid- to late August. September and October will be warmer and slightly drier than normal.

Labour Force

Chapleau is home to a labour force of 1,650 people. Median income levels are higher than the provincial average.

Participation rate % 60.3 is in line with 66.3 in Ontario. Employment rate % 53.9 in Chapleau vs. 61.3 in Ontario and Unemployment rate % 10.6 in Chapleau vs. 7.4 in Ontario.

The largest percentage of labour force (by industry) in Chapleau is employed in the Transportation and warehousing industry, which accounts for 23.5% of the labour force compared to 4.5% for Ontario. The percentage of labour force in the Health care and social assistance industry (13.3%) and in the Manufacturing industry (12%) locally are also high. The largest private sector Employers are Canadian Pacific Rail with 105 employees; Tembec with 168 Employees; True North Timber with 50 employees, Gold Corp with 43 employees and Chapleau Valu-mart with 37 employees. The largest public sector employers are Chapleau High School, Chapleau Health Services; Chapleau Child Care Centre; Ministry of Natural Resources and the Township of Chapleau.

3. Outcomes of the Renewed Regulatory Framework

On October 18, 2012, the Ontario Energy Board ("The Board") issued its "*Report of the Board: A Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*." The report set out a comprehensive performance-based approach for the Renewed Regulatory Framework which promotes the achievement of outcomes that;

- ✓ benefit existing and future customers
- ✓ align customer and distributor interests
- ✓ continue to support the achievement of important public policy objectives
- ✓ place a greater focus on delivering value for money

On March 5, 2014, the Board issued its report on "*Performance Measurement for Electricity Distributors: A Scorecard Approach*." The report set out the Board's policies on the measures that are to be used to assess a distributor's effectiveness and improvement in achieving customer focus, operational efficiencies, public policy responsiveness, and financial performance to the benefit of existing and future customers.

With the above in mind, the next section provides an account of how CPUC continues to improve in its understanding of the needs and expectations of its customers and its delivery of services.

3.1 Customer Focus

CPUC admits that customer focus has not been a priority in the past. However, in preparing the 2019 Cost of Service application, the utility has embraced the message from the RRFE and the values customer input and feedback can bring to a utility. Customers are engaged through education opportunities, surveys and directly by the utility for input on the main initiatives. Customer satisfaction is measured on the Distributor Scorecard as well as a bi-annual survey and then incorporated into goal setting and planning processes with a focus on ensuring and improving customer satisfaction.

CPUC's plan going forward is to improve lines of communication between the utility and its customers. CPUC is committed to helping customers make better choices and create healthy, sustainable results for the community it serves. CPUC has recently implemented a Customer Outreach and Outreach Plan in hopes that new customer engagement activities will result in feedback from its customers.

3.2 Seeking Customer Input

Customer satisfaction largely depends on whether a utility's products or services fulfill a customer's expectations—i.e., whether it meets, exceeds, or falls short of expectations. Quantifying customer satisfaction involves accumulating customer perceptions, measured through bi-annual surveys—in CPUC's case, using a 5- or 10-point scale, ranging from "poor" to "excellent. Customer Satisfaction Surveys are useful tools to understand how customers perceive the service they receive. CPUC is also embracing new ways to effectively connect with its customers such as the opening of a new Facebook and Twitter account, both launched in 2016-2017 to help with customer communications for outages, safety and during conservation campaigns.

In advance of its 2019 Cost of Service, the utility opened lines of communication with its customers to get valuable feedback on the utility's proposed capital and operational budget. The utility further engaged with its customers using the following activities.

- ✓ **<u>Press Release</u>**

  Press release distribution is an inexpensive method of reaching out to customers. When compared with paid advertising, press release distribution is almost always the more affordable option.

  CPUC also sees a press release as a way of boosting the company's visibility which is important for a small utility. A press release such as the one issued by CPUC let customers know who we are, what we do, and why they need us.

- ✓ **<u>Website Update</u>**

  The utility has updated its website to show it's current and upcoming capital projects. This new section of the website will be updated monthly so that CPUC's customers can understand and comment on the utility's decision regarding its operational and capital planning.

- ✓ **<u>Info letter via bill insert</u>**

  Bill inserts are an excellent way to communicate relevant information to our customers. CPUCs has created an electronic letter which was posted on Facebook and Twitter.

3.3 Alignment of Goals to Needs and Preference of Customers

CPUC's customer satisfaction results and finding based on discussions with its customers supports the valid hypothesis that good service—i.e., high levels of reliability, or low SAIDI— combined with reasonable prices are essential to satisfying customers. In other words, all customers expect reliable service at the lowest prices possible.

High level of reliability requires system-wide investments - notably enhancing the distribution system to provide more reliable service can be expensive. Much like other utilities, CPUC must frequently consider trade-offs between costs and benefits; that is, to target initiatives that will provide the biggest bang—or increase in customer satisfaction.

The survey results helped to identify customer attitudes about the utility's conservation programs, smart meters and TOU rates, electricity prices and CPUC's standing and reputation in the community. The results will assist CPUC in fine tuning its programs, services and communications use direct and reliable customer feedback. CPUC's goal going forward will be to develop and communicate an actionable plan to continuously improve its communication with its customers during power outages, regardless of the cause.

In advance of its 2019 Cost of Service, CPUC has reached out to its customers seeking feedback and input on their views and preferences.

Although the utility did not receive much feedback from its customers, CPUC is confident that with the communication plan in place, the utility's capital budget, as proposed in the Distribution System Plan, supports CPUC's customer priority and preferences. The priority going forward is to maintain CPUC's distribution assets in proper order and manage its distribution system so that the utility can provide electricity to its customers in a reliable and responsible manner. Other priorities involve maintenance of its poles and meters at a steady pace to minimize rate shock.

CPUC is committed to providing its employees and third party contractors which represents the utility, with a safe and injury-free workplace as well as delivering its services in a manner that ensures both customer and public safety. CPUC's customers have high expectations of reliability and CPUC strives to meet and exceed those expectations on a daily basis, now and into the future, as demonstrated by CPUC's comprehensive Distribution System Plan.

3.4 Public Policy Responsiveness

The Conservation and Demand Management Requirement Guidelines for Electricity Distributors (EB-2014-0278, the "2015 CDM Guidelines"), issued by the OEB on December 19, 2014, are applicable to CDM programs beginning January 1, 2015. These guidelines require distributors to continue to rely on the LRAMVA to track and dispose of lost revenues that result from approved CDM programs between 2015 and 2020. The IESO provides funding for CPUC's CDM programs. CPUC's funding portfolio for 2015 to 2020 is $298,764 and 1,045,702 kWh for the 2015-2020 period. As of end of June 2018, Chapleau PUC has achieved 698,929 kWh of savings, which represents 67% of its overall target. As such, Chapleau PUC is well poised at the end of year two of conservation framework.

Portfolio delivery activities in 2017 show that Conservation First continues to deliver strong results, support current participants, and maintain our focused outreach efforts to engage with new participants and foster additional applications. Furthermore, we expect that the launch of new Province Wide Programs will help deliver additional savings.

Conservation Report

2015-2017 Final Verified Results

At the end of 2017, Chapleau PUC achieved 698,929 kWh of savings towards their 2015-2020 Conservation First Framework (CFF) target. This represents 67% savings towards the overall target of 1,045,702 kWh. Chapleau PUC has two Multi-Site Applications and an additional two Township of Chapleau Retrofit applications in the pipeline, all of which are expected to complete in 2018-2019. These pipeline applications should generate an additional 247,923 kWh savings and will put Chapleau close to 90% towards overall target. CustomerFirst continues to work with local contractors, business and residents to advertise programs available, as well as generate new local program offerings such as the Instant Savings Program – Clothesline give-a-way.

Table 1: Chapleau PUC Allocated Target and Budget

2015-2020 CFF Target (kWh)	1,045,702
2015-2020 CFF Budget ($)	$ 298,764

Table 2: Progress toward 2015-2020 CFF Target and Budget Spent

	2015	2016	2017	2015-2017 Verified Results (kWh)	Progress toward CFF Target
Net Verified Annual Savings (kWh)	278,924	211,864	208,141	698,929	67%
Total Spending ($)	$ 3,356	$ 19,889	$ 42,176	$ 65,421	22%

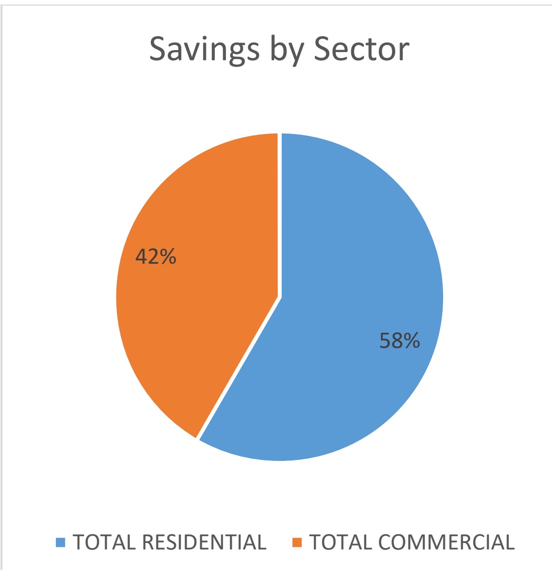
Table 3: Participation and Savings by program

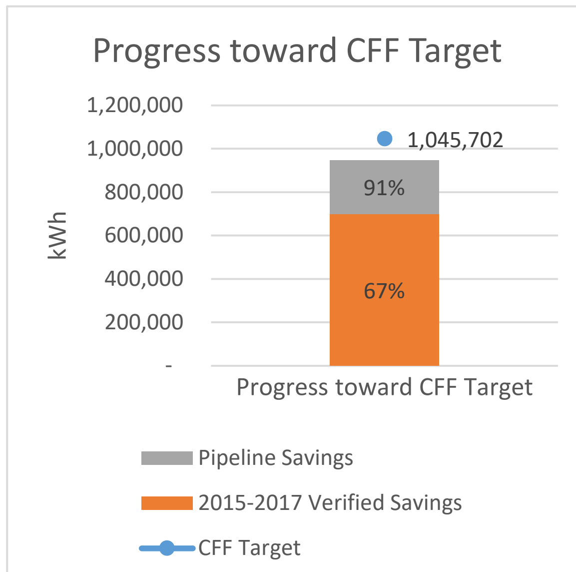
	Participation			2020 Annual Energy Savings (kWh)		
Residential Programs	**2015**	**2016**	**2017**	**2015**	**2016**	**2017**
Coupon/Instant Discounts	940	4996	7746	22,044	149,388	196,955
Appliance Retirement	1					
Bi-Annual Retailer Event	1473			34,822		1,056
Heating and Cooling Incentive			1			
Whole Home Pilot			8			3,593
TOTAL RESIDENTIAL				56,866	149,388	201,604
Commercial Programs	**2015**	**2016**	**2017**	**2015**	**2016**	**2017**
Retrofit	3	2	1	218,983	62,476	6,537
Small Business Lighting	1			3,075		
TOTAL COMMERCIAL				222,058	62,476	6,537

TOTAL PORTFOLIO	278,924	211,864	208,141

Table 4: Savings Pipeline

RETROFIT	ID	Incentive	Savings (kWh)	Estimated In-Service
Liquor Control Board of Ontario	192,771	$ 3,520.00	3,320	30-Sep-18
Township of Chapleau (Streetlights)	190,859	$ 15,700.00	183,313	2-Jan-19
Township of Chapleau (Curling Rink)	193,892	$ 4,208.34	51,327	28-May-18
RBC Bank	194,768	$ 550.00	5,053	22-Sep-18
The Beer Store - 2363	190,708	$ 2,972.80	4,909	20-Oct-17
TOTAL PIPELINE		$ 26,951.14	247,923	





3.5 Financial Performance

CPUC has recently put in place financial performance checks to ensure solid performance going forward. Key factors to this financial success are effective business planning, a continuous focus on operational efficiency, and managing capital and expense expenditures to budget. The Business Plan and Distribution System Plan will serve a major role in providing the future direction of financial investment and performance. Financial Results are discussed in detail in Section 8 of this Business Plan.

4. Performance Metrics and Benchmarking

Another development that has brought utility customer satisfaction to the forefront is the use of benchmarking studies, which compare levels of customer satisfaction across utilities.
High scores in benchmarking studies can show that utilities are recognized as being the best in class.

Perhaps the most widely-known benchmark of efficiency rating comes from the PEG report which surveys all 71 utilities in Ontario. The PEG analysis is one of the only instruments that compares utilities' cost efficiencies on a consistent basis and is publicly available.

PEG produces an annual report that provides a ranking of the utilities included in the study, summarizes the results, and provides insight into the trends in utility efficiency scoring.

As a consequence of this study, CPUC has expended considerable effort to understand the drivers of their efficiency ranking and has undertaken initiatives to improve their scores.
The following section reviews past performances and introduces future performances based on load forecast and forecasted capital and operational expenditures.

4.1 Past performances

The PEG Past Performance table below shows CPUC's rating for the last three historical years of business. The PEG report uses econometrics to determine the cost efficiency of distributors. Group 1 (of 5) is ranked as the most efficient group.

Table 1 - PEG Past Performance (Stretch Factor)

	2014	2015	2016	2017
Stretch Factor Cohort - Annual Result	4	4	4	4

The percentage difference between actual and predicted cost is the measure of cost performance. Utilities with larger negative differences between actual and predicted costs, such as CPUC, are better cost performers and therefore eligible for lower stretch factors. This table shows CPUC's difference between its actual costs and predicted, and although total costs have increased, costs performances are improving.

Table 2 - Summary of Cost Performance Results

	2014	2015	2016	2017
	(History)	**(History)**	**(History)**	**(History)**
Cost Benchmarking Summary				
Actual Total Cost	899,874	902,761	922,404	888,710
Predicted Total Cost	682,181	711,003	747,552	757,964
Difference	217,693	191,758	174,852	130,746
Percentage Difference (Cost Performance)	27.70%	23.88%	21.02%	15.9%
Stretch Factor Cohort - Annual Result	4	4	4	4

The utility's historical capital additions have also been historically stable which has been achieved using a solid well tracked budget process.

Table 3 - Historical Capital Spending

	2014	2015	2016	2017
Capital Additions	$43,923	$101,176	$36,293	$24,057

The utility's Rate Base has increased proportionally to its capital investments and as such has remained historically as stable as its other financial metrics.

Table 4 - Historical Revenues

	Year	2014	2015	2016	2017
Residential	Fixed	$23.77	$24.04	$24.04	$24.04
	Variable	$0.0138	$0.0140	$0.0140	$0.0140
	Cust/Conn	1,063	1,059	1,059	1,054
	kWh	15,225,943	13,727,288	12,612,066	12,775,802
	Revenues	$513,185.51	$497,538.11	$481,925.00	$482,919.15
General Service < 50 kW	Fixed	$34.78	$35.18	$35.18	$35.18
	Variable	$0.0177	$0.0179	$0.0179	$0.0179
	Cust/Conn	152	152	157	152
	kWh	5,251,375	4,907,587	4,617,295	4,702,580
	Revenues	$156,179.38	$152,014.13	$148,717.62	$148,344.50
General Service > 50 kW - 4999 kW	Fixed	$34.78	$193.66	$193.66	$193.66
	Variable	$3.5875	$3.6185	$3.6185	$3.6185
	Cust/Conn	10	11	12	15
	kWh	7,157,299	6,867,603	7,048,334	6,797,046
	kW	20,149	18,062	18,740	17,522
	Revenues	$72,693.51	$65,834.99	$68,331.75	$64,054.69
Unmetered Scattered Load	Fixed	$24.71	$24.99	$24.99	$24.99
	Variable	$0.0332	$0.0336	$0.0336	$0.0336
	Cust/Conn	4	4	4	4
	kWh	4,068	2,892	2,892	2,892
	Revenues	$1,321	$1,297	$1,297	$1,297
Sentinel	Fixed	$7.84	$8.65	$8.65	$8.65
	Variable	$13.6395	$15.0437	$15.0437	$15.0437
	Cust/Conn	23	23	23	23

	kWh	26,857	23,735	19,993	20,629
	kW	75	63	60	62
	Revenues	$4,787.46	$5,099.81	$5,054.68	$5,084.77
Streetlighting	Fixed	$4.38	$4.43	$4.43	$4.43
	Variable	$20.3873	$20.6218	$20.6218	$20.6218
	Cust/Conn	328	328	328	328
	kWh	274,528	274,259	274,259	274,259
	kW	768	768	768	768
	Revenues	$95,901.86	$97,004.95	$97,004.95	$97,004.95
Total	**Cust/Conn**	**1,579**	**1,577**	**1,582**	**1,576**
	kWh	**27,940,070**	**25,803,364**	**24,574,839**	**24,573,208**
	kW	**691,678**	**669,742**	**651,507**	**650,912**
	$	**$844,068.86**	**$818,788.68**	**$802,330.70**	**$798,704.75**

The utility’s revenues per class and overall revenues have also been historically steady.

4.2 Target Performance

This section summarizes the projected performance of the utility taking into consideration the long-term perspective of the health and age of the distribution assets. It captures the results of CPUC's expected PEG performance, Rate Base and projected revenues based on its priorities for capital investments and operational expenditures.

Table 5 - PEG Target Performance (Stretch Factor)

	2018	2018
Stretch Factor Cohort - Annual Result	5	5

Table 6 - Target Cost Performance Results

	2018	2019
Cost Benchmarking Summary		
Actual Total Cost	1,021,402	1,028,300
Predicted Total Cost	767,637	777,981
Difference	253,765	250,318
Percentage Difference (Cost Performance)	28.6%	27.90%
Stretch Factor Cohort - Annual Result	5	5

Table 7 - Proposed Capital Additions for 2018-2019

	2018	2019
Capital Additions	476,662	80,667

Table 8 - Proposed Revenues by Class

	Year	**2018**	**2019**
Residential	Fixed	$24.04	$50.87
	Variable	$0.0140	-$0.0000
	Cust/Conn	1,043	1,033
	kWh	13,990,554	13,831,681
	Revenues	$496,893.29	$630,628.67
General Service < 50 kW	Fixed	$35.18	$35.18
	Variable	$0.0179	$0.0266
	Cust/Conn	150	148
	kWh	4,979,438	4,880,502
	Revenues	$152,548.80	$192,398.88
General Service > 50 kW - 4999 kW	Fixed	$193.66	$193.66
	Variable	$3.6185	$5.1694
	Cust/Conn	15	15
	kWh	7,189,214	7,147,174
	kW	18,883	18,883
	Revenues	$68,985.61	$133,012.04
Unmetered Scattered Load	Fixed	$24.99	$21.17
	Variable	$0.0336	$0.0285

	Cust/Conn	4	4
	kWh	5,232	5,232
	Revenues	$1,375	$1,165
Sentinel	Fixed	$8.65	$12.32
	Variable	$15.0437	$21.4320
	Cust/Conn	23	23
	kWh	24,760	24,760
	kW	65	65
	Revenues	$5,129.90	$4,794.28
Streetlighting	Fixed	$4.43	$5.68
	Variable	$20.6218	$26.4451
	Cust/Conn	328	328
	kWh	283,967	283,967
	kW	774	774
	Revenues	$97,128.68	$42,820.79
Total	**Cust/Conn**	**1,564**	**1,552**
	kWh	**26,473,166**	**26,173,316**
	kW	**670,540**	**843,914**
	$	$822,061.59	$1,004,819.58

4.3 Short and Long-Term Capital Spending

CPUC is focused on maintaining its high-performance levels in all aspects of its capital investments and planning activities to comply with its regulatory obligations and responsibilities to the Ontario Energy Board (OEB) and the Electrical Safety Authority (ESA).

At the core of CPUC's mandate, is the responsibility to deliver a trusted source of safe, efficient, and reliable power to its customers, which supports growth and accommodates economic development in the town of Chapleau.

CPUC strives to provide safe, reliable service while minimizing the life cycle costs of assets by doing predictive and preventative work. CPUC places a high priority on the upkeep and replacement of its aging infrastructure. Distribution equipment that was placed in-service many years ago, in many cases, has reached its normal useful life. Therefore, CPUC is faced with the ongoing replacement of this aging infrastructure. Customer expectations for reliability are high and can only be met with a well-maintained distribution system. Thus, investment in replacement equipment along with its associated operational costs has become a continuous reality for CPUC as it commits to satisfying the essential community needs.

Table 6 – Table of Major Capital Projects for 2018-2022

Forecast period	**2019**	**2020**	**2021**	**2022**	**2023**	**Total**
Feeder/Station Conversion 20-year Plan	$80,667	$80,667	$80,667	$80,667	$80,667	$80,667

2018-2019 Capital Planning

A newly developed Distribution System Plan forms the basis for the utility's capital and maintenance programs. The Distribution System Plan reflects the latest performance priorities of the distribution system and serves as a placeholder for the longer-term projects recommended from the condition (age risk ratings) assessments.

Priorities and strategies for budget development include the following:

- Maintenance of an aging transformer through various forms of monitoring and testing ensuring that the asset can remain in service until the next Cost of Service application.
- Replacement of poles and transformers as they show sign of deterioration

5-10 Year Capital Planning to Accommodate Aging Infrastructure

Under a 5-10-year capital investment plan, the company has embarked on a prudent course to maintain the utility's equipment assets.

CPUC places a high priority on balancing its obligations to accommodate growth while addressing the upkeep and replacement of its aging infrastructure. The following are the actions that CPUC plans to take over the next 5-10 years to bring about the desired future.

- Priority will be given to CPUC's legislated/mandatory requirements; for example:
  - System access including the obligation to connect customers – mostly Residential, but Commercial as well.
  - Accommodate City, Region, Ministry, etc. mandatory project requirements.
  - Meet the OEB's – and other regulatory bodies' – quality, reliability, health, safety, environmental, etc. performance standards.
- To safeguard the major investments already made in its critical assets and continue to maintain and upgrade as necessary.
- Continue to invest prudently in modern information technology to provide customers with clear, meaningful bills that can assist them in managing their electricity usage.
- Optimal life extension, for example:
  - Intensify condition monitoring to minimize uncertainty regarding decisions relating to equipment maintenance, renewal, and replacement.
  - Where economically viable, refurbish cables and equipment in-situ to extend their reliable useful lives.

Feeder/Station Conversion 20-year Plan

All poles originally installed for 4kV feeders will need to replace to support 25kV feeders. The estimated number of poles and cables is based on CPUC's line diagram and counting the approximate amount of poles on the 4kV feeders.

In Years 1-5 (2019-2023), poles that are "failed" are replaced with the historical replacement rate of 6 poles and the remaining poles for replacement are targeted mostly on feeder F2. This sums up to 14 poles per year.

In Years 6-10 (2024-2028), continue with pole replacement program and increase the count of poles replaced by 2028 to complete all pole replacements on F2 and to begin pole replacements on F9. Ideally, the pole replacements on F9 would begin late 2026. In 2026, the station that feeds into F2 is rebuilt and presents the option to move the load off Hydro One's 25kV feeder. Near the end of this term and beginning of the next five-year block, the F9 feeder can be converted to a hybrid 25kV/4kV system with the use of conversion transformers. Targeting feeder F9 over feeder F8 is advantageous and beneficial for CUCP because it would improve the losses experienced on the system faster, since majority of losses are experienced on F9.

In Years 11-15 (2029-2033), pole replacement continues for F9 and will begin for F8 mid period. The underlying assumption still runs that 6 poles/year are "failed" and require replacement, with the remaining poles in the replacement plan are targeted for feeder F9 primarily, and once completed followed by poles on feeder F8. By 2032, majority if not all poles on F9 should be replaced allowing for the conversion of the second transformer.

In Years 16-20 (2034-2038), pole replacement is steady with the remaining poles on feeder F8 decreasing. By the end of the 20-year plan, feeder F8 will converted to the 25kV system with very few poles remaining. Pole replacement will return to replacing "fail" poles based on condition assessment and service requests in the next DSP period.

4.4 Operational Costs

CPUC's Operations strategy is to provide safe, reliable service at an appropriate level of quality throughout the licensed service areas.

CPUC continually reviews its business and operational goals against its workforce needs, its financial strength and the impact on its customers. CPUC recognizes the importance and value of maintaining a skilled and engaged workforce, where all employees are customer focused and enjoy working for the utility. CPUC's analyzes its operation budget on a monthly basis as to not stray far from its budgets thus ensuring that its ROE stays within range of its approved ROE. The utility is very mindful that every dollar of increase in operation costs means that a dollar more is collected from the customers. Therefore, operational planning focuses mainly on efficiency and finding reductions wherever possible. Historical and projected costs are shown in Table 10 below.

Table 9 – Operating Costs

	Board Approved	2012	2013	2014	2015	2016	2017	2018	2019
Operations	$205,440	$289,711	$220,412	$223,211	$208,239	$236,332	$237,909	$247,400	$242,760
Maintenance	$0	$0	$0	$0	$0	$0	$0	$0	$1,610
SubTotal	**$205,440**	**$289,711**	**$220,412**	**$223,211**	**$208,239**	**$236,332**	**$237,909**	**$247,400**	**$244,370**
%Change (year over year)		41.0%	-23.9%	1.3%	-6.7%	13.5%	0.7%	4.7%	-1.2%
%Change (Test Year vs Last Rebasing Year - Actual)									-15.7%
Billing and Collecting	$84,200	$95,585	$115,086	$135,609	$129,895	$121,157	$121,220	$135,000	$133,730
Community Relations	$600	$115	$415	$415	$115	$415	$415	$0	$0
Administrative and General+LEAP	$354,100	$285,195	$302,558	$385,438	$392,316	$386,133	$357,042	$427,004	$443,063
SubTotal	**$438,900**	**$380,896**	**$418,059**	**$521,463**	**$522,325**	**$507,705**	**$478,677**	**$562,004**	**$576,793**
%Change (year over year)		-13.2%	9.8%	24.7%	0.2%	-2.8%	-5.7%	10.7%	2.6%
%Change (Test Year vs Last Rebasing Year - Actual)									51.4%
Total	**$644,340**	**$670,607**	**$638,471**	**$744,673**	**$730,565**	**$744,037**	**$716,586**	**$809,404**	**$821,163**
%Change (year over year)		4.1%	-4.8%	16.6%	-1.9%	1.8%	-3.7%	13.0%	1.5%

4.5

4.6 Return on Equity

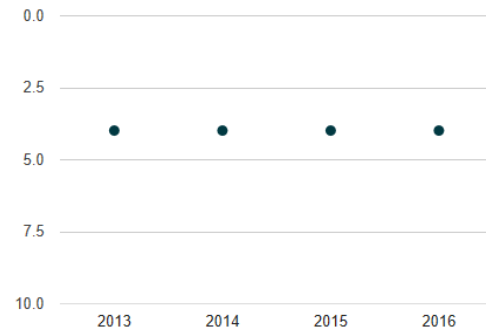
The actual Return on Equity for 2016 is -3.82% which indicates an under earning when compared to the Board Approved 2012 rate of return. Further information on the topic of Return on Equity can be found in Section 7.

4.7 Scorecard Results and Analysis

Efficiency rating

4 (2016)

The utility must manage its costs successfully in order to help assure its customers they are receiving value for the cost of the service they receive. Utilities' total costs are evaluated to produce a single efficiency ranking. This is divided into five groups based on how big the difference is between each utility's actual and predicted costs. Distributors whose actual costs are lower than their predicted costs are considered more efficient.



1 = Actual costs are 25% or more below predicted costs

2 = Actual costs are 10% to 25% below predicted costs

3 = Actual costs are within +/- 10% of predicted costs

4 = Actual costs are 10% to 25% above predicted costs

5 = Actual costs are 25% or more above predicted costs

Service Quality

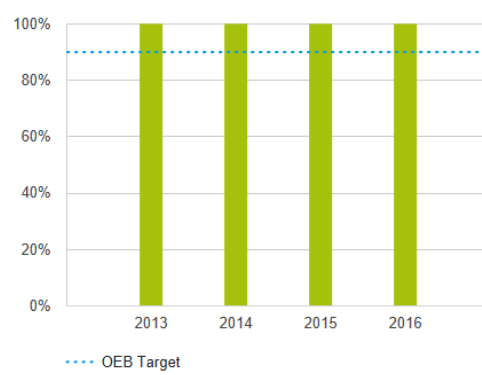
From the period of 2011-2014, the utility 's results were recorded as 100%; Despite its perfect results, the utility along with neighbouring utilities has implemented new process in place. CPUC expects that over time its results should remain strong.

SERVICE QUALITY

New residential/small business services connected on time

100% (2016)

The utility must connect new service for the customer within five business days, 90 % of the time, unless the customer agrees to a later date. This timeline depends on the customer meeting specific requirements ahead of time (such as no electrical safety concerns in the building, customer's payment information complete, etc.)



Target met

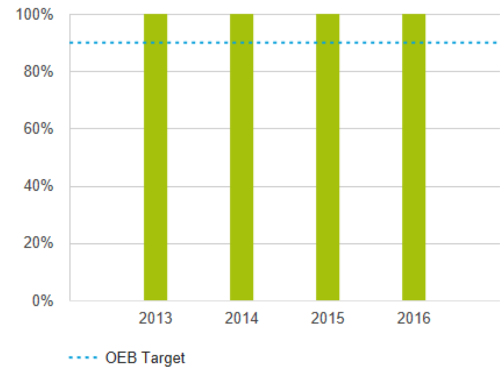
SERVICE QUALITY

Scheduled appointments met on time

100% (2016)

For appointments during the utility's regular business hours, the utility must offer a window of time that is not more than four hours long, and must arrive within that window, 90 % of the time.

✓ Target met



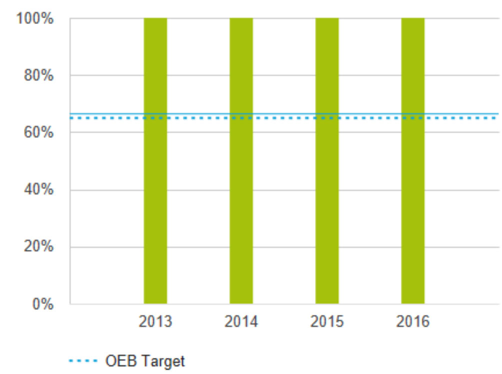
SERVICE QUALITY

Telephone calls answered on time

100% (2016)

During regular call centre hours, the utility's call centre staff must answer within 30 seconds of receiving the call directly or having the call transferred to them, 65 % of the time

✓ Target met



Customer Satisfaction

CPUC conducted its bi-annual customer satisfaction survey in Spring 2015 and then again in the spring of 2017 in advance of the Cost of Service. The results are presented at Section 1.8 of this Exhibit. Customers are generally satisfied with CPUC as reported in the Customer Satisfaction Survey (not yet reported on the Scorecards), which show a satisfaction rate of 95%. While CPUC manages less than 15% of the total customer bill it continues its efforts to maintain appropriate cost control while providing a safe and reliable delivery of power to its customers. First Contact resolution has remained high over the period of 2014-2015 as has the Billing Accuracy with results of 99.99% in 2015 and 99.99% in 2016.

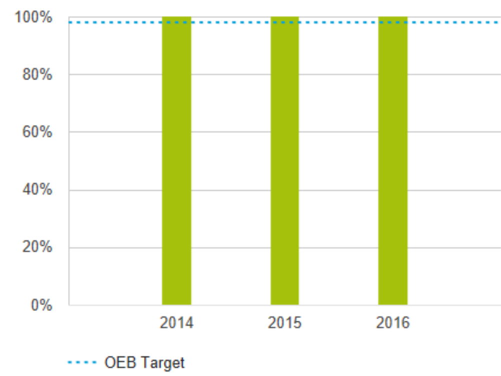
Billing accuracy

99.99% (2016)

An important part of business is ensuring that customer's bills are accurate. The utility must report on its success at issuing accurate bills to its customers.

More information about billing accuracy

Target met



Complaints

0.80 (2016)

This metric measures the number of complaints the Ontario Energy Board received from customers about matters within our authority. Complaints made directly to the utility are not reported here. We measure this per 1000 customers so utilities that serve much larger or smaller populations can be compared against each other.

Year	Complaints per 1000 customers	Total number of complaints
2013	0.00	0
2014	0.00	0
2015	0.00	0
2016	0.80	1

Safety

Safety remains a core attribute of CPUC's as it delivers power to its employees and customers daily. CPUC continues to strive to communicate on safety throughout our distribution system through various methods including safety orientations, on-line, outreach, and telephone. Results over the past 5 years shows no Serious Electrical Incident Index.

System Reliability

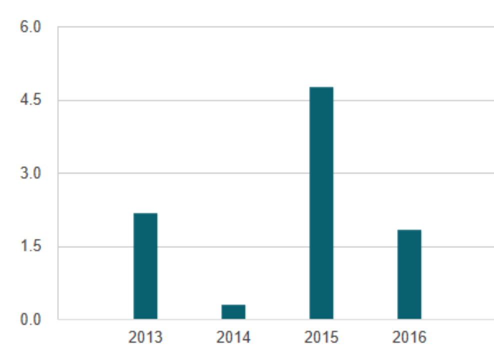
The reliability of the system remains a cornerstone of CPUC with attention distribution system infrastructure. Most interruptions continue to be because of increased storm activity. 2011 showed abnormally high indicators however, 2012-2015 show excellent results.

SYSTEM RELIABILITY

Average number of hours power to a customer was interrupted

1.8224h (2016)

An important feature of a reliable distribution system is recovering from power outages as quickly as possible. The utility must track the average length of time, in hours, that its customers have experienced a power outage over the past year.



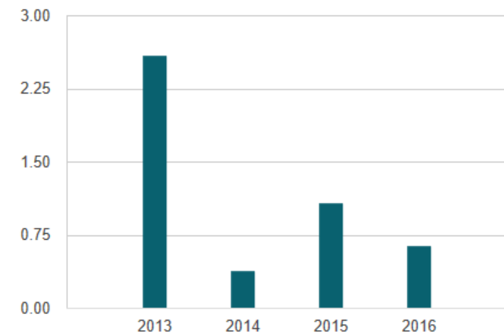
SYSTEM RELIABILITY

Average number of times power to a customer was interrupted

0.6328 (2016)

Another important feature of a reliable distribution system is reducing the frequency of power outages. Utilities must also track the number of times their customers experienced a power outage during the past year.

More information about interruption frequency



Asset Management

The Distribution System Plan detailing the utility's historical and projected capital plan can be found in Exhibit 2 of this application.

Cost Control

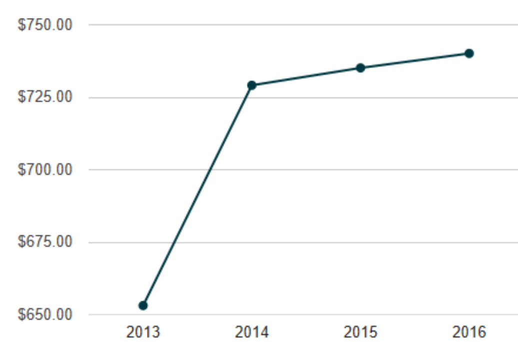
CPUC has maintain its group 1 efficiency assessment report for many years (since 2006). Despite having achieved the highest efficiency grouping, CPUC continues to strive to achieve greater efficiency through productivity improvements and cost control, without compromising safety and reliability. The utility intends on maintaining its Group 1 efficiency form the next rate period.

Cost per customer

$740 (2016)

A simple measure that can be used as a comparison with other utilities is the utility's total cost per customer.

Total cost is a sum of all the costs incurred by the utility to provide service to its customers. The amount is then divided by the utility's total number of customers. This amount does not represent how much customers pay for their utility services.



Conservation & Demand Management

Under the new regulations, CPUC has developed a CDM plan to meet the 2015-2020 energy targets under the Conservation First Framework. CPUC has submitted and received approval from the IESO on the Conservation First Framework 2015- 2020 CDM Plan. The CDM plan has being filed in conjunction with this application.

Connection of Renewable Generation

CPUC does not currently have any renewable energy or Microfit installation. Despite the lack of participation in the MicroFit program, CPUC continues to work with Customer First to advertise renewable energy and encourage conservation.

Financial Ratios

CPUC financial ratios are discussed in detail at Section 7 of this Business Plan.

4.8 Future Outlook

"It is said that you learn more from mistakes than successes. Even the most successful companies have a litany of stories about bad business decisions and bad investments, choosing to work with the wrong people, and so many times where they knew better, but failed to act appropriately. It appears that failure is inevitable. The key to success is what you make of your failures."

CPUC has learned vital financial and management lessons through the hands-on preparation of the 2019 Cost of Service application.

CPUC strives to Institute a culture of continuous self-improvement identifying areas where the effectiveness of the organization can be improved.

CPUC was restructured into a fully operational utility on January 1, 2018. Prior to this it had been run and regulated as a virtual utility owning most but not all assets required to conduct business and having no dedicated staff. The restructuring required the transfer of the remainder of the property, plant and equipment assets necessary to carrying out utility business and these assets were transferred at fair value. The transferred assets consisted of office furniture and equipment, computer hardware and software, transportation equipment and tools, tools and equipment. Additionally, all 5 employees were also transferred into CPUC.

In 2017, CPUC took steps to weave reliability and sustainability into all aspects of its operations – from the power supply to encouraging and helping customers incorporate green features into their homes and businesses. Even though CPUC is a small utility, planning is something it has always done well and will continue to do so in the coming years.

CPUC also set out to leverage social media to improve the customer experience. Since then, the utility has launched a series of technology enhancements to increase communication with its customers and plans to upgrade its website in 2019/2020 to include capital projects and educational tools about the industry and regulatory processes.

CPUC will continue to monitor its business objectives to ensure that they are aligned with the OEB scorecard and actively drive cost reductions and productivity improvement.

Crafting the herein Business Plan has been a worthwhile exercise in that it assisted CPUC in thinking about how to plan and implement quick wins, mid-term improvements, and longer-term improvements.

Some of the self-assessment measures which informed CPUC's Business Plan include;

- ✓ Reviewing its mission statement to ensure that it informs the direction of the utility and serve as a guide for long-term growth/development.
- ✓ Detailing specific long-term goals and short-term objectives by developing an action plan for each goal and objective.
- ✓ Reviewing its current management structure, including the roles and responsibilities management team and employees. In doing so, CPUC reviewed areas for improvement in the current management structure to better understand its obstacles.
- ✓ Analyzing its economic conditions to better understand its effect on business strategy – including consideration for load forecast, predicted capital and operational costs, resources.
- ✓ Analyzing its strengths and weaknesses to identify where it is the most vulnerable.

5. Strategy and Implementation Summary

5.1 SWOT Analysis

The use of the SWOT (strengths, weaknesses, opportunities, and threats) analysis is new to the utility, however it has already proven to be a valuable management tool that has helped CPUC review key aspects of the utility to identify factors that will drive performance and decision making going forward.

Strengths and Weaknesses are associated with i<u>nternal</u> factors such as:

- ✓ Financial resources, such as funding and ability to meet its financial obligations.
- ✓ Physical resources, such as the utility's location, facilities, and equipment.
- ✓ Human resources, such as employees, volunteers, and target audiences
- ✓ Access to natural resources, trademarks, patents and copyrights
- ✓ Current processes, such as employee programs, department hierarchies, and software systems

Opportunities and Threats are associated with <u>external</u> factors such as:

- ✓ Market trends such as new products and technology or shifts in audience needs
- ✓ Economic trends, such as local, national and international financial trends
- ✓ Funding, such as donations, legislature, and other sources
- ✓ Demographics, such as a target audience's age, race, gender and culture
- ✓ Political, environmental and economic regulations.

5.2 CPUC Strengths

Personal Edge

While the values of top management have a significant impact on the performance of businesses of all sizes, in small businesses, social performance is more directly and personally shaped by management. A smaller town with a smaller utility such as CPUC is more socially and economically embedded within the community in which they operate than are managers of big utilities. Managers of a small utility are more likely to live in the city or town where they conduct business. They are long term residents. Their children attend local schools and play in local parks. Their families personally benefit from safe streets and vital community. The absence of an infrastructure that exists in larger cities increases the business' motivation to work for general community betterment. Long-term residence in a town is associated with knowing a greater number of other residents, interacting with them in multiple venues (as church members, employees, neighbours, and friends), and knowing more residents beyond the acquaintanceship level. Each relationship represents a potential personal invitation to get involved in a community organization and to engage with customers. If the community has a pattern of residents working together to promote community betterment, the more people a business owner knows, the greater the likelihood he or she will be personally invited to get involved in community projects or this case, have a voice and an opinion that is sure to be heard. In smaller towns such as Chapleau, customer engagement is not always done at the utility's head office; it is often done at while waiting in line at the grocery store, bank or the gas pump.

When customers personally know (and like) the employees, they're more likely to support the idea of having and keeping it local utility in business. CPUC has the advantage of knowing its customers face-to-face thus providing the utility with an inherent customer engagement in its day to day operation. Getting to know customers face-to-face is a natural and important outreach strategy.

Employees

CPUC cares about its employees, always ensuring a safe work environment, with opportunities for personal growth and development, and fair remuneration and management practices.

CPUC's management team also strives to lead by example. What this means is that active participation by the general manager promotes and encourages employee learning, engagement, and participation. CPUC understands that having the right team in place is critical to the success of the business and such dynamics can only be achieved when a utility invests in its employees. Studies show that high levels of employee engagement in an organization are linked to superior business performance, including increased employee retention & profitability, customer excellence, and safety performance.

Going forward, the utility will continue to identify the key gaps between the talent in place and the talent required to drive business success and provides clear expectations and feedback to manage performance.

✓ New Management, fresh start

CPUC has put in place budget checks and balances, trends and performances analysis and now makes decisions that help manage the cost, reliability, and availability of electricity supply to its customers in the long term.

Customers and Community

CPUC values the input and feedback of its customers and partners and respects the needs and expectations of its customers. CPUC takes pride in making significant contributions to its community programs in which we can add value such as fundraising, energy conservation projects and business development activities.

5.3 CPUC Weaknesses

- ✓ **Dependency on third party assistance to meet its regulatory requirements.**

  CPUC has statutory obligations and responsibilities to the Ontario Energy Board (OEB) and the Electrical Safety Authority (ESA). Both regulator issue comprehensive OEB codes and guidelines that come with compliance and reporting requirements. As a small utility with only 3 administrative employees, it can be difficult to conform to an ever-changing regulatory environment. Planning and budgeting for the unexpected can be difficult – especially with the current five-year rate rebasing period. CPUC is also finding that much of the new requirements require expertise which goes beyond those of its current staff and as such, the utility must often turn to third-party experts (such is the case for the DSP) to bring external expertise to meet the requirements and level of standards which regulators expect. Under those circumstances, the utility will often "shop around" and negotiate rates and costs to find the best value for money.

- ✓ **Managing unexpected costs beyond the utility's control.**

  As mentioned in the section above, planning and budgeting for the unexpected can be difficult – especially with the current five-year rate rebasing period. For the most part, the utility plans for significant investments well in advance, however, unexpected costs can arise as a result of a change in legislation or new regulatory requirements. Most larger utilities can absorb these costs without much impact on rates or performance. However, as smaller utility, CPUC can be materially affected when faced with cost pressures that are beyond its control or ability to plan for.

- ✓ **Trying to keeping up with standards designed for larger utilities.**

  The industry assumption is that small utilities should adopt the same management principles as big utilities, only on a smaller scale. Underlying that assumption is the notion that small utilities are the same as larger utilities, except with lower revenues, lesser assets, and fewer employees.

For one thing, management salary in a small utilities represents a much larger fraction of costs than in a larger utility, often such a large fraction that little is left over to pay additional managers or to provide dividends to the shareholder. Similarly, small utilities cannot usually afford to pay for external resources they need, nor can new employees be adequately trained to do their duties.

In addition, external forces tend to have more impact on small utilities than on large utilities. Changes in government regulations, tax laws, and labour and interest rates usually affect a greater percentage of expenses for small utilities than they do for large corporations.

In anticipation of an on-going disproportion in ratios, CPUC has put special financial management tools in place to make the most efficient and practical use of their resources.

- ✓ **Aging community**

Chapleau tends to be home to a fairly mature community whose primary source of communication is newspaper rather than social media which can eliminate cost efficient customer engagement option.

5.4 CPUC Opportunities

- ✓ To form strategic alliances with like-minded LDCs to realize greater efficiencies and integrate new ideas that improve operations and ensure sustainability in an evolving energy sector.
- ✓ To drive down operating costs as much as possible.
- ✓ To meet and monitor the utility’s allocated Conservation targets as closely as possible.
- ✓ To position the utility as a reliable and customer-focused LDC, with high levels of trust
- ✓ To disaffirm negative perceptions that prevail, particularly in respect to energy increases
- ✓ To build a stronger presence within the community.
- ✓ To engage current and prospective employees and partnerships; inspire them, build trust and position CPUC as a great place to work or as a great partner.
- ✓ Fair Hydro Plan – Under the protection, the OEB sets a maximum monthly base distribution charge. On June 22, 2017 the OEB set the maximum monthly base charge at $36.43 and updated it to $36.86 in July of 2018.

5.5 CPUC Threats

In addition to its many regulatory responsibilities, the business of distributing electricity has several basic risk considerations that must be managed successfully to ensure business continuity.

The following areas of exposure were identified and evaluated as part of the CPUC risk profile:

- ✓ **Reliability**

  Although the utility's reliability metrics are well above the OEB's standards(is this true for us?), customers have very high service expectations, and any system interruptions should be handled quickly and professionally. Reputational risks can occur when incidents and outages are not perceived to be addressed in a quick and efficient manner. Customers accept the occasional power outage, but confidence is eroded when they cannot get access to timely information on the nature of the incident and an estimate of restoration times.

  If an unplanned outage occurs within CPUC's service area, CPUC will immediately contact its operations personnel or contractors and escalate the issues. If an issue occurs where the utility suspects that it is outside of its territory, the utility will contact Hydro One ill to let them know that the CPUC service area is out. For planned outages, the customers affected will be contacted at least 48 hours before by phone, by either mail or newspapers

  For all outages, CPUC personnel updates its social medias and attempts to give as much details as possible to its customers regarding the location, area affected and timing of the restoration of power.

- ✓ **Succession Planning**

  Within the next 2 years, CPUC may see the leave of its current General Manager due to his eligibility to retire. The utility recognizes that finding a candidate with industry specific competencies in smaller rural LDCs is tough. As such, over the past year, CPUC has put substantive effort into its succession planning which involves training its employees on every aspect of the utility. Documenting processes have also become a priority.

- ✓ **Remoteness and lack of growth**

  While remote utilities present many opportunities, utilities such as CPUC also face challenges which they must navigate to operate successfully. Management faces particular challenges in the area of market size, labour availability, access to urban centres, infrastructure gaps, and larger time demands

6. Personnel Plan

CPUC is facing the same challenges the electricity industry is about its aging demographics and infrastructure. Matching the resource capability with the work demands in the electricity sector requires planning which is what CPUC is currently executing. Numerous contributing factors are impacting workforce planning, including a shortage of proficiently skilled labour, and increased work demands, therefore, CPUC has opted to invest instead in its current staff members on the various aspects of running a utility.

CPUC currently employs one General Manager, a Manager of Finance and a Billing and Customer Service clerk. CPUC also currently employs two Power Line Maintainer . CPUC does not plan to hire additional staff in 2018 and 2019. CPUC notes that employee pay raises reflect the rate of inflation, CPUC must also rely on third party contractors and consultants, mainly for the maintenance of the distribution system and assistance with meeting its regulatory requirements.

In the Spring of 2018, the utility hired a consulting firm to conduct a job title & description analysis to better understand the requirements of the business as well as prepare for succession planning. CPUC continues to reviews its business and operational goals against; its workforce needs, its financial strength and the impact on its customers. CPUC recognizes the importance and value of maintaining a highly skilled and engaged workforce, where all employees are customer focused and proud to work for the utility.

Table 10 - FTE Employment

Trades & Technical Positions	Current #'s	Minimum #'s	2018 Projection	2019 Projections
General Manager (formally Manager)	1	1	1	1
Director of Finance (formally Treasurer)	1	1	1	1
CSR/Billing Clerk (formally Secretary)	1	1	1	1
Powerline Maintainer	2	2	2	2

7. Financial Results

CPUC's financial performance has been unstable since its last Cost of Service application in 2012. Over the past six years, CPUC has seen its income fluctuate from a deficiency of $151,846 in 2012 Actual to a sufficiency of 53,384 in 2015. The biggest deficiency is predicted to be in 2018. This as a result of the change in the utility's corporate structure. On January 1, 2018, the utility went from a "virtual utility" to a "traditional utility.

Table 11 – Reported Income

	Income/(Loss)	Sufficiency/(Deficiency)
2012	$(86,209)	$(151,846)
2013	$150,769	$57,599
2014	$148,485	$51,097
2015	$35,866	$53,384
2016	$24,037	$(63,326)

By the end of 2018, CPUC will be under-earning due mainly to the fact that the utility was being subsidized by an affiliate. The affiliate was reporting a loss and as such closed its doors on December 31, 2017.

Another reason for the deficiency is that the utility's depreciation expense increased as a result of the purchase of a new boom truck. Details regarding the vehicle are presented in the utility's Distribution System Plan, and details relating to one-time costs are explained in the utility's Cost of the Service application, specifically throughout Exhibit 4. The rate on return for 2019 is expected to be 9.00% as prescribed by the OEB.

Table 12 – Financial Ratios from Scorecards

Financial Ratios

	Liquidity: Current Ratio (Current Assets/Current Liabilities)	Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	Profitability (Approved ROE)	Regulatory Return on Equity (Achieved ROE)
2012	1.69	0.00	9.12	-17.50%
2013	1.75	0.00	9.12	19.84

2014	2.04	0.00	9.12	16.88
2015	2.05	0.00	9.12	0.40
2016	2.03	0.00	9.12	3.82

7.1 Important Assumptions

Load forecasting affects all aspects of the utility's future including supply capacity of the distribution system and revenue requirements. The load forecast also the potential to be significantly impacted by Conservation and Demand Management targets. Each LDC has a target to reduce its annual energy supplied (kWh). CPUC's target is 1,050,000 kWh in energy reduction 2015-2020.

Since expenses and revenues are often closely tied to the utility's customer count and load, it is important to go over the utility's historical and projected load before discussing financial results. CPUC's is not projecting growth in any of its classes with the exception of a small yet steady increase in the GS>50 class. CPUC's load and customer projections support the Economic Outlook Summary which indicates that population growth is expected to remain unchanged in 2018 and 2019. The second important assumption is the stability of operating costs going forward. Table 13 below shows the utility historical operating costs and projected costs for 2019.

Table 13 - Load and Customer Forecast Table

	Year	2012	2013	2014	2015	2016	2017	2018	2019 CDM Adjusted
Residential	Cust/Conn	1,108	1,062	1,063	1,059	1,059	1,054	1,043	1,033
	kWh	13,667,868	15,071,570	15,225,943	13,727,288	12,612,066	12,775,802	14,078,629	13,831,681
	kW								
General Service < 50 kW	Cust/Conn	162	153	152	152	157	152	150	148
	kWh	5,015,356	5,337,892	5,251,375	4,907,587	4,617,295	4,702,580	5,010,785	4,880,502
	kW								
General Service > 50 to 4999 kW	Cust/Conn	11	11	10	11	12	15	15	15
	kWh	7,148,661	7,164,613	7,157,299	6,867,603	7,048,334	6,797,046	7,234,473	7,147,174
	kW	18,736	18,431	20,149	18,062	18,740	17,522	19,002	18,883
Unmetered Scattered Load	Cust/Conn	4	4	4	4	4	4	4	4
	kWh	2,892	2,892	2,892	2,892	2,892	2,892	5,232	5,232
	kW	-	-	-	-	-	-	-	-
Sentinel	Cust/Conn	23	23	23	23	23	23	23	23
	kWh	25,594	26,244	26,857	23,735	19,993	20,629	24,760	24,760
	kW	60	65	75	63	60	62	65	65
Street Lighting	Cust/Conn	328	328	328	328	328	328	328	328

	kWh	287,471	274,269	274,528	274,259	274,259	274,259	283,967	283,967
	kW	777	768	768	768	768	768	774	774
Total	**Cust/Conn**	**1,636**	**1,581**	**1,579**	**1,577**	**1,582**	**1,576**	**1,564**	**1,552**
	kWh	**26,147,842**	**27,877,480**	**27,938,894**	**25,803,364**	**24,574,839**	**24,573,208**	**26,637,846**	**26,173,316**
	kW	**19,573**	**19,264**	**20,992**	**18,893**	**19,568**	**18,352**	**19,841**	**19,722**

CPUC's 2019 Test Year operating costs are projected to be $821,163 which represents an increase of $176,823 from its 2012 Cost of Service or 28%. These operating costs are necessary to comply with the Distribution System Code, environmental requirements, and government direction. The bulk of the increase in OM&A in 2018-2019 is attributable to the change in organisational structure where it became evident that the utility had been subsidized by the affiliate for some time. In an effort to plan for succession, the utility has put in place 2 management positions instead of a single manager. The increase in Administrative Costs is for the most part related to an increase in Regulatory Costs necessary to comply with new policies and requirements.

Table 14 - Operation Costs Table

	Board Approved	2012	2013	2014	2015	2016	2017	2018	2019
Operations	$205,440	$289,711	$220,412	$223,211	$208,239	$236,332	$237,909	$247,400	$242,760
Maintenance	$0	$0	$0	$0	$0	$0	$0	$0	$1,610
SubTotal	**$205,440**	**$289,711**	**$220,412**	**$223,211**	**$208,239**	**$236,332**	**$237,909**	**$247,400**	**$244,370**
%Change (year over year)		41.0%	-23.9%	1.3%	-6.7%	13.5%	0.7%	4.7%	-1.2%
%Change (Test Year vs Last Rebasing Year - Actual)									-15.7%
Billing and Collecting	$84,200	$95,585	$115,086	$135,609	$129,895	$121,157	$121,220	$135,000	$133,730
Community Relations	$600	$115	$415	$415	$115	$415	$415	$0	$0
Administrative and General+LEAP	$354,100	$285,195	$302,558	$385,438	$392,316	$386,133	$357,042	$427,004	$443,063
SubTotal	**$438,900**	**$380,896**	**$418,059**	**$521,463**	**$522,325**	**$507,705**	**$478,677**	**$562,004**	**$576,793**
%Change (year over year)		-13.2%	9.8%	24.7%	0.2%	-2.8%	-5.7%	10.7%	2.6%
%Change (Test Year vs Last Rebasing Year - Actual)									51.4%
Total	**$644,340**	**$670,607**	**$638,471**	**$744,673**	**$730,565**	**$744,037**	**$716,586**	**$809,404**	**$821,163**
%Change (year over year)		4.1%	-4.8%	16.6%	-1.9%	1.8%	-3.7%	13.0%	1.5%

7.2 Actual Return vs. Allowed Return

✓ **Liquidity: Current Ratio (Current Assets/Current Liabilities)**

CPUC's current ratio increased slightly from 1.12 in 2011 to 1.18 in 2012(I don't know 2011 and 2012's) and declined to 1.75, 2.04 and 2.05 in 2013, 2014 and 2015 respectively. CPUC's ratios are indicator of good financial health. CPUC expects its liquidity to remain stable if not improve going forward.

✓ **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**

By Board policy, the utility used a deemed capital structure of 60% debt, 40% equity when establishing rates. The utility does not currently carry any debt however, with the distribution station nearing the end of its useful life, the CPUC may seek out debt to finance a new station in the near future.

✓ **Profitability: Regulatory Return on Equity – Deemed (included in current rates) and Achieved**

CPUC's current distribution rates were rebased and approved by the OEB in 2012 and included an expected (deemed) regulatory return on equity of 9.12%. The OEB allows a distributor to earn within +/- 3% of the expected return on equity. Unfortunately, CPUC has had difficulties keeping its achieved ROE within the Board Approved ROE of 9.12. The main reason being that with total costs being so low and one-time costs being sometimes high, it is difficult for a small utility to keep within the range. That said, CPUC commits to using financial tools and checks to ensure the utility maintains its profitability at the approved level going forward.

Table 15 - Return on Equity Table

	2012	2013	2014	2015	2016	2017
Return on Equity	-17.50%	19.84%	16.88%	0.40%	-3.82%	-1.99

7.3 Profit and Loss

Outlined below, and in the following table, are some of the essential components of the projected profit and loss for CPUC:

- ✓ Operating Revenues for 2018 and 2019 are forecast to be $877,471 and $1,029,059.
- ✓ Cost and Expenses for 2018 and 2019 are predicted to be $971.486 and $930,013.
- ✓ Taxes for 2018 and 2019 are predicted to be $0 and $0 respectively.
- ✓ The net profit/loss for 2018 and 2019 are forecast to be $-98,035 and $59,218, respectively.

Table 16 - Profit and Loss Table

	Board Approved	Actual	Actual	Actual	Actual	Actual	Actual	Projected	Projected
WCA	**2012**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Cost of Power	2,516,183	2,449,277	2,841,690	3,507,606	3,115,911	3,263,340	2,667,417	2,600,626	2,692,686
WCA Rate	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	7.50%
	Board Approved	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Projected**	**Projected**
Derivation of Utility Income	**2012**	**2012**	**2013**	**2014**	**2015**	**2016**	**2016**	**2017**	**2018**
Operating Revenues									
Distribution Revenues	798,919	691,158	865,499	948,351	830,055	784,831	769,956	783,561	1,004,820
Other Revenue	41,735	36,786	10,058	30,361	-1,687	47,433	36,942	93,910	50,729
Total Operating Revenues	**840,654**	**727,944**	**875,558**	**978,712**	**828,367**	**832,264**	**806,898**	**877,471**	**1,055,548**
OM&A Expenses	644,340	670,607	638,471	744,673	730,565	744,037	716,586	809,404	821,163
Depreciation & Amortization	75,576	113,903	72,025	72,466	50,827	52,874	49,114	154,279	120,706
Property and Taxes	13,150	0	0	0	0	0	0	8,100	8,262
Total Costs & Expenses	**733,066**	**784,510**	**710,496**	**817,139**	**781,392**	**796,911**	**765,700**	**971,783**	**950,131**
Deemed Interest Expenses	38,606	19,759	7,170	6,037	4,490	2,425	4,020	4,020	42,390
Total Expenses	**771,672**	**804,269**	**717,666**	**823,176**	**785,882**	**799,336**	**769,719**	**975,803**	**992,521**
Utility Income before Income Taxes / PILs	**68,982**	**-76,324**	**157,892**	**155,535**	**42,485**	**32,928**	**37,178**	-98,332	63,028
PILs / Income Taxes	13,814	9,885	7,123	7,050	6,619	8,891	12,042	0	0
Adjustments for FS purposes (donations/taxes)			0				0		
Utility Income	**55,168**	**-86,209**	**150,769**	**148,485**	**35,866**	**24,037**	**25,136**	**-98,332**	**63,028**
		86,209	**-156,931**	**-148,485**	**-35,866**	**-24,037**	**-25,136**		

7.4 Rate Base and Revenue Deficiency

As shown in the following table, CPUC's revenue deficiency has steadily grown since 2016 indicating that it is time for the utility to re-establish its rates based on its costs. The revenue sufficiency growing over time, is largely due to the increased costs due to the change in corporate structure as well as a change in the management.

The utility showed a revenue sufficiency for 2013-2014-2015 but since then has reported a revenue deficiency of $63K in 2016 and $60K in 2017. The utility expects the revenue deficiency in 2018 and a 0 in 2019 as new rates are set to eliminate any deficiency.

Table 17 - Table of Rate Base and Revenue Deficiency

	Board Approved	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Projected**	**Projected**
	2012	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Utility Income	**55,168**	**86,209**	**-156,931**	**-148,485**	**-35,866**	**-24,037**	**-25,136**	-98,332	63,028
Gross Fixed Assets (year end)	2,554,525	2,562,037	2,650,263	2,694,186	2,795,361	2,831,645	2,861,812	3,884,684	3,965,351
			88,227	43,923	101,175	36,284	30,167	1,028,972	80,667
Accum Depreciation	-1,517,843	-1,478,772	-1,550,797	-1,623,263	-1,674,089	-1,726,964	-1,776,077	-2,378,056	-2,498,762
Net Fixed Assets	1,036,682	1,092,839	1,099,466	1,070,923	1,037,247	1,104,681	1,085,734	1,506,628	1,466,589
Average Net Fixed Assets	1,036,682	909,192	1,096,153	1,085,195	1,054,085	1,070,964	1,095,208	1,296,181	1,486,609
Utility Rate Base	1,512,283	1,377,175	1,618,177	1,723,037	1,631,057	1,672,071	1,602,808	1,808,901	1,750,767
Deemed Equity Portion of Rate Base	604,913	550,870	647,271	689,215	652,423	668,828	641,123	723,560	700,307
Income/(Equity Portion of Rate Base)	9.12%	6.26%	-9.70%	-8.62%	-2.20%	-1.44%	-1.57%	-5.44%	3.60%
Indicated Rate of Return	6.20%	-4.83%	9.76%	9.17%	9.47%	2.41%	2.49%	-5.21%	6.02%
Approved Rate of Return	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.02%
Sufficiency / (Deficiency) in Return	0.00%	(11.03%)	3.56%	2.97%	3.27%	(3.79%)	(3.71%)	(11.41%)	0.00%
Equity	*40%*	*40%*	*40%*	*40%*	*40%*	*40%*	*40%*	40%	40%
Short Term Debt	*4%*	*4%*	*4%*	*4%*	*4%*	*4%*	*4%*	4%	4%
Long Term Debt	*56%*	*56%*	*56%*	*56%*	*56%*	*56%*	*56%*	56%	56%
Equity Return	*9.12%*	*9.12%*	*9.12%*	*9.12%*	*9.12%*	*9.12%*	*9.12%*	9.12%	9.00%
Short Debt Return	*2.08%*	*2.08%*	*2.08%*	*2.08%*	*2.08%*	*2.08%*	*2.08%*	2.08%	2.29%
Long Debt Return	*4.41%*	*4.41%*	*4.41%*	*4.41%*	*4.41%*	*4.41%*	*4.41%*	4.41%	4.16%
Tax Rate	*15.50%*	*15.50%*	*15.50%*	*15.50%*	*15.50%*	*15.50%*	*15.50%*	15.50%	15.50%
Net Revenue Sufficiency / (Deficiency)	**0**	**-151,846**	**57,599**	**51,097**	**53,384**	**-63,326**	**-59,501**	-206,479	0
		deficiency	*Sufficiency*	*Sufficiency*	*Sufficiency*	*Deficiency*	*Deficiency*	*Deficiency*	

1.3 ADMINISTRATIVE

1.3.1 SUMMARY OF APPLICATION

Application contact information is as follows:

Applicants Name:	Chapleau Public Utilities Corporation
Applicants Address:	110 Lorne Street South
	P.O. Box 670
	Chapleau, ON, P0M 1K0
	Phone: 705-864-0111
	Fax: 705-864-1962

1.3.1 CONTACT INFORMATION[4]

Application contact information is as follows:

Applicants Name:	Chapleau Public Utilities Corporation
Applicants Address:	110 Lorne Street South
	P.O. Box 670
	Chapleau, ON, P0M 1K0
	Phone: 705-864-0111
	Fax: 705-864-1962
CPUC's Contact Info.	Alan Morin
	General Manager

[4] MFR - Primary contact information (name, address, phone, fax, email)

	amorin.puc@chapleau.ca
	Phone: 705-864-0111
CPUCs Counsel:	Michael Buonaguro[5]
	Email: Michael Buonaguro <mrb@mrb-law.com>
	Phone: 416-767-1666
Community Based Venue[6]	The Chapleau Recreational Sports Complex is comprised of one ice skating, skating on outdoor rink. and hockey arena, a four-sheet curling surface and lounge, a Community Hall with capacity for 275 occupants, and one lighted softball diamond. (For rental information, contact the Township of Chapleau's Recreation Centre at 705-864-0154.)

[5] MFR - Identification of legal (or other) representation
[6] MFR – List of one or more accessible community based venues.

1.3.2 CONFIRMATION OF INTERNET ADDRESS[7]

The application is posted on CPUC's website address at http://www.chapleau.ca/en/townshipservices/publicutilities.asp, and a message to that effect was posed on the utility's website, Facebook page and Twitter site.

[7] MFR - Applicant's internet address for viewing of application and any social media accounts used by the applicant to communicate with customers

1.3.3 STATEMENT OF PUBLICATION[8]

Upon receiving the Letter of Direction and the Notice of Application and Hearing from the Board, the OEB will arrange to have the Notice of Application and Hearing for this proceeding published in the following local community not-paid-for newspaper which has the highest circulation in its service area.

The Chapleau Express
14 Richard Street
Chapleau, ON   P0M 1K0
Phone # 705-864-2579

Once the Notice of Application and Hearing has been published in the above listed newspapers, CPUC will file an Affidavit of Publication.

[8] MFR - Statement identifying where notice should be published and why.

1.3.4 LEGAL APPLICATION

In the matter of; the Ontario Energy Board Act, 1998; S.O. 1998, c.15, Schedule B, as amended; and in the matter of; an Application by Chapleau Public Utilities Corporation. for an Order or Orders approving or fixing just and reasonable distribution rates effective May 1, 2019.[9]

CPUC is a fully licensed distributor of electricity under distribution license ED-2002-0528 issued by the Ontario Energy Board (the "OEB" or the "Board") under the Ontario Energy Board Act, 1998 (the "Act").

CPUC hereby applies to the Board pursuant to section 78 of the Act for an Order or Orders approving or fixing just and reasonable distribution rates effective May 1, 2019.[10]

This Application is made in accordance with the Board's Chapter 2 of the Board's Filing Requirements for Transmission and Distribution Applications dated July 20, 2017 and Chapter 2 of the Board's Filing Requirements for Transmission and Distribution Applications dated July 12, 2018 where ever possible. CPUC accordingly applies to the Board for the following Order or Orders:

1) Approval to charge distribution rates effective May 1, 2019 to recover a base revenue requirement of $1,004,820 which includes a revenue deficiency of $221,259 using the Service Revenue Requirement as detailed in Exhibit 6. The schedule of proposed rates is set out in Exhibit 8.
    2) Approval of the Distribution System Plan as outlined in Exhibit 2 Section 2.5.2.
    3) Approval to adjust the Retail Transmission Rates – Network and Connection as detailed in Exhibit 8.

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[9] MFR - Statement identifying all deviations from Filing Requirements; identify concerns with models or changes to models
[10] MFR - Requested effective date

4) Approval of the proposed loss factors as detailed in Exhibit 8.
5) Approval to continue to charge Wholesale Market and Rural Rate Protection Charges approved in the Board Decision and Order in the matter of CPUC 2017 Interim Distribution Rates (EB-2017-0337).
6) 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.
7) Approval to dispose of balances in the LRAM variance account as presented in Exhibit 9.
8) Such other approvals that CPUC may request and that the OEB accepts.

A full list of approvals is presented in PDF format at Appendix G of this Exhibit.

Certification of accuracy and completeness of application:

CPUC hereby certifies that the application has been reviewed and approved by the General Manager, Finance Manager and Board of Directors. Board of Directors, who have been kept informed throughout the preparation of the budget and application, have passed a resolution approving the application. CPUC and confirms that the information and evidence presented herein is accurate to the best of CPUC's knowledge. [11]

Confidential Information:

CPUC confirms that the application does not include any confidential information.[12]

[11] MFR - Certification by a senior officer that the evidence filed is accurate, consistent and complete
[12] MFR - Confidential Information - Practice Direction has been followed

Align rate year with fiscal year:

CPUC is not proposing to align its rate year with its fiscal year in this proceeding. Therefore, no further adjustments are required in that respect.[13] CPUC notes that it has no special conditions in its license.

[13] MFR - Aligning rate year with fiscal year - request for proposed alignment
MFR - List of approvals requested (and relevant section of legislation), including accounting orders - a PDF copy of Appendix 2-A should be provided in this section

1.3.5 BILL IMPACTS[14]

The 2019 distribution rates proposed by CPUC will result in overall bill impacts for residential customers using 750kWh per month of 4.04$ (TOU) and GS<50 using 2000kWh per month of -9.12$% (TOU). GS 50-4999kW are expected to increase by 5.39%. Unmetered Scattered Load are projected to decrease by 11.85% and Sentinel and Street Lighting will go up by 24.77% and 12.54% respectively. Table 1 below shows a summary of all components of the bill impacts.

A full list of the bill impacts applicable to all customer classes is found in Exhibit 8, Section 8.1.15 of this application. CPUC confirms that since it's is applying for a readjustment of rates for all classes, that all customer groups will be affected by the proposed change.[15]

[14] MFR - Bill impacts - distribution only impacts for 750 kWh residential and 2000 kWh GS<50 (sub-total A of Tariff Schedule and Bill Impact Spreadsheet Model) to be used for notice
[15] MFR - Statement identifying customers materially affected by the application including any change to any rate or charge and specific statement of what individual customer or customer groups would be affected by the proposed change

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Table 1- Total Bill Impacts

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	Sub-Total						Total	
		A		B		C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	$1.96	5.67%	$3.61	9.34%	$3.69	8.15%	$4.70	4.04%
GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION - RPP	kwh	$17.40	24.51%	$22.40	27.67%	$22.61	23.33%	$25.95	9.12%
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION - Non-RPP (Retailer)	kw	$180.49	29.60%	$276.35	43.47%	$282.03	28.48%	$368.52	5.39%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kwh	-$4.13	-15.28%	-$4.01	-14.68%	-$4.00	-14.40%	-$4.45	-11.85%
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	kw	$10.08	42.53%	$10.66	43.13%	$10.70	39.53%	$12.32	24.77%
STREET LIGHTING SERVICE CLASSIFICATION - RPP	kw	$373.94	28.24%	$421.13	31.47%	$423.62	28.48%	$505.81	12.54%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kwh	$6.79	22.85%	$7.68	23.45%	$7.72	21.26%	$9.21	9.83%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kwh	$1.96	5.67%	$3.61	9.10%	$3.69	7.97%	$5.06	3.38%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	$6.79	22.85%	$7.68	23.87%	$7.72	21.60%	$8.56	11.44%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kwh	$0.07	0.19%	$2.71	6.11%	$2.84	5.16%	$4.63	2.12%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kwh	$0.07	0.19%	$2.71	6.11%	$2.84	5.16%	$4.63	2.12%
GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION - Non-RPP (Retailer)	kwh	$17.40	24.51%	$22.40	26.74%	$22.61	22.67%	$27.92	7.49%
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION - Non-RPP (Retailer)	kw	$180.49	29.60%	$276.35	43.47%	$282.03	28.48%	$368.52	5.39%

Subtotal A: represents the distributor's fixed and variable charges
Subtotal B: represents Subtotal A plus low voltage charges and deferral and variance rate riders
Subtotal C: represents Subtotal B network connection and transmission charge
Total Bill impacts includes Subtotal C and administrative charges, pass-through charges, commodity and taxes.

1.3.6 STATEMENT AS TO THE FORM OF HEARING REQUESTED[16]

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

CPUC requests that pursuant to Section 34.01 of the Board's Rules of Practice and Procedure, this proceeding be conducted by way of written hearing in an effort to minimize costs but understands that if certain issues remain unsettled post settlement, the utility may be asked to participate in an oral hearing.

1.3.7 PROPOSED ISSUES LIST[17]

In establishing the overall appropriateness of the proposed rates, CPUC anticipates that the following issues will be addressed by the Board and interveners.

Planning

Capital

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

- ✓ customer feedback and preferences
- ✓ productivity
- ✓ benchmarking of costs
- ✓ reliability and service quality
- ✓ impact on distribution rates
- ✓ trade-offs with OM&A spending
- ✓ government-mandated obligations, and
- ✓ the objectives of the Applicant and its customers.

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[16] MFR - Form of hearing requested and why
[17] MFR - List of approvals requested (and relevant section of legislation), including accounting orders - a PDF copy of Appendix 2-A should be provided in this section

OM&A

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

- ✓ customer feedback and preferences
- ✓ productivity
- ✓ benchmarking of costs
- ✓ reliability and service quality
- ✓ impact on distribution rates
- ✓ trade-offs with capital spending
- ✓ government-mandated obligations, and
- ✓ the objectives of the Applicant and its customers.

Revenue Requirement

- ✓ Are all elements of the Revenue Requirement reasonable, and have they been appropriately determined in accordance with OEB policies and practices?
- ✓ Has the Revenue Requirement been accurately determined based on these elements?

Load Forecast, Cost Allocation, and Rate Design

- ✓ Are the proposed load and customer forecast, loss factors, CDM adjustments and resulting billing determinants appropriate, and, to the extent applicable, are they an appropriate reflection of the number and energy and demand requirements of the applicant's customers?
- ✓ Are the proposed cost allocation methodology, allocations, and revenue-to-cost ratios appropriate?
- ✓ Are the applicant's proposals, including the proposed fixed/variable splits, for rate design appropriate?

Are the proposed Retail Transmission Service Rates and Low Voltage Service Rates appropriate?

Accounting

- ✓ Have all impacts of any changes in accounting standards, policies, estimates and adjustments been properly identified and recorded, and is the rate-making treatment of each of these impacts appropriate?
- ✓ Are the applicant's proposals for deferral and variance accounts, including the balances in the existing accounts and their disposition, and the continuation of existing accounts appropriate?

1.3.8 STATEMENT OF DEVIATION OF FILING REQUIREMENTS[18]

Except where specifically identified in the Application, CPUC followed Chapter 2 of the OEB's "Filing Requirements for Electricity Transmission and Distribution Applications," dated July 20, 2017 (the "Filing Requirements") as well as Chapter 2 of the OEB's "Filing Requirements for Electricity Transmission and Distribution Applications," dated July 12, 2018 in order to prepare this application. The Excel version of the complete 2018/2019 (where applicable) Cost of Service checklist is being filed in conjunction with this application.

1.3.9 CHANGES IN METHODOLOGIES[19]

The projections for the 2019 Test Year were prepared in accordance with CPUC's budget process as described in Section 1.5 of this Exhibit. All processes are in compliance with policies, directives and rules and guidelines from the Ontario Energy Board and other regulators.

1.3.10 BOARD DIRECTIVE FROM PREVIOUS DECISIONS

At the date of this submission, CPUC is not aware of any Board Directives from any previous Board Decisions and/or Orders that require addressing in this Application. [20]

1.3.11 CONDITIONS OF SERVICE

[18] MFR - Statement identifying all deviations from Filing Requirements; identify concerns with models or changes to models
[19] MFR - Statement identifying and describing any changes to methodologies used vs previous applications
[20] MFR - Identification of OEB directions from any previous OEB Decisions and/or Orders. The applicant must clearly indicate how these are being addressed in the current application (e.g., filing of a study as directed in a previous decision)

CPUC's conditions of service are updated on a regular basis and were last updated in October of 2017. The utility's most recent Conditions of Service are accessible on the utility's website at http://www.chapleau.ca/en/townshipservices/publicutilities.asp. CPUC confirms that that the conditions of service do not purport to establish any charges that are not approved as part of the posted tariff sheet Conditions of Service but that the tariff sheet is posted on the utility's website.[21]

[21] MFR - Reference to Conditions of Service - LDC does not need to file Conditions of Service, but must provide reference to website and confirm version is current; identify if there are changes to Conditions of Service (a) since last CoS application or (b) as a result of the current application. Confirmation that there are no rates and charges linked in the Conditions of Service that are not in the distributor's Tariff of Rates and Charges must be provided

1.3.12 ACCOUNTING STANDARDS FOR REGULATORY AND FINANCIAL REPORTING

Changes in Tax Status:[22]

CPUC is a corporation incorporated pursuant to the Ontario Business Corporations Act and has not had a change in tax status since its last Cost of Service Application.

Existing/Proposed Accounting Orders[23]

The Accounting Standard Board ("AcSB") adopted MIFRS for qualifying rate-regulated entities on January 1, 2015. In accordance with a Board's letter of July 17, 2013, electricity distributors electing to remain on CGAAP were required to implement regulatory accounting changes for depreciation expenses and capitalization policies by January 1, 2013.

CPUC confirms it implemented the regulatory accounting changes for depreciation in 2013. The herein 2019 Cost of Service Application is being filed based on the MIFRS accounting basis.

Accounting Standard used in Application

CPUC confirms that it made the required changes to its depreciation rates in 2013. CPUC adopted MIFRS in January of 2015. The details with respect to these changes are provided in Exhibit 2 and Exhibit 4. Details with respect to the new useful lives applied to capital assets and the resulting impact on depreciation are shown in Exhibit 4.

In accordance with the Filing Requirements, CPUC has provided information for the historical years using modified CGAAP presentation for 2013 and MIFRS for 2015. CPUC has provided the 2018 Bridge Year based on MIFRS and the 2019 Test Year is presented on an MIFRS basis.[24]

Employee Pension and Benefits.

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[22] Any change in tax status
[23] Accounting Standards used for financial statements and when adopted
[24] MFR - State accounting standard(s) used in historical, bridge and test years. Provide a summary of changes to its accounting policies made since the applicant's last cost of service filing. Identify all material changes or confirm no material changes in the adoption of IFRS. Appendix 2-Y

CPUC does have any Employee Future Benefits ("EFB") and as such, has recorded costs in OM&A in USoA 5645. The topic is discussed further in Exhibit 4.

Compliance with the Uniform System of Accounts[25]

CPUC has followed the accounting principles and main categories of accounts as stated in the OEB's Accounting Procedures Handbook (the "APH") and the Uniform System of Accounts ("USoA") in the preparation of this Application.

The useful lives proposed by CPUC in this Application are consistent with the typical useful lives in the Kinectrics Report commissioned by the OEB dated July 8, 2010. CPUC's accounting methodology change in this regard took effect in 2013 pursuant to Board policy.

CPUC has never capitalized administration and other general overhead costs, which is, in any event, no longer permitted under MIFRS.

CPUC has also adopted the various account changes prescribed by the Board in relation to the USoA (Article 210 – Chart of Accounts and Account 220 – Account Descriptions). Consistent with recent applications to the Board, CPUC no longer includes PST in its OM&A cost estimates. Regulatory costs for 2019 have been normalized by allocating one fifth of those costs to the 2019 Test Year.

CPUC is not proposing other changes in methodology. The OEB Appendix 2-Y below shows that the 2019 Revenue Requirement under MIFRS is identical to the scenario under NEWCGAAP.

[25] Existing accounting orders and departures from the accounting orders and USoA

Table 2 – OEB Appendix 2-Y Summary of Impacts to Revenue Requirement from Transition to MIFRS

Revenue Requirement Component	2019 **MIFRS**	2019 **CCGAAP**	Difference	Reasons why the revenue requirement component is different under MIFRS
Closing NBV 2018	1,506,628	1,339,817	166,811	Change in useful lives
Closing NBV 2019	1,466,589	1,299,778	166,811	Change in useful lives
Average NBV	1,486,609	1,319,798	166,811	Change in useful lives
Working Capital	264,158	264,158	0	No change
Rate Base	1,750,767	1,583,956	166,811	Change in useful lives
Return on Rate Base	105417.2	95737	9,680	Change in useful lives
OM&A	821163	821163	0	No change
Depreciation	120706	120706	0	No change
Property taxes	8262	8262	0	
PILs or Income Taxes	0	0	0	No change
Less: Revenue Offsets	-50729	-50729	0	No change
Total Base Revenue Requirement	1,004,820	995,139	9,680	No change

Monthly Billing[26]

CPUC confirms that all its customers are billed on a monthly basis as of 2013.

1.3.13 ACCOUNTING TREATMENT OF NON-UTILITY RELATED BUSINESS

CPUC is engaged in the delivery of the Independent Electricity System Operator's ("IESO") (previously before amalgamation it was the Ontario Power Authority) conservation and demand management programs. The accounting for these activities is segregated from CPUC's rate regulated activities in accordance with the Board's Accounting Procedures Handbook for Electricity Distributors.

In addition to the sale of electricity to its customers, CPUC from time to time engages in non-utility related activities such as chimney cleans, cutting trees, Hydro One emergencies, street lighting and other miscellaneous jobs. CPUC confirms that accounting treatment of any non-utility business was segregated activities from rate regulated activities for that time period.[27]

1.3.14 OPERATING ENVIRONMENT

The utility's operating environment and service area has not changed since its last Cost of Service in 2012. A description of the operating environment and ownership description is presented in section 1.5 of the Business Plan and duplicated below for ease of reference.

> *CPUC is licensed by the Board to distribute electricity to the inhabitants of the Town of Chapleau.*
>
> *The sole Shareholder of The Applicant is the Town of Chapleau. The population of the Municipality of Chapleau is approximately 2,000. The distribution service area within the Town of Chapleau is located in central Northeastern Ontario, in the heart of the Canadian Shield. Chapleau is geographically isolated; the nearest cities are Sault Ste. Marie, Timmins, and Sudbury, but all are more than*

[26] MFR - Statement confirming that the distributor will have implemented monthly billing for all customers by December 31, 2016
[27] MFR - Confirmation that accounting treatment of any non-utility business has segregated activities from rate regulated activities

a two-hour drive away. Highway 129 links the town with Highway 101, running east to Timmins and west to Wawa. Highway 129 also runs south, connecting with the Trans-Canada Highway, Highway 17 at Thessalon, 227 km from Chapleau.

1.3.15 CORPORATE ORGANIZATION

CPUC employs a workforce of 5 people. [28]

A General Manager

- Leads and supervises the business and affairs of the Corporation and the performance of the Utility by directing and coordinating all activities in accordance with applicable laws and regulations, vision, mission, values and strategic plan priorities.

A Manager of Finance

- Responsible for the accounting, financial reporting and overall financial health of the organization including annual budget, payroll, audits, regulatory affairs, delinquent accounts and accounts receivables/payables.

A Billing and Customer Service Clerk

- Responsible for the administrative processes of the organizations including mail preparation / distribution, billing and payment processing, customer service by phone and in person, prepare meeting minutes and do bank deposits.

Two Powerline Maintainers

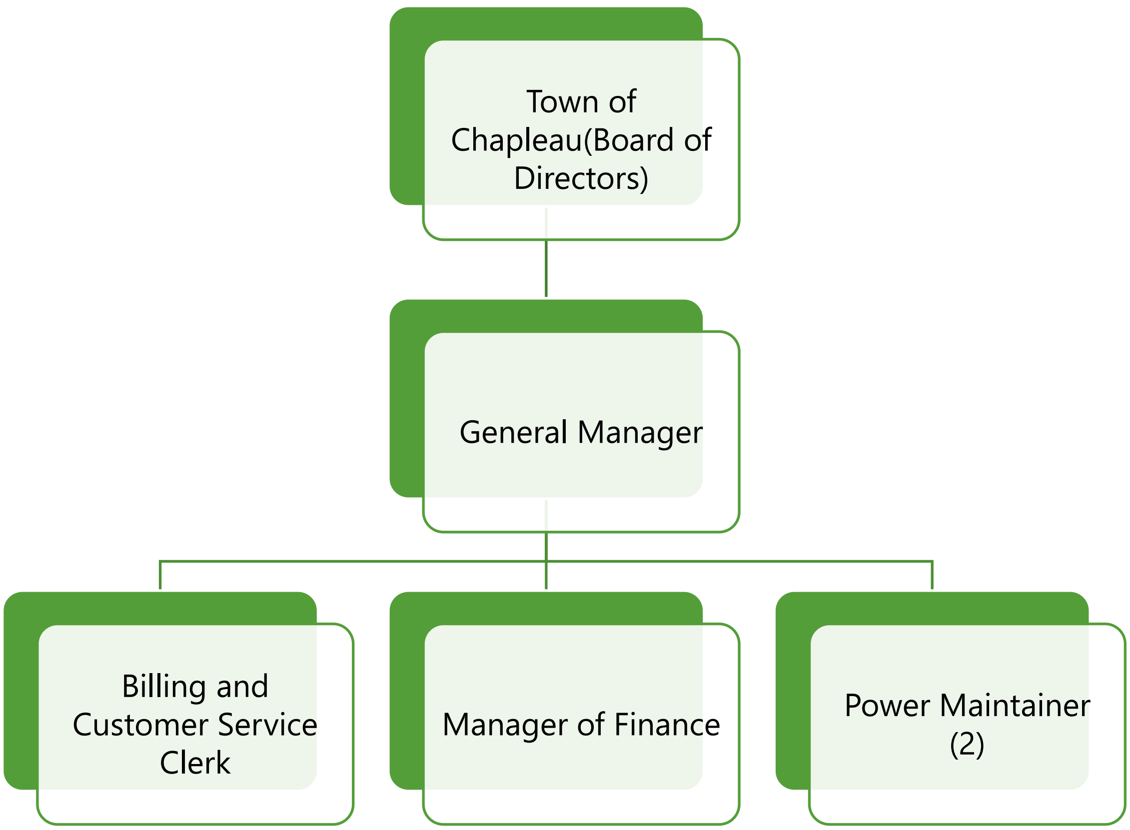
- Responsible for the construction and maintenance of overhead and underground infrastructure, maintenance and upgrades to substations, meter changes / installations and infrastructure locates.

[28] MFR - Description of the corporate and utility organizational structure, showing the main units and executive and senior management positions within the utility. Include a corporate entities relationship chart, showing the extent to which the parent company is represented on the utility company's Board of Directors and a description of the reporting relationships between utility and parent company management. Also include any planned changes in corporate or operational structure, including any changes in legal organization and control

The above relationships are shown in the Utility Organization Chart at the next page.

The General Manager is responsible for the following activities. A more detailed list of activities is presented at Exhbit 4.

Table 3 - Organizational and Corporate Structure Chart (at time of filing)



Reporting Relationship Between CPUC and the Town of Chapleau
The Town of Chapleau has 100% ownership of CPUC. The designate(s) that sits on the CPUC Board of Directors reports back to the Town of Chapleau. Once a year CPUC holds an official shareholders meeting where the Town council is informed what has taken place over the last year and CPUC’s provision.

The General Manager of CPUC also attends the regular council meeting(s) of the Township as needed and meets with various council members on different issues as they arise during the year.
There has been no change in how the utilty is managed from a shareholder's perspective with respect to the change from a virtual utiliyt to a tranditional utiltiy .

1.4 DISTRIBUTION SYSTEM OVERVIEW

1.4.1 APPLICANT OVERVIEW[29]

CPUC's service area is an embedded utility completely contained within the municipal boundaries of the town of Chapleau therefore the utility only serves the community of Chapleau. The area is embedded within the Hydro One Networks Inc.

The Chapleau Distribution System comprises 1 25kV feeder, 2 4160kV feeders generally supplying loads on either side of the river (F9 on the WEST, and F8 on the EAST and downtown) supplied from T4 and on a single 4160kV (F2) feeder from T3 supplying loads to the north.

The loads in the north include approximately 1500kVA of transformers that have previously been moved from the F2 to the F9 in order to off load a submersible feeder section of the F2 which is considered to be high risk of failure. This 1500kVA of connected load, more likely represents between 400 and 600kVA of actual load (approx. 50-75A)

There have been 2 capacitor banks (each 225 kVAR) installed on the F9, both located relatively close to the station, and an regulator installed 2/3 of the distance out the feeder to provide voltage support in the rural area.

The map below shows the utility's service area.[30] A more detailed PDF version of the map can be found at Appendix H.

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[29] MFR - Description of whether the distributor is a host distributor and/or embedded distributor. Identification of embedded and/or host distributors; if partially embedded provide %load from host distributor. If the distributor is a host, the applicant should identify whether there is a separate Embedded Distributor customer class or if any embedded distributors are included in other customer classes such as GS > 50 kW

[30] MFR - Description of Service Area (including map, communities served)

1 **Table 4 - Map of Service**

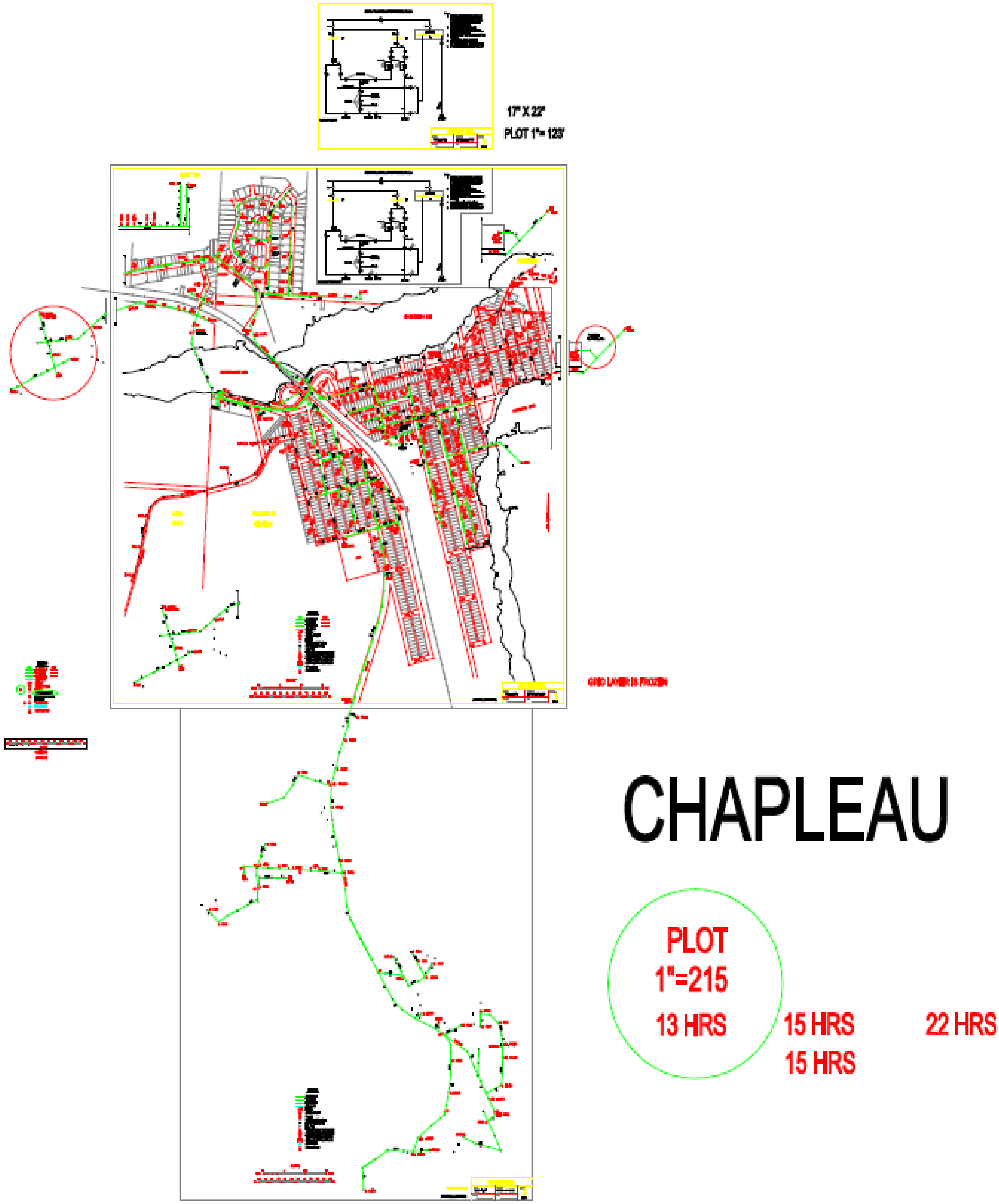

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Table 5 - Utility Description

Service Area	Description of Applicant (as of end of 2017)
Community Served	Chapleau
# of Metered Customers	1072 Residential
	162 General Service
	13 Over 50
	4 USL
	23 Sentinel
	328 Streetlights
Total Service Area	13.5 Sq. km
Rural Service Area	0 Sq. km
Average Peak	4133 kW
Host Distributor	Hydro One
Load provided by host	Hydro One

Economic Overview

CPUC's economic overview is also presented in section 2.1 of the Business Plan and duplicated below for ease of reference. A comprehensive community Profile published by the Town of Chapleau in March of 2016 is presented at Appendix I of this application.

Introduction

The Township of Chapleau is situated within the Boreal Forest and Arctic Watershed Region of Northern Ontario. Chapleau is best known for being the home of the world's largest Crown Game Preserve, as well as being the 2011 winners of WFN's Ultimate Fishing Town Canada contest. The Game Preserve, established in 1925, is 700,000 hectares in size, making it an exciting eco-tourism destination for world nature and wildlife travelers. Chapleau is also home to many different cultural communities, such as Chapleau Cree First Nation, Chapleau Ojibwe First Nation, Brunswick House First Nation, Chapleau's francophone community and Chapleau's Metis community. All of the various cultures have had a large impact on the history and upcoming of Chapleau. Deeply rooted in the fur trade and the railway, Chapleau's history began in 1885 when the Canadian Pacific Railway line provided access for the Hudson's Bay Company Trading Post. A fire in 1948 encouraged the government to develop a road so that logging contractors could remove the timber before it rotted. Consequently, Highway 129 was completed during the depression. In future years, Highways 101 and 17 were constructed to link Chapleau with Timmins to the East, and Wawa to the West (Wawa - 140 kilometres to the West and Timmins 200 kilometres to the East).

Location

Chapleau is linked to larger communities, such as Timmins and Sault Ste. Marie, via highway 101, and to Sudbury via highways 129 and 17. The Budd Car, operated by Via rail, offers train service travelling alternately east to Sudbury or west to White River with 2 stops per week in Chapleau. Travellers and residents can reach southern Ontario by Via Rail on the Canadian National Railway which stops regularly in Foleyet, which is one hour from Chapleau. International travel can be accommodated at Toronto Pearson international airport, with connecting regional air service to Timmins, Sault Ste. Marie, and Sudbury. Chapleau operates a municipal airport that is used for emergency services, and is host to the Ministry of Natural Resources base, which is used for fire suppression water bombers.

Climate

The average temperature fluctuates from a low of -16 degree Celsius in January to a high of 15.7 degree Celsius in August. From the fall of 2017 to the fall of 2018, Winter temperatures are expected to be above normal, with the coldest periods in mid-November, early and late December, early January, and early and mid-February. Precipitation and snowfall are expected to be above normal in the east and below normal in the west, with the snowiest periods in late November, mid- and late December, and early to mid-March. April and May are expected to be a bit cooler than normal, with near-normal precipitation. Summer will be hotter than normal, with rainfall below normal in Southwest Ontario and above normal elsewhere. The hottest periods will be in early and late June, early July, and mid- to late August. September and October will be warmer and slightly drier than normal.

Labour Force

Chapleau is home to a labour force that is 1,735 persons strong. Chapleau's labour participation rate and employment rate are higher than the Ontario average.

Participation rate % 75.24 in Chapleau vs. 66.3% in Ontario. Employment rate % 63.26 in Chapleau vs. %61.3 in Ontario and Unemployment rate %15.93 in Chapleau vs. %7.4 in Ontario.

The largest percentage of labour force (by industry) in Chapleau is employed in the Transportation and Warehousing industry, which accounts for 23.5% of the labour force compared to 4.5% for Ontario. The percentage of labour force in the Health Care and Social Assistance industry (13.3%) and in the Manufacturing industry (12%) locally are also high. The largest private sector employers are Canadian Pacific Rail with 165 employees; Tembec with 150 Employees; True North Timber with 85 employees and Chapleau Valu-mart with 42 employees. The largest public sector employers are Chapleau High School, Chapleau Health Services; Chapleau Child Care Centre; Ministry of Natural Resources and the Township of Chapleau.

1.4.2 HOST /EMBEDDED DISTRIBUTOR

CPUC is an embedded distributor who receives electricity at distribution level voltages from Hydro One Networks Inc.

CPUC does not have any embedded distributors within its territory. [31]

1.4.3 TRANSMISSION OR HIGH VOLTAGE ASSETS

Per ANSI standard C84.1-1989, "Low" voltage is described as 600V and below. "Medium" voltage is 2.4kV through 69kV. "High" voltage is 115kV through 230kV and "Extra-High" voltage is 345kV to 765kV, while "Ultra-high" voltage is 1.1MV. The higher voltage of the transformer (primary or secondary) is the voltage on which the transformer is designated.

CPUC currently operates a 115KV substation, which based on the definition above, could be classified as "high-voltage."[32]

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[31] MFR - Identification of embedded and/or host distributors; if partially embedded provide %load from host distributor. If the distributor is a host, the applicant should identify whether there is a separate Embedded Distributor customer class or if any embedded distributors are included in other customer classes such as GS > 50 kW

[32] MFR - Statement as to whether or not the distributor has had any transmission or high voltage assets deemed by the OEB as distribution assets and whether or not there are any such assets the distributor is seeking approval for in this application

1.5 APPLICATION SUMMARY

This section is devoted to defining each element of CPUC's 2019 cost-of-service, explaining how each element is determined and explaining the relationship between the various components. The major components covered in this application summary are as follows:

- ✓ Budgeting Assumptions
- ✓ Revenue Requirement
- ✓ Rate Base and Capital Planning
- ✓ Overview of Operation Maintenance and Administrative Costs
- ✓ Load Forecast Summary
- ✓ Statement of Cost of Capital Parameters
- ✓ Overview of Cost Allocation and Rate Design
- ✓ Overview of Deferral and Variance Account Disposition
- ✓ Overview of Bill Impacts

Budgeting and Economic Assumptions[33]

CPUC compiles budget information for the three major components of the budgeting process: (1) revenue forecasts; (2) operating, maintenance and administration ("OM&A"); and (3) capital costs.

Revenue Forecast

The revenue forecasts are based on throughput volume and existing rates for the 2018 Bridge Year and CPUC's proposed rates for the 2019 Test Year. The forecasted volumes have been weather normalized and consider such factors as new customer additions and load for all classes of customers. Details are presented in Section 3.1.4. of Exhibit 3. The forecast has been adjusted to reflect the CDM initiatives currently undertaken by the applicant.

[33] MFR - Budgeting and Accounting Assumptions - economic overview and identification of accounting standard used for test year and brief explanation of impacts arising from any change in standards

OM&A Costs

OM&A costs presented in Exhibit 4 show CPUC's maintenance and customer focused activity needed to meet public and employee objectives. These costs are essential in order to comply with the Distribution System Code, environmental requirements, and government direction, and to maintain distribution service quality and reliability at targeted performance levels. OM&A costs also include providing services to customers connected to CPUC's distribution system and meeting the requirements of the OEB's Standard Supply Code and Retail Settlement Code.

The proposed OM&A cost expenditures for the 2019 Test Year are the result of planning and work prioritization process that ensures that the most appropriate, cost effective solutions are put in place.

Capital Costs

In managing its capital assets, CPUC's primary objectives are to optimize asset performance cost-effectively, enhance safety, protect the environment, improve operational efficiency, maintain high standards of reliability, adhere to regulation and meet customer demand. As part of the development of its Distribution System Plan, CPUC develops capital programs on both a short and longer-term basis and prepares annual budgets and forecasts as the basis for capital investments. CPUC's approach to managing its distribution system is comprised of the following strategy:

System Planning; add new assets and/or replace assets that are at or nearing the end of their useful life. This includes consideration for:

- ✓ Capital Investment
- ✓ Contingency Planning
- ✓ Managing and Sustaining Existing Assets;

CPUC's approach to managing its distribution assets is described in more detail in CPUC's Distribution System Plan.

Capital costs in Exhibit 2 have been developed with the key strategies above in mind.

Overall Budgeting Process

The capital and operating budgets are prepared annually by management and reviewed and approved by the Board of Directors. Once approved, the budget is only revised if a material change in plan is required. In such cases, the revised budget is once again approved by the Board of Directors.

CPUC continues to deliver its operating and capital plans on target and on a budget.

Application Summary

The following section summarizes this Cost of Service application and how it measures against CPUCs last Cost of Service application in 2012.

Table 6 – 2019 Parameters vs 2012 Parameters

	CGAAP	**MIFRS**	
Particular	**2012**	**2019**	**Diff**
Long Term Debt	4.41%	4.16%	-0.25%
Short Term Debt	2.08%	2.29%	0.21%
Return on Equity	9.12%	9.00%	-0.12%
Weighted Debt Rate	4.25%	4.04%	-0.22%
Regulated Rate of Return	**6.20%**	**6.02%**	**-0.18%**
Controllable Expenses	$654,490	$829,425	$174,935
Power Supply Expense	$2,516,183	$2,692,686	$176,503
Total Eligible Distribution Expenses	$3,170,673	$3,522,111	$351,438
Working Capital Allowance Rate	15.00%	7.50%	-7.50%
Total Working Capital Allowance ("WCA")	**$475,601**	**$264,158**	**-$211,443**
Fixed Asset Opening Bal Bridge Year	$2,554,525	$3,925,018	$1,370,493
Fixed Asset Opening Bal Test Year	-$1,517,843	-$2,438,409	-$920,566
Average Fixed Asset	$1,036,682	$1,486,609	$449,927
Working Capital Allowance	$475,601	$264,158	-$211,443
Rate Base	**$1,512,283**	**$1,750,767**	**$238,484**
Regulated Rate of Return	6.20%	6.02%	-0.18%
Regulated Return on Capital	**$93,774**	**$105,417**	**$11,644**
Deemed Interest Expense	$38,606	$42,390	$3,784
Deemed Return on Equity	$55,168	$63,028	$7,860
OM&A	$644,340	$821,163	$176,823
Property Taxes	$10,150	$8,262	
Depreciation Expense	$75,576	$120,706	$45,130
PILs	$13,814	$0	-$13,814
Revenue Offset	-$41,735	-$50,729	-$8,994
Revenue Requirement	**$795,919**	**$1,004,820**	**$208,901**

Revenue Requirement[34]

The table below shows CPUC's revenue requirement from the last Cost of Service in 2012 up to the proposed 2019 revenue requirement.

The proposed Revenue Requirement for the 2019 test year of $1,004,820 reflects an increase of $208,901 or 26.25% relative to the 2012 Board Approved. The revenue requirement between 2013 and 2017 increased at a steady rate representing a deliberate pace of capital and operational investment. The increase in 2018 and 2019 is largely due to 1) an increase in depreciation expense related to the purchase of a boom truck. and 2) an increase in OM&A as a result of changing the corporate structure from a virtual utility to a standard utility 3) maintaining two management positions in an effort to plan for succession and an increase in regulatory cost related to outside services and regulatory costs .

The increase in OM&A is also attributable to an increase in Regulatory Costs. Regulatory costs are projected to be higher for 2019 due to provisions for an oral hearing and the drafting of the Distribution System Plan by a third-party engineering firm. Year over year variances in OM&A are explained throughout Exhibit 4 and Revenue Offsets and explained in detail at Exhibit 3.

[34] MFR - Revenue Requirement - service RR, increase ($ and %) from change from previously approved, main drivers

Table 7 - 2019 Proposed Revenue Requirements

	CGAAP	CGAAP	NEWGAAP	NEWGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Particular	**Last Board Approved**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
OM&A Expenses	$644,340	$670,607	$638,471	$744,673	$730,565	$744,037	$716,586	$809,404	$821,163
Depreciation Expense	$75,576	$113,903	$72,025	$72,466	$50,827	$52,874	$49,114	$154,279	$120,706
Property Taxes	$10,150	$9,885	$7,123	$7,050	$6,619	$6,989	$7,916	$8,100	$8,262
(other expenses)	*$3,000*								
Total Distribution Expenses	$733,066	$794,394	$717,619	$824,189	$788,011	$803,900	$773,615	$971,783	$950,131
Regulated Return On Capital	$93,774	$100,051	$85,488	$106,908	$103,805	$106,352	$99,272	$111,977	$105,417
Grossed up PILs	$13,814	$0	$0	$0	$0	$1,902	$4,126	$0	$0
Service Revenue Requirement	**$840,654**	**$894,445**	**$803,107**	**$931,097**	**$891,817**	**$912,154**	**$877,013**	**$1,083,761**	**$1,055,548**
Less: Revenue Offsets	-$41,735	-$36,786	-$10,058	-$30,361	$1,687	-$47,433	-$36,942	-$93,910	-$50,729
Base Revenue Requirement	**$798,919**	**$857,659**	**$793,048**	**$900,736**	**$893,504**	**$864,721**	**$840,071**	**$989,851**	**$1,004,820**

Rate Base and Capital Planning[35]

The proposed Rate Base for the 2019 Test Year of $1,750,767 reflects an increase of $238,484 from the 2012 Board Approved. The increase suggests a prudent and reasonable investment in the distribution assets and is necessary in order to meet other regulatory requirements. Capital priorities in 2018 include testing of the substation to ensure that the asset will serve CPUC's customers until its next Cost of Service. It also includes the replacement of poles and transformers as they show sign of deterioration and lastly the replacement of a aged boom truck. 2019 is projected to be back to normal yearly levels of approximately 80k.

The utility is not proposing to recover any costs from any rate class for renewable energy connections/expansions, smart grid, and regional planning initiatives. The table below shows the change in Rate Base from the last Cost of Service in 2012 to the proposed 2019 Cost of Service.

[35] MFR - Rate Base and DSP - major drivers of DSP, rate base for test year, change from last approved ($ and %), capital expenditures requested for the test year, change in capital expenditures from last approved ($ and %), summary of costs requested for renewable energy connections/expansions, any O.Reg 339/09 planned recovery, capex for test year, change from last approved, costs for any REG-related, smart grid, regional planning projects

Table 8 - Rate Base

	CGAAP	CGAAP	NewCGAAP	NewCGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Particulars	**Last OEB Board Approved**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Opening Balance	2,554,525	2,331,013	2,606,151	2,672,226	2,744,775	2,813,510	2,843,685	3,370,199	3,925,018
Ending Balance	-1,517,843	-1,421,821	-1,514,805	-1,587,030	-1,648,677	-1,700,527	-1,751,521	-2,077,067	-2,438,409
Average Balance	1,036,682	909,192	1,091,346	1,085,196	1,096,099	1,112,983	1,092,164	1,293,132	1,486,609
Working Capital Allowance	475,601	469,465	522,168	638,899	577,964	602,155	508,788	512,720	264,158
Total Rate Base	1,512,283	1,378,657	1,613,514	1,724,095	1,674,063	1,715,138	1,600,952	1,805,851	1,750,767
Year over year variance		-12.30%	20.03%	-0.56%	1.00%	1.54%	-1.87%	18.40%	14.96%

Table 9 - Working Capital Allowance

	CGAAP	CGAAP	NewCGAAP	NewCGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Expenses for Working Capital	**Last OEB Board Approved**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
3500-Distribution Expenses - Operation	205,440	289,711	220,412	223,211	208,239	236,332	237,909	247,400	242,760
3550-Distribution Expenses - Maintenance	-	-	-	-	-	-	-	-	1,610
3650-Billing and Collecting	84,200	95,585	115,086	135,609	129,895	121,157	121,220	135,000	133,730
3700-Community Relations	600	115	415	415	115	415	415	-	-
3800-Administrative and General Expenses	354,100	285,195	302,558	385,438	392,316	386,133	357,042	427,004	443,063
6105-Taxes other than Income Taxes									
	10,150	9,885	7,123	7,050	6,619	6,989	7,916	8,100	8,262
Total Eligible Distribution Expenses	654,490	680,492	645,594	751,724	737,184	751,026	724,502	817,504	829,425
3350-Power Supply Expenses	2,516,183	2,449,277	2,835,527	3,507,606	3,115,911	3,263,340	2,667,417	2,600,626	2,692,686
Total Expenses for Working Capital	3,170,673	3,129,768	3,481,121	4,259,330	3,853,096	4,014,366	3,391,918	3,418,130	3,522,111
Working Capital factor	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	7.5%
Total Working Capital	475,601	469,465	522,168	638,899	577,964	602,155	508,788	512,720	264,158

CPUC strictly follows the best practices of the electricity distribution industry. This has included adhering to the Ontario Energy Board's (OEB) Distribution System Code that sets out, among others, good utility practice and performance standards for the industry in Ontario, and minimum inspection requirements for distribution equipment. Consistent with best practices, over the years CPUC has replaced or upgraded equipment when economically viable. The net result has been that while the average age of the system has increased slightly, the reliability of the system has steadily improved to meet the expectations of CPUC's customers. This has been achieved with only a moderate long-term increase in customers' bills.

Details of historical and projected capital expenses are summarized in the table below

Table 10 - Capital Expenditure Summary

	CGAAP	NewCGAAP	NewCGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Sub-Total System Access	$439,701	$800	$0	$521	$1000	$19,668	$8,039	$0
Sub-Total System Renewal	$6,941	$12,647	$18,923	$45,854	$35,284	$17,420	$34,352	$80,667
Sub-Total System Service	$15,406	$0	$25,000	$0	$100	$0	$32,500	$0
Sub-Total General Plant	$0	$74,700	$0	$54,800	$0	$0	$401,771	$0
Contribution								
Total Capital Expenditures	$462,048	$88,227	$43,923	$101,176	$36,293	$37,088	$476,662	$80,667

Major capital cost drivers 2012

- Transfer of Smart Meters into Rate Base $381,117
- Software costs related to implementation of smart Meters $58,584
- Poles and Line Transformers $6,941
- DS oil testing and regulator $15,406

Major capital cost drivers 2013

- Meters $880
- Poles and Line Transformers $12,647
- Asset Management Plan (AMP) (Burman-Energy) $40,000
- Substation TX's Re-Inhibit and clean oil $34,700

Major capital cost drivers 2014

- Poles and Line Transformers $18,923
- Computer Software Asset Management (Burman-Energy) $25,000

Major capital cost drivers 2015

- Poles and Line Transformers $45,854
- AMP Software support – (Burman Energy) $54,800

Major capital cost drivers 2016

- Poles and Line Transformers $35,284
- Meter Services $1,000

Major capital cost drivers 2017

- Meter Sampling $19,668
- Poles and Line Transformers $17,420

Major capital cost drivers 2018

- Meter Reverification $8,039
- Poles and Line Transformers $34,352
- Station Moisture testing and service $32,500
- Boom truck $389,010
- Computer Hardware $12,761

Major capital cost drivers 2019

- Poles and Line Transformers $80.667

Details of each of these programs are presented in Exhibit 2 as well as the Distribution System Plan.

Overview of Operation, Maintenance, and Administrative Costs[36]

The increase of $176,823 in OM&A spending from its 2012 (BA) Cost of Service to the 2019 Test Year can be attributed to several factors.

Operation costs are for the most part allocated to the compensation of the two linesmen who provide maintenance of meters and overhead assets. The costs related to operations accounts increased steadily over the last 5 years and increased at the pace of inflation.

Administrative Costs include inflationary increases in salaries and the increased costs for management salaries as a result of moving to 2 management positions in 2017. The overall

[36] MFR - OM&A Expense - OM&A for test year and change from last approved ($ and %), summary of drivers, inflation assumed, total compensation for test year and change from last approved ($ and %).

costs have also increased as a result of the utility's structure change (virtual vs traditional). Major costs drivers are presented at the next page and details presented in Exhibit 4.

Table 11 - Summary of Recoverable OM&A Expenses

Reporting Basis	**CGAAP**	**CGAAP**	**NEWGAAP**	**NEWGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
	Board Approved	2012	2013	2014	2015	2016	2017	2018	2019
Operations	$205,440	$289,711	$220,412	$223,211	$208,239	$236,332	$237,909	$247,400	$242,760
Maintenance	$0	$0	$0	$0	$0	$0	$0	$0	$1,610
SubTotal	$205,440	$289,711	$220,412	$223,211	$208,239	$236,332	$237,909	$247,400	$244,370
%Change (year over year)		41.0%	-23.9%	1.3%	-6.7%	13.5%	0.7%	4.7%	-1.2%
%Change (Test Year vs Last Rebasing Year - Actual)									-15.7%
Billing and Collecting	$84,200	$95,585	$115,086	$135,609	$129,895	$121,157	$121,220	$130,000	$133,730
Community Relations	$600	$115	$415	$415	$115	$415	$415	$0	$0
Administrative and General+LEAP	$354,100	$285,195	$302,558	$385,438	$392,316	$386,133	$357,042	$427,004	$443,063
SubTotal	$438,900	$380,896	$418,059	$521,463	$522,325	$507,705	$478,677	$562,004	$576,793
%Change (year over year)		-13.2%	9.8%	24.7%	0.2%	-2.8%	-5.7%	10.7%	2.6%
%Change (Test Year vs Last Rebasing Year - Actual)									51.4%
Total	$644,340	$670,607	$638,471	$744,673	$730,565	$744,037	$716,586	$804,404	$821,163
%Change (year over year)		4.1%	-4.8%	16.6%	-1.9%	1.8%	-3.7%	13.0%	1.5%

Table 12 – OEB Appendix 2-JB – Recoverable OM&A Cost Driver Table

Reporting Basis	NEWGAAP	NEWGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
OM&A	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
OM&A Cost Drivers >$10,000	$670,607.00	$638,471.00	$744,673.00	$730,565.00	$744,037.00	$716,586.00	$809,404.00
Operation							
5020-Overhead Distribution Lines & Feeders – Operation Labour		$13,425			-$15,186	$14,393	
5025-Overhead Distribution Lines & Feeders – Operation Supplies and Expenses	$19,069	-$14,106		$22,237	$10,150		
5065-Meter Expense	-$90,957						
Billing and Collecting							
5310-Meter Reading Expense	$12,578						
5335-Bad Debt Expense		$23,102	-$10,871	-$12,137			
Administration							
5610-Management Salaries and Expenses				$27,080	$21,847	39,378	
5630-Outside Services Employed	-$18,883	$0	$61,550	-$33,890	-$11,678	- 26,046	
5635-Property Insurance				-$10,495			
5645-Employee Pensions and Benefits					$10,536	$10,158	
5655-Regulatory Expenses	$12,024	-$11,584				$33,581	$21,522
5665-Miscellaneous General Expenses		$94,880	-$56,604		-$44,485		
Misc < 1000							
Misc <5000	$34,031	$484	-$8,184	$20,677	$1,364	$21,354	-$9,763
Closing Balance	$638,471	$744,673	$730,565	$744,037	$716,586	$809,404	$821,163

CPUC only experienced a variances in excess of the materiality threshold of 50K during the 2014 which was related to a journal entry in 5665-Miscellaenous General Expenses. This variance and all other variances listed below are explained in detail at Exhibit 4 of this application.

5020-Overhead Distribution Lines & Feeders - Operation Labour

2013-2014; Increase of $13,425

2016-2017; Decrease of $15,186

2017-2018; Increase of $14,393

5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses

2012-2013; Increase of $19,069

2013-2014; Decrease of $14,106

2015-2016; Increase of $22,237

2016-2017; Increase of $10,150

5065-Meter Expense:

2012-2013; Decrease of $90,957

5310-Meter Reading Expense

2012-2013; Increase of $12,578

5335-Bad Debt Expense

2013-2014; Increase of $23,102

2014-2015; Decrease of $10,871

2015-2016; Decrease of $12,137

5610-Management Salaries and Expenses

2015-2016; Increase of $27,080

2016-2017; Increase of $21,847

2017-2018; Increase of $39,378

5630-Outside Services Employed

2012-2012 BA; Decrease of $47,802

2012-2013; Decrease of $18,883

2014-2015; Increase of $61,550

2015-2016; Decrease of $33,890

2016-2017; Decrease of $11,678

2017-2018; Decrease of $26,046

5635-Property Insurance

2015-2016; Decrease of $10,495

5645-Employee Pensions and Benefits

2016-2017; Increase of $10,536

2017-2018; Increase of $10,158

5655-Regulatory Expenses

2012-2013; Increase of $12,024

2013-2014; Decrease of $11,584

2017-2018; Increase of $33,581

2018-2019; Increase of $21,522

5665-Miscellaneous General Expenses

2012-2013; Increase of $94,880

The inflation factor used for budgeting purposes is 2.0%. Total Compensation is shown in the table below and discussed in detail in Section 4.4 of Exhibit 4.

Table 13 – OEB Appendix 2-K Total Compensation included in OM&A

	2012	2013	2014	2015	2016	2017	2018	2019
Number of Employees (FTEs including Part-Time)[1]								
Management (including executive)	1	1	1	1	2	2	2	2
Non-Management (union and non-union)	4	4	4	4	3	3	5	3
Total	5	5	5	5	5	5	7	5
Total Salary and Wages including ovetime and incentive pay								
Management (excluding executive)	$59,567	$64,246	$60,027	$60,695	$87,775	$109,622	$149,000	$149,760
Non-Management (union and non-union)	$190,803	$197,902	$213,139	$202,384	$208,649	$190,688	$218,550	$212,764
Total	$250,370	$262,148	$273,166	$263,078	$296,424	$300,309	$367,550	$362,524
Total Benefits (Current + Accrued) -								
Management (excluding executive)	$2,925	$3,132	$3,216	$3,039	$5,924	$5,123	$11,302	$11,555
Non-Management (union and non-union)	$10,793	$11,172	$11,784	$11,419	$11,740	$9,343	$6,638	$6,642
Total	$13,718	$14,304	$15,000	$14,457	$17,664	$14,465	$17,940	$18,197
Total Compensation (Salary, Wages, & Benefits)								
Management (excluding executive)	$62,493	$67,378	$63,243	$63,733	$93,699	$114,744	$160,302	$161,315
Non-Management (union and non-union)	$201,596	$209,074	$224,923	$213,802	$220,389	$200,030	$225,188	$219,406
Total	$264,088	$276,452	$288,166	$277,536	$314,088	$314,775	$385,490	$380,721

Load Forecast Summary[37]

The load forecast for 2019 is based on a methodology that predicts class specific consumption using a multiple regression analysis that relates historical monthly wholesale kWh usage to monthly historical heating degree days and cooling degree days.

In CPUC's case, variation in monthly electricity consumption is influenced by four main factors – weather (e.g. heating and cooling), which is by far the most dominant effect on most systems, the number of days per month and an "Employment" factor. Specifics relating to each variable used in the regression analysis are presented in the next section.

- ✓ Wholesale Purchases (main)
    - o Heating Degree Days (included)
    - o Cooling Degree Days (included)
    - o Unemployment (included)
    - o Days per month(included)
    - o Daylight hours

Weather normalized values are determined by using the regression equation with a "10-year average monthly degree days (2008-2017)". The 10-year average is consistent with recent years' weather and has been used in other electricity distribution rate applications accepted by the Board.

Allocation to specific weather sensitive rate classes (Residential, GS<50, GS>50) is based on the average share of each classes' actual retail kWh (exclusive of distribution losses) of actual wholesale kWh for the 2008 to 2017 period.

The 2019 Load Forecast is presented on the next page, and detailed explanations of the load forecast can be found in Exhibit 3.

[37] MFR - Load Forecast Summary - load and customer growth, % change in kWh and customer numbers, methodology description

Table 14 - Load Forecast

	2012 Board Approved	2012 Board Approved	2012 Board Approved	2019	2019	2019
Customer Class Name	**Customer**	**kWh**	**Kw**	**Customers**	**kWh**	**Kw**
Residential	1,133	14,448,113		1,033	13,831,681	
General Service < 50 kW	161	5,209,322	19,360	148	4,880,502	18,883
General Service > 50 to 4999 kW	14	7,592,321		15	7,147,174	
Unmetered Scattered Load	6	7,209	65	4	5,232	65
Sentinel Lighting	23	25,718	773	23	24,760	774
Street Lighting	341	292,061		328	283,967	
TOTAL	**1,678**	**27,574,744**	**20,198**	**1,552**	**26,173,316**	**19,722**

Statement of Cost of Capital Parameters[38]

In this application, CPUC seeks to recover a weighted average cost of capital of 6.02% through rates in the 2019 Test Year. CPUC has followed the Report of the Board on Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, as well as the Review of the Existing Methodology of the Cost of Capital for Ontario's Regulated Utilities, January 14, 2016, in determining the applicable cost of capital.

In calculating the applicable cost of capital, CPUC has used the OEB's deemed capital structure of 56% long-term debt, 4% short-term debt, and 40% equity, in conjunction with the Cost of Capital parameters in the OEB's letter of October 27, 2016, for the allowed return on equity ("ROE"). CPUC is not seeking any changes in its Capital Structure from its 2012 Board Approved Structure. CPUC notes that consistent with Board policy, it used the deemed long-term debt rate of 4.16%.

Table 15 - Overview of Capital Structure

Particulars	**Cost Rate**		**Return**	
	(%)	($)	(%)	($)
Debt				
Long-term Debt	56.00%	$980,429	4.16%	$40,786
Short-term Debt	4.00%	$70,031	2.29%	$1,604
Total Debt	60.0%	$1,050,460	4.04%	$42,390
Equity				
Common Equity	40.00%	$700,307	9.00%	$63,028
Preferred Shares		$ -		$ -
Total Equity	40.0%	$700,307	9.00%	$63,028
	100.0%	$1,750,767	6.02%	$105,417

*2019 Rate Base

CPUC commits to updating its Cost of Capital forecast in accordance with applicable OEB updates to the Board's cost of capital parameters.

[38] MFR - Cost of Capital - Statement regarding use of OEB's cost of capital parameters; summary of any deviations

Overview of Cost Allocation and Rate Design[39]

The main objectives of a Cost Allocation study are to provide information on any apparent cross-subsidization among a distributor's rate.

CPUC has prepared and is filling a cost allocation information filing consistent with the utility's understanding of the Directions, the Guidelines, the Model and the Instructions issued by the Board back in November of 2006 and all subsequent updates.

CPUC has prepared a Cost Allocation Study for 2019 based on an allocation of the 2019 test year costs (i.e., the 2019 forecast revenue requirement) to the various customer classes using allocators that are based on the forecast class loads (kW and kWh) by class, customer counts, etc.

CPUC has used the most recent Board-approved Cost Allocation Model and followed the instructions and guidelines issued by the Board to enter the 2019 data into this model.

Two of the classes' revenue to cost ratios fell outside the Board range. For those two classes, the utility proposes reallocation of revenues to reduce the impact on the bills. The table below shows the utility's proposed Revenue to Cost reallocation based on an analysis of the proposed results from the Cost Allocation Study vs. the Board imposed floor and ceiling ranges. Further details on Cost Allocation can be found in Exhibit 7.

Table 16 - Proposed Allocation

					Target Range		
Customer Class Name	Calculated R/C Ratio	Proposed R/C Ratio	Variance		Floor	Ceiling	
Residential	0.9338	0.9340	-0.00		0.85	1.15	
General Service < 50 kW	1.2004	1.2004	0.00		0.80	1.20	
General Service > 50 to 4999 kW	1.0607	1.0607	0.00		0.80	1.20	
Unmetered Scattered Load	3.7661	2.5009	1.27		0.80	1.20	
Sentinel Lighting	0.9130	1.0091	-0.10		0.80	1.20	
Street Lighting	1.1122	1.1123	-0.00		0.80	1.20	

[39] MFR - Cost Allocation & Rate Design - summary of any deviations from OEB methodologies, significant changes and summary of proposed mitigation plans

In mid-year 2015, OEB introduced a new policy for all-fixed distribution rates for residential customers. Until now, distribution rates for the residential class have been a blend of fixed and variable rates as shown below CPUC has not filed an application with the OEB since 2015 therefore has yet to comply with the requirement. CPUC's current revenue to cost ratio is 60% fixed to 40%. The residential charge is also subject to the "Distribution Rate Protection" policy that sets the charge at a maximum $36.86/month. For these reasons, CPUC proposes a 100% implementation of a fully fixed rate in this application.

For all other classes, distribution revenues are derived from a combination of fixed monthly charges and volumetric charges based either on consumption (kWh) or demand (kW). Commodity Charges and deferral and variance rate riders, along with CPUC specific other adders are added to the distribution rates to arrive at a final all-encompassing bill.

The table below shows CPUCs existing rates in comparison to the 2019 proposed rates. As can be seen, the fixed charge for the Residential class is increasing while the variable charge is decreasing. Details can be found in Exhibit 8.

Table 17 - Proposed Rates

	Proposed Rates			Proposed Rates		
Customer Class Name	Fixed Rate	Variable Rate		Fixed %	Variable %	per
Residential	$50.87	$0.0000		100.00%	0.00%	kWh
General Service < 50 kW	$35.18	$0.0266		32.58%	67.42%	kWh
General Service > 50 to 4999 kW	$193.66	$5.1694		26.61%	73.39%	kW
Unmetered Scattered Load	$21.17	$0.0285		87.22%	12.78%	kWh
Sentinel Lighting	$12.32	$21.4320		70.94%	29.06%	kW
Street Lighting	$5.68	$26.4451		52.22%	47.78%	kW

Overview of Deferral and Variance Account Disposition[40]

CPUC proposes to dispose of a credit of $53,978 related to Group 1 and a debit of $76,737 for Group 2 Variance/Deferral Accounts. The balances in Group 1 and Group 2 balances are as of December 1, 2017 and are consistent with the utility's audited financial statements.

A net debit balance of $17,719 recorded in account 1568 being the Lost Revenue Adjustment Mechanism Variance Account and a debit of $30,877 in account 1576-IFRS to CGAAP transition.

Group 1 and Group 2 DVA balances are proposed to be disposed of over two year.

CPUC confirms that it has followed the OEB's guidance as provided in the OEB's Electricity Distributor's Disposition of Variance Accounts Reporting Requirements Report.

Table 18 - Account and Balances sought for disposition/recovery[41]

		Dec 31, 2017 Balances	Allocator
LV Variance Account	1550	201,373	kWh
Smart Metering Entity Charge Variance Account	1551	(348)	# of Customers
RSVA - Wholesale Market Service Charge	1580	(106,009)	kWh
RSVA - Retail Transmission Network Charge	1584	(8,683)	kWh
RSVA - Retail Transmission Connection Charge	1586	2,135	kWh
RSVA - Power (excluding Global Adjustment)	1588	(204,757)	kWh
RSVA - Global Adjustment	1589	99,237	Non-RPP kWh
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	179,009	%
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	(4,967)	%
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	480	%
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595	(4,255)	%
Total of Group 1 Accounts (excluding 1589)		**53,978**	
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	11,866	kWh
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act	1508	32,035	kWh
Ontario Rebate for Electricity Consumers (OREC)	1508	25,180	kWh
OFHP Dirstribtuion Rate Protection (DRP)	1508	(176)	kWh
OFHP Eligible Non-RPP Consumer (GA Modifier)	1508	(0)	kWh
Retail Cost Variance Account - Retail	1518	7,831	kWh
Other Deferred Credits	2425	0	kWh

[40] MFR - Deferral and Variance Accounts - total disposition (RPP and non-RPP), disposition period, new accounts requested
[41] MFR - Proposal for disposition of any balances in existing DVAs for renewable generation and smart grid development, if applicable

Total of Group 2 Accounts		**76,737**	
LRAM Variance Account ***(Enter dollar amount for each class)***	1568	**(17,719)**	
(Account 1568 - total amount allocated to classes)		(17,719)	
Variance		**0**	
Renewable Generation Connection OM&A Deferral Account	1532	**0**	kWh
Variance WMS - Sub-account CBR Class B (separate rate rider if no Class A Customers)	**1580**	**(2,080)**	**kWh**
Total of Group 1 Accounts (1550, 1551, 1584, 1586 and 1595)		**364,744**	
Total of Account 1580 and 1588 (not allocated to WMPs)		**(310,766)**	
Balance of Account 1589 Allocated to Non-WMPs		**99,237**	
Group 2 Accounts (including 1592, 1532)		**76,737**	
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component	1575	0	kWh
Accounting Changes Under CGAAP Balance + Return Component	1576	30,877	kWh
Total Balance Allocated to each class for Accounts 1575 and 1576		**30,877**	

Overview of Bill Impacts[42]

A summary of the bill impacts by class is presented below. Detailed explanations of the bill impacts are presented in Exhibit 8.

Neither a rate plan nor a mitigation plan are required as all of CPUC's bill impacts fall below the 10% threshold.

Several classes exceed the 10% namely the Residential class at the 10th percentile threshold, Street Lighting and Sentinel Lighting. CPUC confirms that it has abided by Board Policy on all aspects of rate design and has also explored various scenarios with respect to the disposition of deferral and variance account and other rate riders (1568 LRAMVA/1576). (CPUC notes that a longer disposition period results in rate riders of nil as they are too small).

[42] MFR - Bill Impacts - total impacts ($ and %) for all classes for typical customers

As a form of rate mitigation, CPUC is proposing to explore, during settlement, deviating from Board policy with respect to adjustments to revenue/costs ratios and fixed to variable.

CPUC notes that it may need to establish a foregone revenue rider to address the 2018 IRM application filed in February of 2018 and is still pending.

For the initial application, CPUC proposes the following disposition periods for the clearance of its deferral and variance accounts. The utility fully expects that this may change throughout the application, during settlement or post decision.

Table 19 - Bill Impacts associated with Revenue Requirement

			$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	Kwh	750	$4.70	4.04%
GENERAL SERVICE LESS THAN 50 kw SERVICE CLASSIFICATION - RPP	Kwh	2,000	$25.95	9.12%
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION - Non-RPP (Retailer)	Kw	115	$368.52	5.39%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	Kwh	60	-$4.45	-11.85%
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	Kw	1	$12.32	24.77%
STREET LIGHTING SERVICE CLASSIFICATION - RPP	Kw	64	$505.81	12.54%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	Kwh	405	$9.21	9.83%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	Kwh	750	$5.06	3.38%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	Kwh	405	$8.56	11.44%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	Kwh	1,200	$4.63	2.12%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	Kwh	1,200	$4.63	2.12%
GENERAL SERVICE LESS THAN 50 kw SERVICE CLASSIFICATION - Non-RPP (Retailer)	Kwh	2,000	$27.92	7.49%
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION - Non-RPP (Retailer)	Kw	115	$368.52	5.39%

The impact is further adjusted by overall credit rate riders to dispose of the significant balances owed to ratepayers that have accumulated in certain variance accounts. Decreases in rates for retail transmission service and wholesale market service also contribute to reducing the utility's distribution rates further.

1.6 MATERIALITY THRESHOLD

The Minimum Filing Requirements state that a distributor with a distribution revenue requirement less than $10 million must use $50,000 as a materiality threshold. With a proposed base revenue requirement of $1,004,820, CPUC has used this amount as a materiality threshold throughout this application.[43]

[43] MFR - Materiality threshold; additional details beyond the threshold if necessary

1.7 CUSTOMER ENGAGEMENT

1.7.1 OVERVIEW OF CUSTOMER ENGAGEMENT

CPUC admits that until this Cost of Service, it had taken a passive more reactive approach to customer service but that in preparing the application, CPUC was reminded of the value of the Renewed Regulatory Framework for Electricity which contemplates enhanced engagement between distributors and their customers to better align a distributor's operational plans with its customers' needs and expectations.

In response, CPUC is increasing its efforts in engaging customers to understand their needs better. CPUC always has, and will continue to focus on its customers by striving to provide superior service to its customer base. The utility is investing time and effort in new capabilities, programs, and technologies that allow it to communicate more effectively and efficiently with our customers. Some of CPUC's current and future initiatives include.[44]

- ✓ Improved Communication with Customers during calls.
- ✓ Customer satisfaction survey
- ✓ Outage Notification – Planned and unplanned
- ✓ Increase Use of Social Media, contests, promotions, etc.
- ✓ Overhaul of the utility's website (2019-2020)
    - o New educational section of the website
    - o Major Project
    - o Promotion of Conservation and Demand Management Programs

[44] MFR - Overview of customer engagement activities; description of plans and how customer needs, preferences and expectations have been reflected in the application.

The RRFE states that the OEB "believes that emphasizing results rather than activities, will better respond to customer preferences, enhance distributor productivity and promote innovation."

There are four categories of outcomes under the RRFE: customer focus, operational effectiveness, financial performance and public policy responsiveness:

Since the beginning of 2018, CPUC has taken the following steps towards OEB's RRF vision

Customer Focus*: Customer engagement is now an explicit and vital component of the regulatory framework. Utilities are expected to develop a genuine understanding of their customers' interests and preferences and reflect those interests and preferences in their business plans. Utilities are expected to demonstrate value for money by delivering genuine benefits to customers and by providing services in a manner which is responsive to customer preferences.*

CPUC steps to improve Customer Focus

- Build new website (on hold but scheduled for 2019)
- Built a customer engagement outreach plan.
    - Increase use of Facebook and Twitter.
- Build a Business Plan and post on the website once 2019 rates are approved.
- Replace old Ontario Hydro logo with a newly re-designs logo. (At no cost).
- Operate under Chapleau Hydro instead of Chapleau PUC
- Adopt proactive vision regarding asset maintenance.
- Improve communication with the customer regarding replacement of major assets (substation in next CoS)

Operational Effectiveness: *Utilities are expected to demonstrate ongoing continuous improvement in their productivity and cost performance while delivering on system reliability and quality objectives. The OEB will assess performance trends and look for evidence of strong system planning and good corporate governance. The OEB will use benchmarking to assess a utility's performance over time and to compare its performance against other utilities.*

Utilities are expected to demonstrate value for money by presenting plans for delivering services that meet the needs of their customers while controlling their costs.

<u>CPUC steps to improve Operational Effectiveness</u>

- Dismantle virtual structure and replace with the conventional structure.
- Review Vacation Pay policy and make necessary revisions to address gaps.
- Review Corporate Structure.
- Put in place Capital Expenditure Business Case Template.
- Review and update internal policies.
- CPUC hires Metsco to conduct a Load Flow and Substation Evaluation study.
- CPUC hires Metsco to update the DSP filed as part of the application .
    - TESI contacts the OEB for guidance on updating a DSP conducted by a 3rd party engineering firm. (Burman to Metsco)
- CPUC reviews its organizational structure and hires a firm to review industry standards as far as job titles and job description. The focus of the exercise is to make sure that the right people are in place for the work and that there is back up and succession planning in place.
- CPUC adopts new titles and job descriptions.

Public Policy Responsiveness: *Utilities are expected to consider public policy objectives in their business planning and to deliver on the obligations required of regulated utilities. These obligations may evolve over time and therefore this Handbook does not provide a comprehensive list of all requirements. Utilities are expected to demonstrate that they have considered Conservation First in their investment decisions. The OEB will expect to see proposals for how distributors are supporting low-income customers through programs such as LEAP and/or OESP , or through other distributor-specific programs. Electricity distributors and transmitters are expected to expand or reinforce their systems to accommodate the connection to their system for renewable energy generation facilities and the OEB expects their system plans to include details on how they will meet this requirement. Natural gas utilities are expected to identify investments or programs that have been planned to meet obligations under Ontario's cap and trade program.*

CPUC steps to improve Public Policy Responsiveness

- Review Targets
- Replace Burman Energy with Customer First.
- Ask Customer First for quarterly updates
- Understand and keep better track of LRAMVA

Financial Performance: *Utilities are expected to demonstrate sustainable improvements in their efficiency and in doing so will have the opportunity to earn a fair return. The OEB will monitor the financial performance of each utility to assess continuing financial viability and to determine whether returns are excessive. Utilities have a choice of rate-setting methods to meet their particular needs. Additional tools are available to support infrastructure investment. Utilities must report comprehensive and consistent information, allowing for comparisons over time and across utilities. The OEB will act on its obligations to ensure a financially viable sector where performance indicates that a regulatory response is needed.*

CPUC steps to improve Financial Performance

- Review of regulatory and financial reporting
- Put in place financial tools to better keep track of expenses and keep track of variances.
- Forecast pro-formas and high level ROE calculations up to 2023
- Review Accounting practices and historical results (in progress)
- Review Bad Debt accounting procedure with KPMG and Board Staff and make adjustments.
- Dismantle virtual structure and replace with the conventional structure.
- Share financial results with customers

In addition to the steps listed above, CPUC commits to improving its overall communication with its customers by adopting the approach described below.

Improved Communication with the Customers during calls: CPUC's Customer Engagement Strategy focuses on achieving goals such as engaging customers using a variety of methods and channels to understand their needs and preferences; enhancing the customer service experience for CPUC's customers by offering services that meet or exceed their expectations; improving efficiency thereby lowering costs where possible and increase consumer energy literacy.

While **reliable service** and **value** continue to be key drivers of satisfaction, CPUC believes that a customer's evaluation of their utility is also determined by the quality of their **customer service experience**.

Among the three major drivers of customer satisfaction, **reliability**, given its already high levels, offers little incremental room for improvement, and customers' perception of "**value**" is inherently subject to distributor bill impacts as well as the overall price of energy. The clear implication is that utilities seeking to make a meaningful impact on customer satisfaction should turn their focus to **customer service**.

Most customer interactions revolve around outages, cost of electricity, or other issues with a negative connotation. Despite this negative connotation, CPUC believes that these incidents often represent utilities' best opportunity to drive important business outcomes, from improved customer satisfaction, to lower cost to serve, to greater cross-promotion of new services such as CDM programs.

CPUC, therefore, believes that a more nuanced approach to customer engagement that prioritizes quality over quantity is appropriate in its case.

CPUC has identified key moments in the customer lifecycle that apply to CPUC's customer interactions. CPUC believes that these key moments represent the best opportunity to drive specific, measurable outcomes such as improved satisfaction. The identifiable key moments include the following;

- Move in / move out

- Billing inquiries
- Technical issues
- Loss of supply (outage)
- Home renovations and upgrade
- Rate Change

Customers generally contact their utility for very predictable reasons. Knowing this, CPUC's team is looking to capitalize on the highest-leverage opportunities for engaging with its customers. The key moments listed above represent the best opportunity to drive specific, measurable outcomes such as improved satisfaction, obtain feedback and recommendations from customers and enhanced cross-promotion of new services, all of which align with fundamental objectives of customer engagement.

In advance of its 2019 Cost of Service, the utility opened lines of communication with its customers to get valuable feedback on the utility's proposed capital and operational budget. The utility further engaged with its customers using the following activities.

✓ **<u>Press Release</u>**

Press release distribution is an inexpensive method of reaching out to customers. When compared with paid advertising, press release distribution is almost always the more affordable option.

CPUC also sees a press release as a way of boosting the company's visibility which is important for a small utility. A press release such as the one issued by CPUC let customers know who we are, what we do, and why they need us. . [45] [46] [47] [48]

✓ **<u>Website Update</u>**

The utility has updated its website to show it's current and upcoming capital projects. This new section of the website will be updated monthly so that CPUC's customers

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[45] MFR - Discussion on how customers were informed of the proposals being considered for inclusion in the application and the value of those proposals to customers i.e. costs, benefits, and the impact on rates
[46]MFR - Reference to any other communication sent to customers about the application i.e. bill inserts, town hall meetings or other forms of out reach and the feedback received from customers through these engagement activities
[47] MFR - Discussion on how customers were informed of the proposals being considered for inclusion in the application and the value of those proposals to customers i.e. costs, benefits, and the impact on rates
[48] MFR - Discussion of any feedback provided by customers and how the feedback shaped the final application

can understand and comment on the utility's decision regarding its operational and capital planning.

✓ **<u>Info letter via bill insert</u>**

Bill inserts are an excellent way to communicate relevant information to our customers. CPUCs has created an electronic letter which was (we don't have any email addresses) posted on Facebook and Twitter.

Although the utility did not receive much feedback from its customers, CPUC is confident that with the communication plan in place, the utility's capital budget, as proposed in the Distribution System Plan, supports CPUC's customer priority and preferences. The feedback received implies that CPUC customers trust their utility's decision makers to make sound and prudent financial and operational decisions on their behalf. CPUC notes that the capital budget was revised after the newsletter was published and that CPUC took advise from all stakeholders including Metsco, the Board of Directors, customer feedback and its consultant before it opted to update its budgets. 49

The priority going forward is to maintain CPUC's distribution assets in proper order and manage its distribution system so that the utility can provide electricity to its customers in a reliable and responsible manner. Other priorities involve maintenance of its poles and meters at a steady pace to minimize rate shock.

CPUC is aware that the OEB will most likely hold a community meeting following the filing or the application. The PowerPoint presentation used to communicate with the customer was put together using templates from previous community meeting material. The slideshow can be found at Appendix K of this Exhibit.[50][51]

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[49] MFR - Impact of customer engagement activities on the development of the capital plan are to be filed as part of the capital plan requirements in Chapter 5

[50] MFR - Provide relevant customer and local knowledge for (community) meeting planning purposes, preparing presentation and other materials as may be required, attending the meeting and having one or more executives of the distributor available to present the distributor's rate application information and answer customer questions

[51] MFR - Required to advertise the OEB's community meeting(s) on a bill insert developed by the OEB in the next available billing cycle following the filing of the application or sooner. The OEB may require the distributor to advertise the meeting(s) through other channels

Customer satisfaction survey: CPUC conducted its bi-annual Customer Satisfaction Survey in 2017 and then again in the Spring of 2017 in advance of the Cost of Service. The survey and results are discussed in the next Section (1.7.2) of this Exhibit.

Use of Social Media, contests, promotions, etc.: Social Media is a useful and powerful tool that can be used effectively to help address challenges and reinforce activities undertaken by the utility. CPUC has recently activated a Twitter account and Facebook page. The utility intends on communicating important information with its customers through twitter, Facebook, website as well as local newspapers.

Table 20 - OEB Appendix 2-AC – Customer Engagement Activities[52]

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.
Newsletter	Comments received via Facebook	CPUC responded (see appendix)
Information posted on the Website	No comments on proposed capital budget.	No action required
Customer Satisfaction Survey	List of comments is presented at Appendix E of this Exhibits	No action taken
Adoption of a Customer Outreach and Communication Plan	For internal purposes	No action required

[52] MFR - Complete Appendix 2-AC Customer Engagement Activities Summary - identify how outcomes have shaped the application

1.7.2 CUSTOMER SATISFACTION SURVEY

As part of a commitment to provide customers with reliable and quality utility services that meet current and future needs, CPUC surveyed its customers in April of 2017 receiving 179 responses.

The objectives of the survey included measuring;

- ✓ Utility's overall performance.
- ✓ Reliability.
- ✓ Billing and Payment Options
- ✓ The quality of service provided by customer care.
- ✓ The quality of service provided by field employees.
- ✓ Customer support for greater use of renewable energy.
- ✓ Customer opinions regarding how aggressively sustainable practices should be pursued.
- ✓ Cost of Electricity
- ✓ Overall Performance

The survey was developed in-house through a collaborative effort of, Hearst Power Distribution Company Limited Inc. Chapleau PUC., Hydro Hawkesbury, Cooperative Hydro Embrun and Hydro 2000 Inc. ("The Group"). (Note that Chapleau was not involved in the drafting of the survey but is now using it as their bi-annual survey) 2017's survey was created by Hearst using the Survey Monkey site.

The main purpose of the collaborative effort was to minimize the cost of the survey by the sharing of intellect and resources.

CPUC felt that using a in-house survey gives the utility more control and flexibility surrounding the delivery of the survey.

The utility used Survey Monkey to publish its survey and posted it on its website. A bill insert communicating the survey and prize was included in all bills. The ideal recommended sample size is determined to be 286. The margin of error is a measure of the precision of a sample estimate of the population value. It uses probability to substantite the precision of a sample estimate by providing a range of values in which a sample value would be expected to fall. The utility received 179 responses. The utility understand that the results may not be entirely representative of the customer's opinion and the utility commits to trying to improve its response rate in future surveys, however the utility submits that the 179 responses are the best results the utility could get. Going forward, the utility expects to focus its efforts on improving its communication with its customers.

The utility intends on continuing surveying its customers on a bi-annual basis in an effort monitor and assess residential and commercial customer knowledge, perceptions and satisfaction regarding utility services.

The utility calculated a overall satisfaction of CPUC customer who responded to the survey was 95%

Table 21 – Calculation of Overall Customer

Chapleau Public Utilities Corporation Customer Satisfaction Survey

In general, how would you rate CPUC's overall performance in serving you?

Answer Options	**Response Percent**	**Response Count**	Point Allocation	Points Accumulated
Excellent	50.7%	77	1.00	77.00
Good	44.1%	67	1.00	67.00
Fair	4.6%	7	0.00	0.00
Poor	0.7%	1	0.00	0.00
answered question		**152**	Total Points accumulated	144.00
skipped question		**27**		
			Score	95%
	This result gets reported on 2.1.19 RRR April Filing			

1.8 LETTERS OF COMMENT

1.8.1 LETTER OF COMMENT

On the 15th of August, CPUC published a notice announcing its intent on filing an adjustment to its rates. The notice which is presented at Appendix F of this exhibit was posted on Facebook, Twitter, included as part of the bills, posted in the newspaper and finally posted on the utility's website. CPUC also posted a PowerPoint presentation which provided more detailed information on the costs sought and reasons for the increase. The presentation can be found at Appendix I of this Exhibit. The utility did not receive any letter per se however, several comments and questions were posted on the utility's Facebook page. All questions and responses are presented at Appendix K of this exhibit. [53]

[53] MFR - All responses to matters raised in letters of comment filed with the OEB.

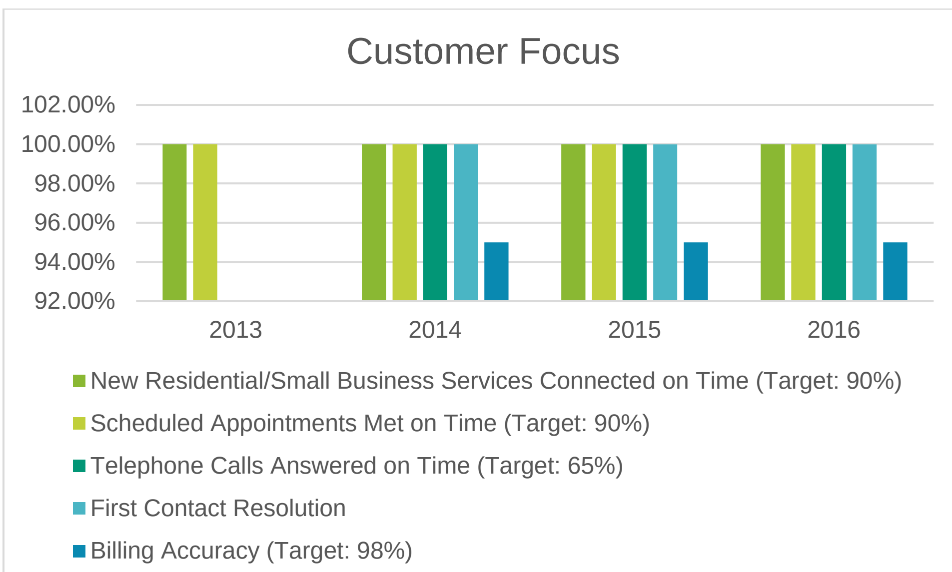
1.9 SCORECARD ANALYSIS

1.9.1 SCORECARD RESULTS AND ANALYSIS[54]

Discussion of performance of each of CPUC's scorecard measures over the last five years is presented in Section 5.6 of the Business Plan and replicated below. CPUC notes that it has used the most up to date scorecard analysis as published on the OEB website.

Customer Focus - Service Quality

From the period of 2013-2016, the utility 's results were 100%. CPUC notes that its service area has had no growth since its last Cost of Service in 2012. Distribution system investments to date have focused on sustaining the existing distribution system infrastructure.



Customer Focus - Customer Satisfaction

CPUC has conducted its bi-annual customer satisfaction survey which is presented at Section 1.7 of this Exhibit. Customers are generally satisfied (95%) with CPUC. While CPUC manages less

[54] MFR - Discussion of performance for each of the distributor's scorecard measures over the last five years; drivers for its performance, plans for continuous improvement, identify performance improvement targets, forecast of efficiency assessment using the PEG forecasting model for the test year, discussion on how distributor's self-assessment has informed its business plan and the application

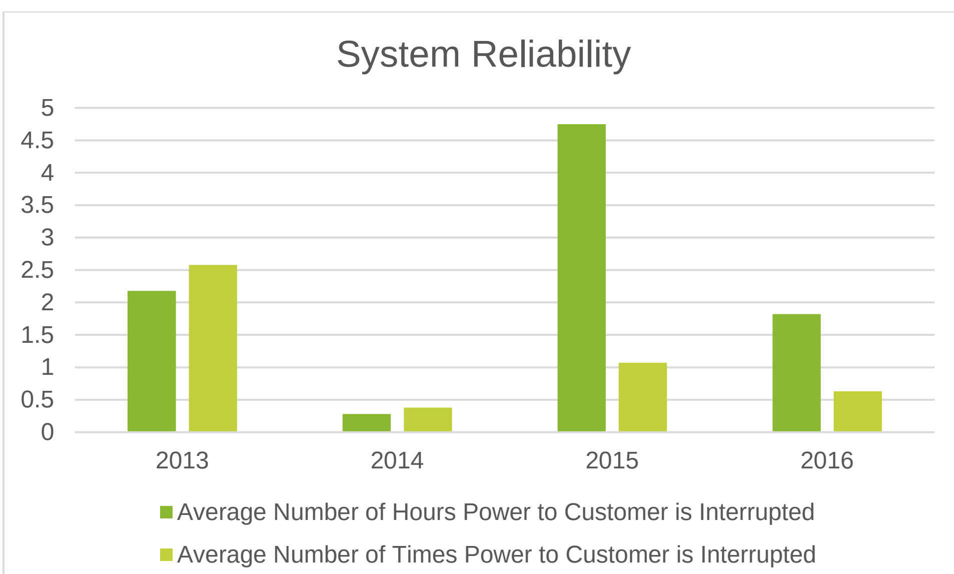
than 17% of the total customer bill, it continues its efforts to maintain appropriate cost control while providing a safe and reliable delivery of power to its customers. First Contact resolution has remained high over the period of 2013-2016 as has the Billing Accuracy with results of 100% in 2013-2014 and 99.99% in 2015 and 2016.

Operational Effectiveness - Safety

Safety remains a core attribute of CPUC's as it delivers power to its employees and customers daily. CPUC continues to strive to communicate on safety throughout our distribution system through various methods including safety orientations, on-line, and community outreach. Results over the past 4 years show 100% success in both measures of the Serious Electrical Incident Index.

Operational Effectiveness - System Reliability

The reliability of the system remains a cornerstone of CPUC with attention to vegetation management (mostly tree trimming), and re-investment in the distribution system infrastructure. 2015 showed abnormally high indicators however, other years show excellent results.

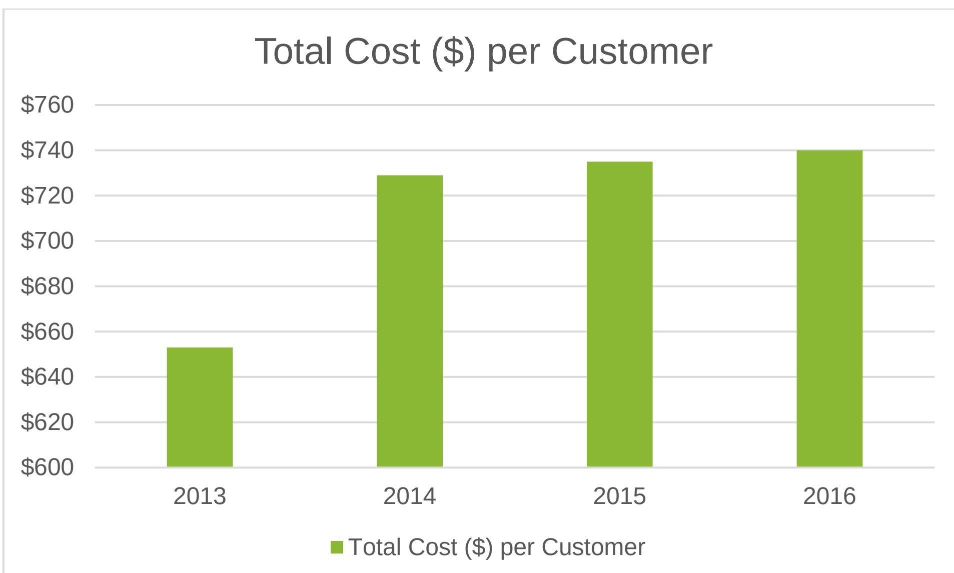


Operational Effectiveness - Asset Management

The Distribution System Plan detailing the utility’s historical and projected capital plan can be found in Exhibit 2 of this application.

Operational Effectiveness - Cost Control

CPUC has been assigned a Group 4 efficiency ranking since 2013. Although CPUC recognizes that its result fall short of industry standards, the utility continues to strive to achieve greater efficiency through productivity improvements and cost control, without compromising safety and reliability. The utility is actively looking for ways of finding efficiencies in its Operation and Maintenance form the next rate period.



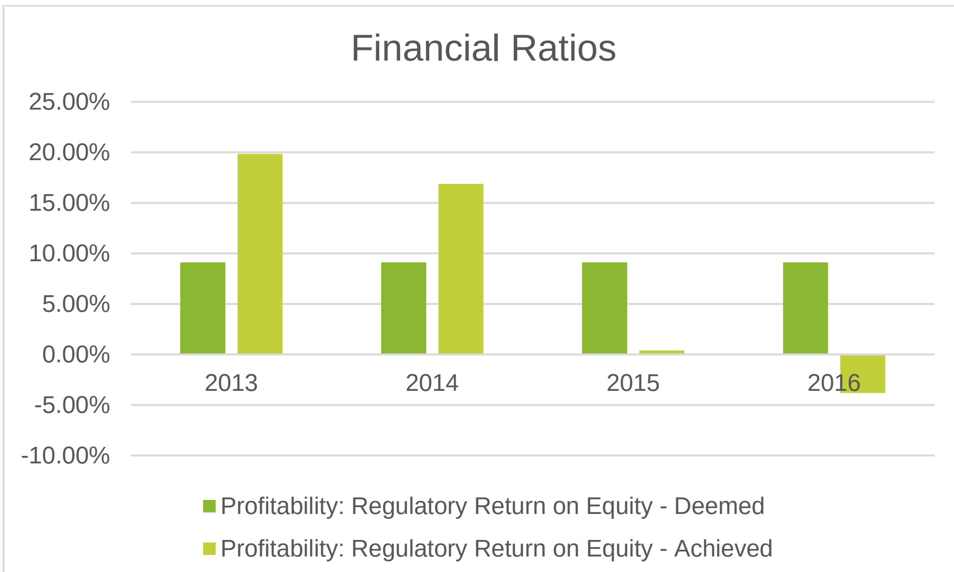
Public Responsiveness - Conservation & Demand Management

Under the new regulations, CPUC has developed a CDM plan to meet the 2015-2020 energy targets under the Conservation First Framework. CPUC has submitted and received approval from the IESO on the Conservation First Framework 2015- 2020 CDM Plan. The CDM plan has being filed in conjunction with this application

Public Responsiveness - Connection of Renewable Generation

CPUC does not currently have MicroFit connections. Should there be in the future, CPUC commits to connecting them within the allotted timeframe. CPUC will continue to provide the staff resources to maintain an efficient and effective methodology to connect renewable installations.

Financial Performance - Financial Ratios



CPUC has struggled in the past to keep its ROE in line with its Deemed ROE of 9.12% a task which is sometimes difficult for small utilities where any spending out of the ordinary can have a material effect on results. Since early 2017, the utility has put financial tools in place to monitor its budgets and compare them to its approved budgets to ensure that they are kept in line with its deemed results. CPUC anticipates more stable results between the current rebasing and next rebasing.

Overall

CPUC has continued to reflect a customer focused, financially sound, safe and reliable Local Distribution Company. Customer satisfaction and feedback inform and influence CPUC's operations, which are reflected in the continued low number of dissatisfied customers. CPUC continues to be a financially strong company that re-invests in technology that will bring improvements to customer interactions, system reliability, and safety.

The table below shows the current Scorecard on the OEB website.

Scorecard - Chapleau Public Utilities Corporation

8/27/2018

Performance Outcomes	Performance Categories	Measures		2013	2014	2015	2016	2017	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		100.00%	100.00%	100.00%	100.00%	100.00%		90.00%	
		Scheduled Appointments Met On Time		100.00%	100.00%	100.00%	100.00%	100.00%		90.00%	
		Telephone Calls Answered On Time		100.00%	100.00%	100.00%	100.00%	99.68%		65.00%	
	Customer Satisfaction	First Contact Resolution			100%	100	100	100			
		Billing Accuracy			100.00%	99.99%	99.99%	99.99%		98.00%	
		Customer Satisfaction Survey Results			95%	95	95	95			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness				76.00%	76.00%	79.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	NI	C	C	C			C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0			0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000			0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		2.18	0.28	4.75	1.82	0.94			1.36
		Average Number of Times that Power to a Customer is Interrupted [2]		2.58	0.38	1.07	0.63	0.69			0.92
	Asset Management	Distribution System Plan Implementation Progress			0%	50	100	75			
	Cost Control	Efficiency Assessment		4	4	4	4	4			
		Total Cost per Customer [3]		$653	$729	$735	$740	$718			
		Total Cost per Km of Line [3]		$30,175	$33,329	$33,436	$34,163	$29,706			
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]				26.22%	44.81%	66.56%			1.05 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time									
		New Micro-embedded Generation Facilities Connected On Time								90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.75	2.04	2.05	2.03	1.95			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		0.00	0.00	0.00	0.00	0.00			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.12%	9.12%	9.12%	9.12%	9.12%			
			Achieved	19.84%	16.88%	0.40%	-3.82%	-1.99%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the new 2015-2020 Conservation First Framework.

Legend: 5-year trend: up, down, flat. Current year: target met, target not met.

1

1.10 FINANCIAL INFORMATION

The OEB's RRFE for electricity distributors includes Financial Performance as one of the performance measurements. The four-financial metrics included are liquidity, leverage, deemed return on equity and achieved a return on equity. CPUC'S metrics for historical years 2012 to 2017, the 2018 Bridge Year and the 2019 Test Year are discussed in detail in Section 8 of the Business Plan. CPUC has replicated the information below for ease of reference.

Table 22 – Financial Ratios from Scorecards

Financial Ratios

	Liquidity: Current Ratio (Current Assets/Current Liabilities)	Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	Profitability (Approved ROE)	Regulatory Return on Equity (Achieved ROE)
2012	1.69	0.00	9.12	-17.50%
2013	1.75	0.00	9.12	19.84
2014	2.04	0.00	9.12	16.88
2015	2.05	0.00	9.12	0.40
2016	2.03	0.00	9.12	-3.82
2017	1.96	0.00	9.12	-1.99

1.10.1 FINANCIAL RESULTS

CPUC's financial performance has been unstable since its last Cost of Service application in 2012. Over the past six years, CPUC has seen its income fluctuate from a deficiency of $151,846 in 2012 Actual to a sufficiency of 53,384 in 2015. The biggest deficiency is predicted to be in 2018. This as a result of the change in the utility's corporate structure. On January 1, 2018, the utility went from a "virtual utility" to a "traditional utility.

By the end of 2018, CPUC will be under-earning due mainly to the fact that the utility was being subsidized by an affiliate. The affiliate was reporting a loss and as such closed its doors on December 31, 2017.

Another reason for the deficiency is that the utility's depreciation expense increased as a result of the purchase of a new boom truck. Details regarding the vehicle are presented in the utility's Distribution System Plan, and details relating to one-time costs are explained in the utility's Cost of the Service application, specifically throughout Exhibit 4. The rate on return for 2019 is expected to be 9.00% as prescribed by the OEB.

Actual Return vs. Allowed Return

Liquidity: Current Ratio (Current Assets/Current Liabilities)

CPUC's current liquidity ratio increased slightly from 1.69 in 2012 to 2.03 in 2016 and stabilized at 1.96 in 2017. CPUC is of the view that its ratios are indicator of good financial health. CPUC expects liquidity to remain stable if not improve going forward.

Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio

The utility does not currently have any debt. However, by Board policy, the utility used a deemed capital structure of 60% debt, 40% equity when establishing its proposed rates.

Profitability: Regulatory Return on Equity – Deemed (included in current rates) vs Achieved (2016)

CPUC's current distribution rates were approved by the OEB in 2012 and included an expected (deemed) regulatory return on equity of 9.12%. The OEB allows a distributor to earn within +/- 3% of the expected return on equity.

CPUC's actual return on equity has historically been outside of the dead band of 3% which indicates either an overearning or underearning in comparison to the Board Approved 2012 rate of return.

Unplanned or unusually large expenses tend to have more impact on small utilities than on large utilities. That said, in anticipation of an on-going disproportion in ratios, CPUC has put special financial management tools in place to make the most efficient and practical use of their resources.

Table 23 - Return on Equity Table

Profitability (Approved ROE)	**Regulatory Return on Equity (Achieved ROE)**
9.12	-17.50%
9.12	19.84
9.12	16.88
9.12	0.40
9.12	-3.82
9.12	-1.99

Profit and Loss

Outlined below, and in the following table, are some of the essential components of the projected profit and loss for CPUC:

- ✓ Operating Revenues for 2018 and 2019 are forecast to be $877,471 and $1,055,548.
- ✓ Cost and Expenses for 2018 and 2019 are predicted to be $971,783 and $950,131.
- ✓ Taxes for 2018 and 2019 are predicted to be $0 and $0 respectively.

The net profit/loss for 2018 and 2019 are forecast to be $-98,332 and $63,028, respectively

CPUC anticipates that under the new corporate structure and with the new financial tracking tools in place, the utility will be able to maintain its utility income at the level approved by its regulator.

Table 24 - Profit and Loss Table

	Board Approved	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Projected**	**Projected**
WCA	**2012**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Cost of Power	2,516,183	2,449,277	2,841,690	3,507,606	3,115,911	3,263,340	2,667,417	2,600,626	2,692,686
WCA Rate	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	7.50%
	475,601	*469,465*	*523,093*	*638,899*	*577,964*	*602,155*	*509,925*	*512,720*	*264,158*
Utility Income	**2012**	**2012**	**2013**	**2014**	**2015**	**2016**	**2016**	**2017**	**2018**
Operating Revenues									
Distribution Revenues	798,919	691,158	865,499	948,351	830,055	784,831	769,956	783,561	1,004,820
Other Revenue	41,735	36,786	10,058	30,361	-1,687	47,433	36,942	93,910	50,729
Total Operating Revenues	**840,654**	**727,944**	**875,558**	**978,712**	**828,367**	**832,264**	**806,898**	**877,471**	**1,055,548**
OM&A Expenses	644,340	670,607	638,471	744,673	730,565	744,037	716,586	809,404	821,163
Depreciation & Amortization	75,576	113,903	72,025	72,466	50,827	52,874	49,114	154,279	120,706
Property and Taxes	13,150	9,885	7,123	7,050	6,619	6,989	7,916	8,100	8,262
Total Costs & Expenses	**733,066**	**794,394**	**717,619**	**824,189**	**788,011**	**803,900**	**773,615**	**971,783**	**950,131**
Deemed Interest Expenses	38,606	19,759	7,170	6,037	4,490	2,425	4,020	4,020	42,390
Total Expenses	**771,672**	**814,153**	**724,789**	**830,227**	**792,501**	**806,326**	**777,635**	**975,803**	**992,521**
Utility Income before Income Taxes / PILs	**68,982**	**-86,209**	**150,769**	**148,485**	**35,866**	**25,939**	**29,262**	**-98,332**	**63,028**
PILs / Income Taxes	13,814	0	0	0	0	1,902	4,126	0	0
Utility Income	**55,168**	**-86,209**	**150,769**	**148,485**	**35,866**	**24,037**	**25,136**	**-98,332**	**63,028**
	Profit	***Loss***	***Profit***	***Profit***	***Profit***	***Profit***	***Profit***	***Loss***	***Profit***

RATE BASE AND REVENUE DEFICIENCY

As shown in the following table, CPUC's revenue deficiency has steadily grown indicating that it is time for the utility to re-establish its rates based on its costs. The revenue deficiency which has been growing over time as a result of the new corporate structure, the addition of a new management position and inflationary increases indicate that the utility should. This is an indication that the utility's costs have exceeded its revenues and as such better aligned rates are needed.

The revenue sufficiency for 2012, 2013, 2014 and 2015 was -$151,938, $57,533, $51,031, $53,322 -$63,391respectively. CPUC expects a deficit of -$206,479 in 2018 and its deficiency to be eliminated in 2019 with the approval of new rates.

Table 25 - Table of Rate Base and Revenue Deficiency

	Board Approved	Actual	Actual	Actual	Actual	Actual	Actual	Projected	Projected
	2012	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Utility Income	**55,168**	**86,209**	**-156,931**	**-148,485**	**-35,866**	**-24,037**	**-25,136**	**-98,332**	**63,028**
Gross Fixed Assets (year end)	2,554,525	2,562,037	2,650,263	2,694,186	2,795,361	2,831,645	2,861,812	3,884,684	3,965,351
			88,227	43,923	101,175	36,284	30,167	1,028,972	80,667
Accum Depreciation	-1,517,843	-1,478,772	-1,550,797	-1,623,263	-1,674,089	-1,726,964	-1,776,077	-2,378,056	-2,498,762
Net Fixed Assets	1,036,682	1,092,839	1,099,466	1,070,923	1,037,247	1,104,681	1,085,734	1,506,628	1,466,589
Average Net Fixed Assets	1,036,682	909,192	1,096,153	1,085,195	1,054,085	1,070,964	1,095,208	1,296,181	1,486,609
								1,805,851	*1,750,767*
Utility Rate Base	1,512,283	1,378,657	1,619,245	1,724,094	1,632,050	1,673,119	1,603,996	1,808,901	1,750,767
Deemed Equity Portion of Rate Base	604,913	551,463	647,698	689,638	652,820	669,248	641,598	723,560	700,307
Income/(Equity Portion of Rate Base)	9.12%	6.25%	-9.69%	-8.61%	-2.20%	-1.44%	-1.57%	-5.44%	3.60%
Indicated Rate of Return	6.20%	-4.82%	9.75%	9.16%	9.47%	2.41%	2.49%	-5.21%	6.02%
Approved Rate of Return	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.02%
Sufficiency / (Deficiency) in Return	0.00%	(11.02%)	3.55%	2.96%	3.27%	(3.79%)	(3.71%)	(11.41%)	0.00%
Equity	*40%*	*40%*	*40%*	*40%*	*40%*	*40%*	*40%*	*40%*	*40%*
Short Term Debt	*4%*	*4%*	*4%*	*4%*	*4%*	*4%*	*4%*	*4%*	*4%*
Long Term Debt	*56%*	*56%*	*56%*	*56%*	*56%*	*56%*	*56%*	*56%*	*56%*
Equity Return	*9.12%*	*9.12%*	*9.12%*	*9.12%*	*9.12%*	*9.12%*	*9.12%*	*9.12%*	*9.00%*
Short Debt Return	*2.08%*	*2.08%*	*2.08%*	*2.08%*	*2.08%*	*2.08%*	*2.08%*	*2.08%*	*2.29%*
Long Debt Return	*4.41%*	*4.41%*	*4.41%*	*4.41%*	*4.41%*	*4.41%*	*4.41%*	*4.41%*	*4.16%*
Tax Rate	*15.50%*	*15.50%*	*15.50%*	*15.50%*	*15.50%*	*15.50%*	*15.50%*	*15.50%*	*15.50%*
Net Revenue Sufficiency / (Deficiency)	**0**	**-151,938**	**57,533**	**51,031**	**53,322**	**-63,391**	**-59,575**	**-206,479**	**0**
		deficiency	***Sufficiency***	***Sufficiency***	***Sufficiency***	***Deficiency***	***Deficiency***	***Deficiency***	

CPUC strives to be financially responsible in controlling capital and OM&A expenditures to provide a rate of return within the OEB allowed a return on equity is thereby meeting the shareholder's expectations while continuing to reinvest in its distribution system to meet customer expectations and operational efficiencies for the safe and reliable delivery of electricity.

1.10.1 HISTORICAL FINANCIAL STATEMENTS

The following attachments are presented in this next section. [55]

- ✓ Appendix A Year ended 31 December 2013 (compared to 2012)
- ✓ Appendix B Year ended 31 December 2015 (compared to 2014)
- ✓ Appendix C Year ended 31 December 2017 (compared to 2016)

1.10.2 RECONCILIATION BETWEEN FINANCIAL STATEMENTS AND RESULTS FIELD[56]

A detailed reconciliation between the financial results shown in CPUC's RRR filings, Audited Financial Statements and with the regulatory financial results filed in the application is presented in Appendix A-C of this Exhibit. All variances are as a result of the audit of account 1595 which still ongoing as at the time of the filing.

[55] MFR - Non-consolidated Audited Financial Statements for 2 most recent years (i.e. 3 years of historical actuals)
[56] MFR - Detailed reconciliation of AFS with regulatory financial results filed in the application, with identification of any deviations that are being proposed

1.10.3 ANNUAL REPORT

CPUC does not publish an annual report to its shareholders. [57]

1.10.4 PROSPECTUS AND RECENT DEBT/SHARE ISSUANCE UPDATE

CPUC does not issue debt or share nor do they publish any prospectus.[58]

1.10.5 OTHER RELEVANT INFORMATION

Distributor Consolidation

CPUC has not nor is currently contemplating selling its utility or amalgamating with other utilities and as such, no savings are identified in this application . [59][60]

CPUC has never applied or been approved for and ICM/ACM. [61]

The utility does not have any additional or relevant information other than what is being filed in this application.

[57] MFR - Annual Report and MD&A for most recent year of distributor and parent company, if applicable
[58] MFR - Rating Agency Reports, if available; Prospectuses, etc. for recent and planned public issuances
[59] MFR - If a distributor has acquired or amalgamated with another distributor, identify any incentives that formed part of the acquisition or amalgamation transaction if the incentive represents costs that are being proposed to remain or enter rate base and/or revenue requirement.
[60] MFR - Description of actual savings as a result of consolidation compared to what was in the approved consolidation application and explanation of how savings are sustainable and the efficacy of any rate plan approved as part of the MAADs application
[61] MFR - Identify approved ACM or ICM from a previous Price Cap IR application it proposes be incorporated into rate base.

APPENDICES

Appendix A	Financial Statements 2012 / 2013
Appendix B	Financial Statements 2014 / 2015
Appendix C	Financial Statements 2016 / 2017
Appendix D	Reconciliation for RRR to FS
Appendix E	Survey Results
Appendix F	Newsletter
Appendix G	PDF of List of Approvals
Appendix H	Map of Service Area
Appendix I	Community Profile
Appendix J	Facebook Comments
Appendix K	PowerPoint Presentation
Appendix L	Customer Outreach and Communication Plan

Appendix A Financial Statements 2012 / 2013

Financial Statements of

CHAPLEAU PUBLIC UTILITIES CORPORATION

Year ended December 31, 2013

KPMG LLP
Chartered Accountants
Claridge Executive Centre
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INDEPENDENT AUDITORS' REPORT

To the Shareholder of Chapleau Public Utilities Corporation

We have audited the accompanying financial statements of **Chapleau Public Utilities Corporation**, which comprise the balance sheet as at December 31, 2013 and the statements of income and comprehensive income and deficit 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 the Chapleau Public Utilities Corporation 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

April 8, 2014
Sudbury, Canada

CHAPLEAU PUBLIC UTILITIES CORPORATION

Balance Sheet

December 31, 2013, with comparative information for 2012

	2013	2012
Assets		
Current assets:		
Cash	$ 56,652	$ 50,903
Short-term investments	249,240	249,230
Trade receivables (note 2)	67,386	81,366
Plant materials and supplies	53,669	55,429
Prepaid expenses	9,923	9,575
Unbilled revenue - energy sales	569,669	484,422
Unbilled revenue - distribution	56,302	44,572
Advances to related company (note 3)	54,954	2,391
	1,117,795	977,888
Property, plant and equipment (note 4)	2,650,263	2,562,037
Less accumulated amortization	1,550,797	1,478,772
	1,099,466	1,083,265
Regulatory assets (note 5)	229,386	325,861
	$ 2,446,647	$ 2,387,014
Liabilities and Shareholder's Equity		
Current liabilities:		
Accounts payable and accrued liabilities (note 6)	$ 442,524	$ 390,906
Other liabilities:		
Regulatory liabilities (note 5)	125,498	275,564
Customer deposits	27,904	26,754
	153,402	302,318
	595,926	693,224
Shareholder's equity:		
Share capital (note 8)	2,243,058	2,243,058
Deficit	(392,337)	(549,268)
	1,850,721	1,693,790
Contingency (note 11)		
Commitment (note 15)		
	$ 2,446,647	$ 2,387,014

See accompanying notes to financial statements.

On behalf of the Board:

______________________________ Director

CHAPLEAU PUBLIC UTILITIES CORPORATION

Statement of Income and Comprehensive Income and Deficit

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

	2013	2012
Revenue:		
Energy sales (note 13)	$ 2,835,527	$ 2,449,277
Distribution services	847,249	691,158
	3,682,776	3,140,435
Expenses:		
Power purchased (note 13)	2,835,527	2,449,277
Operations and maintenance	321,772	293,337
Administration and general	206,736	199,502
Billing and collection	115,086	185,653
Amortization of property, plant and equipment	72,025	113,903
	3,551,146	3,241,672
Income (loss) before the undernoted	131,630	(101,237)
Other income (expenses):		
Interest earned	8,952	14,509
Donations	(2,000)	(2,000)
Late payment charges	7,192	5,624
Miscellaneous	18,327	16,653
Other interest	(7,170)	(19,759)
	25,301	15,027
Net income (loss) and comprehensive income (loss)	156,931	(86,210)
Deficit, beginning of year	(549,268)	(463,058)
Deficit, end of year	$ (392,337)	$ (549,268)

See accompanying notes to financial statements.

CHAPLEAU PUBLIC UTILITIES CORPORATION

Statement of Cash Flows

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

	2013	2012
Cash provided by (used in):		
Operating activities:		
Net income (loss) and comprehensive income (loss)	$ 156,931	$ (86,210)
Item not involving cash:		
Amortization of property, plant and equipment	72,025	113,903
	228,956	27,693
Change in non-cash operating working capital:		
Decrease (increase) in trade receivables	13,980	(25,149)
Decrease (increase) in plant materials and supplies	1,760	(15,268)
Increase in prepaid expenses	(348)	(1,593)
Decrease (increase) in unbilled revenue - energy sales	(85,247)	25,242
Decrease (increase) in unbilled revenue - distribution	(11,730)	1,328
Increase in accounts payable and accrued liabilities	51,618	19,417
Increase in customer deposits	1,150	2,235
	200,139	33,905
Financing activities:		
Decrease in advances from related company	(51,388)	(29,571)
Investing activities:		
Increase short-term investments	(10)	(1,078)
Purchase of property, plant and equipment	(88,226)	(23,456)
Decrease (increase) in regulatory liabilities and assets	(54,766)	35,480
	(143,002)	10,946
Increase in cash position	5,749	15,280
Cash position, beginning of year	50,903	35,623
Cash position, end of year	$ 56,652	$ 50,903
Significant non-cash transactions:		
Approval for the recovery of smart meter capital costs (note 15)	$ -	$ 438,593

See accompanying notes to financial statements.

Chapleau Public Utilities Corporation (the "Corporation") was incorporated August 18, 1999 to operate as an electricity distribution company.

1. Significant accounting policies:

The financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles ("GAAP") including accounting principles prescribed by the Ontario Energy Board (the "OEB") in the Accounting Procedures Handbook (the "AP Handbook") for Electric Distribution Utilities, and reflect the significant accounting policies as summarized below:

(a) Change in accounting policies:

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 Corporation elected to take the optional deferral of its adoption of IFRS; therefore, it continues to prepare its financial statements in accordance with Canadian GAAP accounting standards in Part V of the CPA Canada Handbook - Accounting.

(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 fulfil 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 ("GAAP") for enterprises operating in a non-rate regulated environment.

1. Significant accounting policies (continued):

(b) Regulation (continued):

The following regulatory treatments have resulted in accounting treatments that differ from 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 or limitations of increase in revenues associated with amounts that are expected to refunded to customers through the rate-making process.

ii) Payment in lieu of corporate income taxes and capital taxes:

The current tax-exempt status of the Corporation under the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) reflects the fact that the Corporation is wholly owned by municipalities. This tax-exempt status might be lost in a number of circumstances, including if the municipality ceases to own 90% or more of the shares or capital of the Corporation, or if a non-government entity has rights immediately or in the future, either absolutely or contingently, to acquire more than 10% of the shares of the Corporation.

Commencing October 1, 2001, the Corporation is required, under the Electricity Act 1998, to make payments-in-lieu of corporate income taxes (“PILs”) to Ontario Electricity Financial Corporation, which will be used to repay the stranded debt incurred by the former Ontario Hydro. 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.

As a result of becoming subject to PILs, the Corporation’s taxation year was deemed to have ended immediately beforehand and a new taxation year was deemed to have commenced immediately thereafter. The Corporation was therefore deemed to have disposed of each of its assets at their then fair market value and to have reacquired such assets at that same amount for purposes of computing its future income subject to PILs. For purposes of certain provisions, the Corporation was deemed to have a new company and, as a result, tax credits or tax losses not previously utilized by the Corporation would not be available to it after the change in tax status. Essentially, the Corporation was taxed as though it had a “fresh start” at the time of its change in tax status.

1. Significant accounting policies (continued):

(c) Revenue recognition and power purchased:

Revenue is recorded in the accounts to various dates on the basis of monthly or bi-monthly meter readings. At the end of an accounting cycle, there is energy used by consumers for which meter readings are not available. The unbilled revenue is estimated and recorded in the accounts at the end of each fiscal year. The related cost of energy is recorded on the basis of energy used.

(d) Plant materials and supplies:

Inventories consist of parts, supplies and materials held for future capital expansion. Inventories are valued at the lower of cost and net realizable value, and items considered major spare parts are recorded as capital assets. Inventory write-downs are reversed if the circumstances resulting in the original write-down have reversed.

(e) Property, plant and equipment:

Property, plant and equipment are recorded at cost. Amortization is charged to operations using the following methods and annual rates:

Asset	Basis	2013 Rate	2012 Rate
Computer equipment and software	Declining-balance	55%	55%
Meters	Declining-balance	5 - 6.67%	10%
Transmission and distribution systems	Declining-balance	2%	4%

Amortization is taken at 50% of the above rate in the year of acquisition.

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):

(f) Asset retirement obligations:

The Corporation 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 Corporation 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 Corporation's transmission and distribution assets may have asset retirement obligations. As the Corporation 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 Corporation is legally required to remove, an asset retirement obligation will be recognized at that time.

(g) Use of estimates:

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the year. Actual results could differ from those estimates including changes as a result of future decisions made by the OEB, Minister of Energy or the Minister of Finance.

(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 the Corporation.

1. Significant accounting policies (continued):

(i) Pension plan:

The Corporation provides a pension plan for its employees through the Ontario Municipal Employees Retirement System (“OMERS”). OMERS is a multi-employer pension plan, which operates as the Ontario Municipal Employees Retirement Fund (the “Fund”) and provides pensions for employees of Ontario municipalities, local boards, public utilities, and school boards. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund. The Corporation recognizes the expense related to this plan as contributions are made.

(j) Financial instruments - recognition and measurement - Section 3855:

This Section establishes the standards for the recognition and measurement of financial assets and financial liabilities. At inception, all financial instruments which meet the definition of a financial asset or financial liability are to be recorded at fair value, unless fair value cannot be reliably determined. Depending on the nature of the financial instrument, revenues, expenses, gains and losses would be reported in either net income or other comprehensive income. Subsequent measurement of each financial instrument will depend on the balance sheet classification elected by the Corporation. The Corporation has elected the following balance sheet classifications with respect to its financial assets and financial liabilities:

- Cash is classified as “Assets Held-for-Trading” and is measured at fair value.

- Investments are classified as “Held-to-Maturity Investments” and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value.

- Accounts receivable are classified as “Loans and Receivables” and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method.

- Accounts payable and accrued liabilities and the long-term debt are classified as “Other Financial Liabilities” and are initially measured at their fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method.

1. Significant accounting policies (continued):

(k) Comprehensive income:

Section 1530 describes the recognition and disclosure requirements with respect to comprehensive income. Comprehensive income consists of net income and other comprehensive income. Other comprehensive income represents the changes in the fair value of a financial instrument which have not been included in net income.

The Corporation had no adjustments to other comprehensive income during the year ending December 31, 2013.

(j) Change in estimates:

Effective January 1, 2013, the Corporation 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(e). The impact of the change in 2013 was a reduction of amortization expense of approximately $24,413. Further, in accordance with OEB accounting requirements, an offsetting reduction of $24,413 has been recorded against distribution revenue and an increase to regulatory liabilities. As a result, the impact on net income before PILs is nil.

2. Trade receivables:

	2013	2012
Electrical	$ 84,036	$ 95,119
Provision for doubtful accounts	(16,650)	(13,753)
	$ 67,386	$ 81,366

3. Advances from related company:

The amounts advanced from related company are non-interest bearing, unsecured and will be paid within the next twelve months. The Corporation is related by virtue of common ownership.

4. Property, plant and equipment:

			2013	2012
	Cost	Accumulated amortization	Net book value	Net book value
Land	$ 141	$ -	$ 141	$ 141
Computer equipment and software	109,323	61,402	47,921	42,047
Meters	411,207	19,593	391,614	391,245
Transmission and distribution systems	2,129,592	1,469,802	659,790	649,832
	$ 2,650,263	$ 1,550,797	$ 1,099,466	$ 1,083,265

5. Regulatory assets and liabilities:

		2013		2012
(i) Regulatory assets consist of the following:				
Long-term portion of regulatory assets:				
Smart meter funding and cost recovery	$	39,419	$	52,585
Retail settlement variance - power charges		-		229,444
Recovery of regulatory asset balance - principal		30,747		-
Retail settlement variance - connection charges		1,079		2,324
Retail settlement variance - network charges		10,681		3,953
IFRS transition and carrying costs		5,904		4,697
Retail settlement variance - retail services		2,560		1,759
Recovery of regulatory asset balance - global adjustment		111,813		862
Ontario clean energy		12,663		24,149
Retail settlement variance - low voltage charges		7,220		-
HST / OVAT		5,386		6,088
SME variance		1,914		-
Total regulatory assets	$	229,386	$	325,861
(ii) Regulatory liabilities consist of the following:				
Current portion of regulatory liabilities:				
Long-term portion of regulatory liabilities:				
Retail settlement variance - wholesale market charge		63,889		56,275
Recovery of regulatory liability balance - interest		13,663		37,640
Retail settlement variance - low voltage charges		-		31,254
Recovery of regulatory liability balance - principal		24,412		150,395
Retail settlement variance - power charges		14,832		-
Lost revenue adjustment mechanism		8,702		-
		125,498		275,564
Total regulatory liabilities	$	125,498	$	275,564

6. Accounts payable and accrued liabilities:

		2013		2012
Independent Electricity System Operator	$	361,921	$	284,602
Miscellaneous		80,603		106,304
	$	442,524	$	390,906

7. Bank borrowing facilities:

The Corporation has a line of credit in the amount of $200,000 available, bearing interest at prime plus 1%. At December 31, 2013, no amount has been drawn on this line of credit (2012 - $Nil).

8. Share capital:

	2013	2012
Authorized:		
Unlimited class B special shares		
Unlimited common shares		
Issued:		
1,121,529 class B special shares	$ 1,121,529	$ 1,121,529
1,121,529 common shares	1,121,529	1,121,529
	$ 2,243,058	$ 2,243,058

9. Payment in lieu of taxes:

For payment in lieu of tax purposes, the Corporation has losses of $189,214 (2012 - $418,138) carried forward which can be applied to reduce future years' taxable income. The benefit of these loss carryforwards have not been reflected in the financial statements These losses will expire as follows:

2015	$ 174,811
2032	14,403

10. Related party transactions:

The Corporation is related to the Township by virtue of the fact that the Township is the sole shareholder of the Corporation. The Corporation is related to Chapleau Energy Services Corporation by virtue of common ownership.

During the year, the Corporation billed the Township $386,883 (2012 - $356,183) for power purchased.

Also, the Corporation was charged $435,832 (2012 - $416,343) by Chapleau Energy Services Corporation, for the Corporation's portion of certain shared costs.

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.

11. Contingency:

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 the Corporation fails to make a payment required by default notice issued by the IESO. At December 31, 2013, no amounts have been drawn on this letter of credit in the amount of $209,813.

12. Credit risk and financial instruments:

(a) Fair value of financial assets and financial liabilities

The carrying value of cash, short-term investments, trade receivables, unbilled revenue, accounts payable and accrued liabilities, advances from related company and customer deposits approximate their fair value due to the relatively short periods to maturity of these items or because they are receivable or payable on demand.

(b) Credit risk

For distribution retail customers, credit losses are generally low across the sector. The Corporation provides for an allowance for doubtful accounts to absorb credit losses.

At December 31, 2013, there are no significant concentrations of credit risk with respect to any class of financial assets.

(c) Interest rate risk

Cash balances not required to meet day-to-day obligations of the Corporation are invested in Canadian money market instruments, with terms not more than one year or 365 days, exposing the Corporation to fluctuations in short-term interest rates. These fluctuations could affect the level of interest income earned by the Corporation.

13. Electric energy services:

	2013	2012
Revenue:		
Electricity	$ 2,452,747	$ 2,103,735
Transmission services	382,780	345,542
	$ 2,835,527	$ 2,449,277
Costs:		
Electricity	$ 2,452,747	$ 2,103,735
Transmission services	382,780	345,542
	$ 2,835,527	$ 2,449,277

14. General liability insurance:

The Corporation is a member of the Municipal Electric Association Reciprocal Insurance Exchange ("MEARIE"), which is a pooling of general liability insurance risks. Members of MEARIE would be assessed on a pro-rata basis should losses be experienced by MEARIE, for the years in which the Corporation was a member. To December 31, 2013, the Corporation has not been made aware of any additional assessments.

15. Commitment:

In support of the Province of Ontario's decision to install smart meters throughout Ontario by 2010 and pursuant to Ontario Regulation 427/06, the Corporation launched its smart meter initiative in 2009. The Corporation has committed to install 1,253 smart meters and supporting infrastructure by the end of 2010. 1,253 Smart meters or 100% deployment was completed in 2012.

The OEB adopted the policy that specific funding for the capital cost of smart meters should be included in distribution rates by all Ontario electric distribution companies. The Board decided that "seed" funding equivalent to $0.27 per customer per month be included in the Corporation's distribution rates commencing May 1, 2006. This funding was increased to $1.00 per customer per month effective May 1, 2009 pursuant to OEB Decision and Order of March 10, 2009. Revenue has been reduced by the amount funded in rates, and have been deferred and netted against smart metering capital costs incurred in accordance with the AP Handbook. Unfunded costs including financing expense, are expected to be recovered through future distribution rates once the project is completed, pursuant to the Ontario Energy Board's guidelines.

In 2012, following completion of the Smart Meter Initiative, the Corporation applied to the OEB for smart meter cost recovery (EB-2011-0322). The OEB's decision allowed the Corporation to transfer $438,593 million of smart meter assets to its Balance Sheet and to implement rate riders effective December 1, 2012 and April 30, 2016 to recover the costs associated with the smart meters and supporting infrastructure.

16. Corporate income and capital taxes:

	2013	2012
Rate reconciliation:		
Income (loss) from continuing operations before income taxes	$ 156,931	$ (86,210)
Statutory Canadian Federal and Provincial income tax rate	26.5%	26.25%
Expected taxes on income	41,587	(22,630)
Increase (decrease) in income taxes resulting from:		
Loss carry forwards	(41,587)	22,630
Effective tax rate	0%	0%

17. Emerging accounting changes:

International Financial Reporting Standards [“IFRS”]:

On February 13, 2008, the Accounting Standards Board of Canada [“AcSB”] announced that publicly accountable enterprises will be required to change over to IFRS effective January 1, 2011.

The International Accounting Standards Board (“IASB”) has approved 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 entity’s financial position, performance and cash flows.

In February 2013, the AcSB extended the deferral of mandatory transition to IFRS to rate-regulated entities to January 1, 2015. This is the fourth such deferral granted by the AcSB.

Some of the converged standards will be implemented in Canada during the transition period with the remaining standards adopted at the change over date. The Corporation has launched an internal initiative to govern the conversion process and is currently in the process of evaluating the potential impact of the conversion to IFRS on its financial statements.

Appendix B Financial Statements 2014 / 2015

Financial Statements of

CHAPLEAU PUBLIC UTILITIES CORPORATION

Years ended December 31, 2015 and
December 31, 2014

KPMG LLP
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INDEPENDENT AUDITORS' REPORT

To the Shareholder of Chapleau Public Utilities Corporation

We have audited the accompanying financial statements of Chapleau Public Utilities Corporation which comprise the statements of financial position as at December 31, 2015, December 31, 2014 and January 1, 2014, the statements of income and comprehensive income, changes in equity and cash flows for the years ended December 31, 2015 and December 31, 2014, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audits to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Chapleau Public Utilities Corporation as at December 31, 2015, December 31, 2014 and January 1, 2014 and its financial performance and its cash flows for the years ended December 31, 2015 and December 31, 2014 in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

April 14, 2016
Sudbury, Canada

CHAPLEAU PUBLIC UTILITIES CORPORATION

Statements of Financial Position

As at December 31, 2015, December 31, 2014 and January 1, 2014

		December 31, 2015	December 31, 2014	January 1, 2014
Assets				
Current assets:				
Cash and cash equivalents (note 4)	$	313,658	91,805	56,652
Accounts receivable (note 5)		207,348	347,538	67,386
Unbilled revenue		470,042	462,994	625,971
Short-term investments		262,267	254,819	249,240
Inventory (note 6)		50,763	51,704	53,669
Prepaid expenses		5,900	6,554	9,923
Due from related parties (note 18)		81,147	146,914	54,954
Total current assets		1,391,125	1,362,328	1,117,795
Non-current assets:				
Property, plant and equipment (note 7)		1,040,208	1,031,244	1,051,566
Intangible assets (note 8)		81,063	39,679	47,900
Total non-current assets		1,121,271	1,070,923	1,099,466
Total assets		2,512,396	2,433,251	2,217,261
Regulatory deferral account debit balances (note 10)		1,207,050	1,000,389	743,753
Total assets and regulatory deferral account debit balances	$	3,719,446	3,433,640	2,961,014

See accompanying notes to financial statements.

CHAPLEAU PUBLIC UTILITIES CORPORATION

Statements of Financial Position

As at December 31, 2015, December 31, 2014 and January 1, 2014

		December 31, 2015	December 31, 2014	January 1, 2014
Liabilities and Shareholder's Equity				
Current liabilities:				
Accounts payable and accrued liabilities	$	447,972	439,054	442,524
Customer deposits (note 11)		25,054	28,634	27,904
Total liabilities		473,026	467,688	470,428
Shareholder's equity:				
Share capital (note 12)		2,243,058	2,243,058	2,243,058
Deficit		(207,988)	(243,852)	(392,337)
Total shareholder's equity		2,035,070	1,999,206	1,850,721
Commitments and contingences (note 15)				
Total liabilities and shareholder's equity	$	2,508,096	2,466,894	2,321,149
Regulatory deferral account credit balances (note 10)		1,211,350	966,746	639,865
Total equity, liabilities and regulatory deferral account credit balances	$	3,719,446	3,433,640	2,961,014

See accompanying notes to financial statements.

Approved by the Board:

_______________________ Director

_______________________ Director

CHAPLEAU PUBLIC UTILITIES CORPORATION

Statements of Income and Comprehensive Income

Years ended December 31, 2015 and December 31, 2014

		2015	2014
Energy sales	$	3,115,911	3,417,267
Distribution services		784,587	928,309
		3,900,498	4,345,576
Other operating revenue (note 13)		30,138	36,329
Net operating revenue		3,930,636	4,381,905
Expenses:			
Energy purchases		3,096,735	3,444,280
Operations and maintenance		300,290	322,041
General and administrative		300,886	292,074
Billing and collection		129,895	135,609
Depreciation and amortization		50,827	72,466
Other costs		2,000	2,000
		3,880,633	4,268,470
Income from operating activities		50,003	113,435
Other income:			
Finance income (note 14)		13,641	14,074
Finance charges (note 14)		(4,490)	(6,037)
Net finance income		9,151	8,037
Income for the year before movements in regulatory deferral account balances		59,154	121,472
Net movement in regulatory deferral account balances, net of tax		(23,290)	27,013
Income for the year and net movements in regulatory deferral account balances		35,864	148,485
Total comprehensive income for the year	$	35,864	148,485

See accompanying notes to financial statements.

CHAPLEAU PUBLIC UTILITIES CORPORATION

Statements of Changes in Equity

Years ended December 31, 2015 and December 31, 2014

		Share Capital	Deficit	Total
Balance, January 1, 2014	$	2,243,058	(392,337)	2,635,395
Net income		-	148,485	148,485
Balance, December 31, 2014		2,243,058	(243,852)	2,486,910
Net income		-	35,864	35,864
Balance, December 31, 2015	$	2,243,058	(207,988)	2,451,046

See accompanying notes to financial statements.

CHAPLEAU PUBLIC UTILITIES CORPORATION

Statements of Cash Flows

Years ended December 31, 2015 and December 31, 2014

		2015	2014
Cash flows from operating activities:			
Net income and comprehensive income	$	35,864	148,485
Item not involving cash:			
Depreciation and amortization		50,827	72,466
		86,691	220,951
Changes in non-cash working capital:			
Decrease (increase) in trade receivables		140,190	(280,152)
Decrease in plant materials and supplies		941	1,965
Decrease in prepaid expenses		654	3,369
Decrease (increase) in unbilled revenue - energy sales		(7,048)	162,977
Increase (decrease) in accounts payable and accrued liabilities		8,918	(3,470)
Decrease in regulatory deferral account balances		37,943	70,245
Increase (decrease) in customer deposits		(3,580)	730
Net cash from operating activities		264,709	176,615
Cash flows from financing activities:			
Increase (decrease) in advances from related company		65,767	(91,960)
Net cash from financing activities		65,767	(91,960)
Cash flows from investing activities:			
Increase in short-term investments		(7,448)	(5,579)
Purchase of intangible assets		(54,800)	-
Purchase of property, plant and equipment		(46,375)	(43,923)
Net cash from financing activities		(108,623)	(49,502)
		(108,623)	(49,502)
Increase in cash		221,853	35,153
Cash and cash equivalents, beginning of year		91,805	56,652
Cash and cash equivalents, end of year	$	313,658	91,805

See accompanying notes to financial statements.

1. Reporting entity:

Chapleau Public Utilities Corporation (the “Corporation”) is a rate regulated, municipally owned hydro distribution company incorporated under the laws of Ontario, Canada. The Corporation is located in the Township of Chapleau. The address of the Corporation’s registered office is 110 Lorne Street, Chapleau, Ontario.

The Corporation delivers electricity and related energy services to residential and commercial customers in the Township of Chapleau. The Corporation is wholly owned by the Corporation of the Township of Chapleau.

The financial statements are for the Corporation as at and for the year ended December 31, 2015.

2. Basis of presentation:

(a) Statement of compliance:

The Corporation's financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS").

(b) Adoption of IFRS:

These are the Corporation’s first financial statements prepared in accordance with IFRS and IFRS1 *First-time Adoption of International Financial Reporting Standards* has been applied.

The financial statements were approved by the Board of Directors on April 14, 2016.

(c) Basis of measurement:

The financial statements have been prepared on the historical cost basis except for the following:

(i) Where held, financial instruments at fair value through profit or loss, including those held for trading, are measured at fair value.

(ii) Contributed assets are initially measured at fair value.

The methods used to measure fair values are discussed further in note 19.

(d) Functional and presentation currency:

These financial statements are presented in Canadian dollars, which is the Corporation's functional currency. All financial information presented in Canadian dollars has been rounded to the nearest thousand.

2. Basis of presentation (continued):

(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.

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
(ii) Note 15 – Commitments and contingencies

(f) Rate regulation:

The Corporation is regulated by the Ontario Energy Board ("OEB"), under the authority granted by the *Ontario Energy Board Act, 1998*. Among other things, the OEB has the power and responsibility to approve or set rates for the transmission and distribution of electricity, providing continued rate protection for electricity consumers in Ontario, and ensuring that transmission and distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to local distribution companies ("LDCs"), such as the Corporation, which may include, amongst other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes.

The Corporation is required to bill customers for the debt retirement charge set by the province. The Corporation may file to recover uncollected debt retirement charges from Ontario Electricity Financial Corporation ("OEFC") once each year.

Rate setting:

Distribution revenue

For the distribution revenue included in electricity sales, the Corporation files a "Cost of Service" ("COS") rate application with the OEB every five years where rates are determined through a review of the forecasted annual amount of operating and capital expenses, debt and shareholder's equity required to support the Corporation's business. The Corporation estimates electricity usage and the costs to service each customer class to determine the appropriate rates to be charged to each customer class. The COS application is reviewed by the OEB and intervenors and rates are approved based upon this review, including any revisions resulting from that review.

2. Basis of presentation (continued):

(f) Rate regulation (continued):

Electricity revenue

The Corporation last filed a COS application in 2012 for rates effective May 1, 2012 to April 30, 2013. The GDP IPI-FDD for 2015 is 1.6%, the Corporation's productivity factor is 0.0% and the stretch factor is 0.045%, 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 Corporation is billed for the cost of the electricity that its customers use and passes this cost on to the customer at cost without a mark-up.

In the intervening years an Incentive Rate Mechanism application ("IRM") is filed. An IRM application results in a formulaic adjustment to distribution rates that were set under the last COS application. The previous year's rates are adjusted for the annual change in the Gross Domestic Product Implicit Price Inflator for Final Domestic Demand ("GDP IPI-FDD") net of a productivity factor and a "stretch factor" determined by the relative efficiency of an electricity distributor.

As a licensed distributor, the Corporation is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Corporation is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Corporation ultimately collects these amounts from customers.

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 Corporation does not enter into derivative instruments.

Hedge accounting has not been used in the preparation of these financial statements.

Cash equivalents include short-term investments with maturities of three months or less when purchased.

3. Significant accounting policies (continued):

(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.

For customer billings related to electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties, the Corporation has determined that it is acting as a principal for these electricity charges and, therefore, has presented electricity revenue on a gross basis.

Customer billings for debt retirement charges are recorded on a net basis as the Corporation is acting as an agent for this revenue stream.

Rendering of services:

Revenue earned from the provision of services is recognized as the service is rendered.

Government grants:

Incentive payments to which the Corporation 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 Corporation.

(c) Dividends:

Dividends are recognized as revenue when the Corporation has a right to receive the dividend.

(d) Inventory:

Inventory, comprising material and supplies, the majority of which is consumed by the Corporation in the provision of its services, is valued at the lower of cost and net realizable value, with cost being determined on an average cost basis, and includes expenditures incurred in acquiring the 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.

(e) 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 Corporation elected to use the carrying amount as previously determined under Canadian GAAP as the deemed cost at January 1, 2014, the transition date to IFRS.

3. Significant accounting policies (continued):

(e) Property, plant and equipment (continued):

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 Corporation's borrowings. Qualifying assets are considered to be those that take in excess of six months 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 Corporation 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 declining-balance 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.

The estimated useful lives are as follows:

Transmissions and distribution systems	2%
Meters	7%
Computer equipment	20%

Depreciation methods, useful lives, and residual values are reviewed at each reporting date and adjusted prospectively if appropriate.

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3. Significant accounting policies (continued):

(f) Intangible assets:

(i) Computer software:

Computer software that is acquired or developed by the Corporation, including software that is not integral to the functionality of equipment purchased which has finite useful lives, is measured at cost less accumulated amortization and accumulated impairment losses

(ii) Amortization:

Amortization is recognized in profit or loss on a straight-line basis over the estimated useful lives of intangible assets from the date that they are available for use. The estimated useful lives are:

Computer software	5 years

Amortization methods and useful lives of all intangible assets are reviewed at each reporting date and adjusted prospectively if appropriate.

(g) 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.

3. Significant accounting policies (continued):

(g) Impairment (continued):

(ii) Non-financial assets:

The carrying amounts of the Corporation'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.

An impairment loss in respect of goodwill is not reversed. For assets other than goodwill, impairment recognized in prior periods is 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 or amortization, if no impairment loss had been recognized.

(h) Provisions:

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability.

3. Significant accounting policies (continued):

(i) 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 Corporation.

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 assessed 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 is 1.10%.

(j) Employee future benefits:

Pension plan:

The Corporation provides a pension plan for all its full-time employees through Ontario Municipal Employees Retirement System (“OMERS”). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund (“the Fund”), and provides pensions for employees of Ontario municipalities, local boards and public utilities. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund. To the extent that the Fund finds itself in an under-funded position, additional contribution rates may be assessed to participating employers and members.

OMERS is a defined benefit plan. However, as OMERS does not segregate its pension asset and liability information by individual employers, there is insufficient information available to enable the Corporation to directly account for the plan. Consequently, the plan has been accounted for as a defined contribution plan. Obligations for contributions to defined contribution pension plans are recognized as an employee benefit expense in net income when they are due.

3. Significant accounting policies (continued):

(k) Finance income and finance costs:

Finance income is recognized as it accrues in profit or loss, using the effective interest method. Finance income comprises interest earned on cash and cash equivalents and on regulatory assets.

Finance charges comprise interest expense on borrowings and regulatory. Finance costs are recognized as an expense unless they are capitalized as part of the cost of qualifying assets.

(l) Income taxes:

The income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case, it is recognized in equity.

The Corporation is currently exempt from taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act (collectively the "Tax Acts"). Under the *Electricity Act*, 1998, the Corporation makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations. Prior to October 1, 2001, the Corporation was not subject to income or capital taxes. Payments in lieu of taxes are referred to as income taxes.

Current tax is the 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 tax is recognized using the balance sheet method. Under this method, deferred income taxes reflect the net tax effects of temporary differences between the tax basis of assets and liabilities and their 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. Deferred tax 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 tax 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.

4. Cash and cash equivalents:

Cash and cash equivalents consist of overnight deposits at a Canadian chartered bank.

5. Accounts receivable:

	December 31, 2015	December 31, 2014	January 1, 2014
Trade receivables	$ 260,922	$ 389,117	$ 83,474
Billable work	1,270	562	562
Less allowance for doubtful accounts	(54,844)	(42,141)	(16,650)
	$ 207,348	$ 347,538	$ 67,386

6. Inventory:

The amount of inventories consumed by the Corporation and recognized as an expense during 2015 was $941 (2014 - $1,965).

7. Property, plant and equipment:

(a) Cost or deemed cost:

	Land	Transmission and Distribution Systems	Meters	Computer Equipment	Total
Balance at January 1, 2015	$ 141	$ 762,120	$ 308,206	$ 21	$1,070,488
Additions	-	45,854	522	-	46,376
Balance at December 31, 2015	$ 141	$ 807,974	$ 308,728	$ 21	$1,116,864

	Land	Transmission and Distribution Systems	Meters	Computer Equipment	Total
Balance at January 1, 2014	$ 141	$ 743,197	$ 308,206	$ 21	$1,051,565
Additions	–	18,923	–	–	18,923
Balance at December 31, 2014	$ 141	$ 762,120	$ 308,206	$ 21	$1,070,488

7. Property, plant and equipment (continued):

(b) Accumulated depreciation:

	Land	Transmission and Distribution Systems	Meters	Computer Equipment	Total
Balance at January 1, 2015	$ -	$ 17,855	$ 21,379	$ 11	$ 39,245
Depreciation charge	-	18,260	19,149	2	37,411
Balance at December 31, 2015	$ -	$ 36,115	$ 40,528	$ 13	$ 76,656

	Land	Transmission and Distribution Systems	Meters	Computer Equipment	Total
Balance at January 1, 2014	$ –	$ –	$ –	$ –	$ –
Depreciation charge	–	17,855	21,379	11	39,245
Balance at December 31, 2014	$ –	$ 17,855	$ 21,379	$ 11	$ 39,245

(c) Carrying amounts:

	Land	Transmission and Distribution Systems	Meters	Computer Equipment	Total
At December 31, 2015	$ 141	$ 772,064	$ 267,438	$ -	$ 1,040,208
At December 31, 2014	141	744,265	286,827	10	1,031,244
At January 1, 2014	141	743,197	308,206	21	1,051,566

8. Intangible assets:

(a) Cost or deemed cost:

		Computer software
Balance at January 1, 2015	$	72,900
Additions		54,800
Balance at December 31, 2015	$	127,700
Balance at January 1, 2014	$	47,900
Additions		25,000
Balance at December 31, 2014	$	72,900

(b) Accumulated amortization:

		Computer software
Balance at January 1, 2015	$	33,221
Additions in 2015		13,416
Balance at December 31, 2015	$	46,637
Balance at January 1, 2014, restated	$	–
Amortization charges in 2014		33,221
Balance at December 31, 2014	$	33,221

(c) Carrying amounts:

		Computer software
At December 31, 2015	$	81,063
At December 31, 2014	$	39,679
At January 1, 2014	$	47,900

9. Payment in lieu of income taxes:

PIL's varies the amounts which would be computed applying the Corporation's combined statutory tax rate. The following is a reconciliation of the effective tax rate:

	2015	2014
Profit for the period	$ 35,864	$148,485
Income tax using the Corporation's statutory tax rate	9,504	39,349
Change in valuation allowance	(9,504)	(39,349)
	$ –	$ –

The Corporation has non-capital losses of $14,403 (2014 - $40,729) which can be applied to reduce future year's taxable income. The benefit of these losses have not been reflected in these financial statements.

10. 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					
Retail settlement variances	$ 172,237	$ 18,172	$ -	$ 190,409	2
Regulatory variances disposition	683,213	292,216	50,273	925,156	1
Other regulatory accounts	144,939	51,759	105,213	91,485	4
Total amount related to regulatory deferral account debit balances	$ 1,000,389	$ 362,147	$155,486	$1,207,050	

	2014	Balances arising in the period	Recovery/ reversal	2015	Remaining recovery/ reversal period (years)
Regulatory deferral account credit balances					
Retail settlement variances	$ 205,735	$ 76,499	$ -	$ 282,234	2
Regulatory variances disposition	637,095	159,365	977	795,483	1
Other regulatory accounts	123,916	59,903	50,186	133,633	4
Total amount related to regulatory deferral account credit balances	$ 966,746	$ 295,767	$ 51,163	$1,211,350	

10. Regulatory deferral account balance (continued):

Settlement of the retail settlement variance accounts is done on an annual basis through application to the OEB. An application will be made to the OEB to recover the 2014 retail settlement variance accounts. Once approval is received, the approved account balance is moved to the regulatory settlement account. The balance is to be recovered over a period of one to four years.

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 Corporation in accordance with policies set out by the OEB or upon termination of their electricity distribution service.

12. Share capital:

	December 31, 2015	December 31, 2014	January 1, 2014
Authorized:			
Unlimited number of common shares			
Unlimited number of Class B special shares			
Issued:			
1,121,529 common shares	$ 1,121,529	$ 1,121,529	$ 1,121,529
1,121,529 Class B special shares	1,121,529	1,121,529	1,121,529
	$ 2,243,058	$ 2,243,058	$ 2,243,058

13. Other operating revenue:

Other income comprises:

	2015	2014
Rendering of services	$ 23,658	$ 22,662
OPA recoveries	–	6,121
Late payment charges	6,480	7,546
Total other income	$ 30,138	$ 36,329

14. Finance income and expense:

		2015		2014
Interest income on bank deposits	$	13,641	$	14,074
Finance income		13,641		14,074
Interest expense		4,490		6,037
Net finance costs recognized in profit or loss	$	9,151	$	8,037

15. Commitments and contingencies:

General

From time to time, the Corporation is involved in various litigation matters arising in the ordinary course of its business. The Corporation has no reason to believe that the disposition of any such current matter could reasonably be expected to have a materially adverse impact on the Corporation's financial position, results of operations or its ability to carry on any of its business activities.

General Liability Insurance:

The Corporation is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE). MEARIE is a pooling of public liability insurance risks of many of the LDCs in Ontario. All members of the pool are subjected to assessment for losses experienced by the pool for the years in which they were members, on a pro-rata basis based on the total of their respective service revenues. As at December 31, 2015, no assessments have been made.

16. Pension agreement:

The Corporation provides a pension plan for its employees through OMERS. The plan is a multi-employer, contributory defined pension plan with equal contributions by the employer and its employees. In 2015, the Corporation made employer contributions of $26,149 to OMERS (2014 - $28,475).

The Corporation estimates that a contribution of $33,900 to OMERS during the next fiscal year.

17. Employee benefits:

		2015		2014
Salaries, wages and benefits	$	333,577	$	351,308
CPP and EI remittances		14,458		14,485
Contributions to OMERS		26,149		28,475
	$	374,184	$	394,268

18. Related party transactions:

(a) Parent and ultimate controlling party:

The sole shareholder of the Corporation is the Corporation of the Township of Chapleau. Chapleau Public Utilities Corporation is a wholly-owned subsidiary of the Township of Chapleau. The Township produces financial statements that are available for public use.

(b) Entity with common ownership:

The Corporation is related to Chapleau Energy Services by virtue of common ownership.

(c) Key management personnel:

The key management personnel of the Corporation have been defined as members of its board of directors and executive management team members, and is summarized below.

	2015	2014
Directors' fees	$ 13,200	$ 12,200
Salaries and other short-term benefits	159,629	150,027
Post-employment benefits	16,000	15,038
	$ 188,829	$ 177,265

(d) Transactions with entity with common ownership:

In the ordinary course of business, the Corporation has a cost sharing agreement with Chapleau Energy Services. The Corporation was charged $412,494 (2014 - $476,044) by Chapleau Energy Services for the Corporation's portion of certain shared costs.

(e) Transactions with the Township of Chapleau:

The Corporation delivers electricity to the Township throughout the year for the electricity needs of the Township and its related organizations. Electricity delivery charges are at prices and under terms approved by the OEB. The Corporation also provides following services to the Township:

- streetlight maintenance services
- sentinel lights

The Corporation billed the Township $443,310 (2014 - $476,044) for power purchased.

19. 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 Corporation understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Corporation's exposure to a variety of risks such as credit risk, interest rate risk, and liquidity risk, as well as related mitigation strategies are discussed below.

(a) Credit risk:

Financial assets carry credit risk that a counterparty will fail to discharge an obligation which could result in a financial loss. Financial assets held by the Corporation, such as accounts receivable, expose it to credit risk. The Corporation earns its revenue from a broad base of customers located in the Township of Chapleau. No single customer accounts for a balance in excess of 4% 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 $54,845 (2014 - $42,141). An impairment loss of $18,900 (2014 - $29,772) was recognized during the year.

19. Financial instruments and risk management (continued):

(a) Credit risk (continued):

The Corporation's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2015, approximately $44,792 (2014 - $28,947) is considered 60 days past due. The Corporation has over 1,236 customers, the majority of whom are residential. Credit risk is managed through collection of security deposits from customers in accordance with directions provided by the OEB. As at December 31, 2015, the Corporation holds security deposits in the amount of $25,054 (2014 - $28,634).

(b) Market risk:

Market risks primarily refer to the risk of loss resulting from changes in commodity prices, foreign exchange rates, and interest rates. The Corporation currently does not have any material commodity or foreign exchange risk.

(c) Liquidity risk:

The Corporation monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest exposure.

The Corporation is 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 the Corporation fails to make a payment required by default notice issued by the IESO. At December 31, 2015 no amounts have been drawn on this letter of credit in the amount of $209,813.

The majority of accounts payable, as reported on the balance sheet, are due within 30 days.

(d) Capital disclosures:

The main objectives of the Corporation, when managing capital, are to ensure ongoing access to funding to maintain and improve the electricity distribution system, compliance with covenants related to its credit facilities, prudent management of its capital structure with regard for recoveries of financing charges permitted by the OEB on its regulated electricity distribution business, and to deliver the appropriate financial returns.

The Corporation's definition of capital includes shareholder's equity. As at December 31, 2015, shareholder's equity amounts to $2,035,070 (2014 - $1,999,206).

20. Explanation of transition to IFRS:

As stated in note 2(b), these are the Corporation's first financial statements prepared in accordance with IFRS.

The accounting policies set out in note 3 have been applied in preparing the financial statements for the year ended December 31, 2015, the comparative information presented in these financial statements for the year ended December 31, 2014, and in the preparation of an opening IFRS Statement of Financial Position as at January 1, 2014 (the Corporation's date of transition).

In preparing its opening IFRS Statement of Financial Position, the Corporation has adjusted the amounts reported previously in financial statements prepared in accordance with Canadian general accepted accounting principles (CGAAP). An explanation of how the transition from CGAAP to IFRS has affected the Corporation's financial position, financial performance and cash flows is set out in the following table and the notes accompanying the tables.

IFRS 1 Exemptions

IFRS 1 sets out the procedures that the Corporation must follow when it adopts IFRS for the first time as the basis for preparing its financial statements. The Corporation is required to establish its IFRS accounting policies as at December 31, 2015 and, in general, apply these retrospectively to determine the IFRS opening Statement of Financial Position as its date of transition, January 1, 2014. This standard provides a number of mandatory and optional exemptions to this general principle. These are set out below, together with a description in each case of the exemption adopted by the Corporation.

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.

Deemed cost

IFRS 1 provides an optional exemption for a first-time adopted with rate-regulated activities to use the carrying amount of PP & E and intangible assets as deemed cost on transition date when the carrying amount includes costs that do not quality for capitalization in accordance with IFRS. The carrying amount used as deemed cost is $1,051,566. The Corporation elected this exemption and used the carrying amount of the PP & E and intangible assets under CGAPP as deemed cost on transition date.

If an entity applies this exemption, at the date of transition to IFRS, it shall test for impairment each item for which this exemption is used. The assets were tested for impairment at the date of transition and it was determined that the assets were not impaired.

20. Explanation of transition to IFRS (continued):

Reconciliation of statement of financial position and statement of changes in equity

January 1, 2014

Account	Note	CDN GAAP	Presentation Differences	Measurement and Recognition Differences	IFRS
Cash and cash equivalents		$ 56,652	-	-	56,652
Accounts receivable		67,386	-	-	67,386
Unbilled revenue		625,971	-	-	625,971
Short-term investments		249,240	-	-	249,240
Inventory		53,669	-	-	53,669
Prepaid expenses		9,923	-	-	9,923
Due from related parties		54,954	-	-	54,954
Property, plant and equipment		1,099,466	(47,900)	-	1,051,566
Intangible assets		-	47,900	-	47,900
Total assets		2,217,261	-	-	2,217,261
Regulatory deferral account debit balances		229,386	514,367	-	743,753
Total assets and regulatory account debit balances		2,446,647	514,367	-	2,961,014
Accounts payable and accrued liabilities		442,524	-	-	442,524
Customer deposits		27,904	-	-	27,904
Deferred tax liability		-	-	-	-
Total liabilities		470,428	-	-	470,428
Share capital		2,243,058	-	-	2,243,058
Deficit		(392,337)	-	-	(392,337)
Total liabilities and shareholder's equity		2,321,149	-	-	2,321,149
Regulatory deferral account credit-balances		125,498	514,367	-	639,865
Total equity, liabilities and regulatory deferral account credit-balances		$ 2,446,647	-	-	2,961,014

20. Explanation of transition to IFRS (continued):

Reconciliation of statement of financial position and statement of changes in equity

December 31, 2014

Account	Note	CDN GAAP	Presentation Differences	Measurement and Recognition Differences	IFRS
Cash and cash equivalents	$	91,805	-	-	91,805
Accounts receivable		347,538	-	-	347,538
Unbilled revenue		462,994	-	-	462,994
Short-term investments		254,819	-	-	254,819
Inventory		51,704	-	-	51,704
Prepaid expenses		6,554	-	-	6,554
Due from related parties		146,914	-	-	146,914
Property, plant and equipment		1,070,923	(39,679)	-	1,031,244
Intangible assets		-	39,679	-	39,679
Total assets		2,433,251	-	-	2,433,251
Regulatory deferral account debit balances		848,205	-	-	848,205
Total assets and regulatory account debit balances		3,281,456	-	-	3,281,456
Accounts payable and accrued liabilities		439,054	-	-	439,054
Customer deposits		28,634	-	-	28,634
Total liabilities		467,688	-	-	467,688
Share capital		2,243,058	-	-	2,243,058
Deficit		(243,852)	-	-	(243,852)
Total liabilities and shareholder's equity		2,466,894	-	-	2,466,894
Regulatory deferral account credit-balances		814,562	-	-	814,562
Total equity, liabilities and regulatory deferral account credit-balances	$	3,281,456	-	-	3,281,456

20. Explanation of transition to IFRS (continued):

Reconciliation of net income for 2014

Account	Note	CDN GAAP	Presentation Differences	Measurement and Recognition Differences	IFRS
Electricity sales		$ 4,435,915	(90,339)	-	4,345,576
Energy purchases		(3,507,606)	63,326	-	(3,444,280)
Other operating revenue		36,329	-	-	36,329
Operations and maintenance expense		(322,041)	-	-	(322,041)
General and administrative expense		(292,074)	-	-	(292,074)
Billing and collection expense		(135,609)	-	-	(135,609)
Depreciation and amortization		(72,466)	-	-	(72,466)
Other costs		(2,000)	-	-	(2,000)
Finance income		14,074	-	-	14,074
Finance charges		(6,037)	-	-	(6,037)
Net movement in regulartory account deferral balances		-	27,013	-	27,013
Total comprehensive income for the year		$ 148,485	-	-	148,485

Notes to the reconciliations

The impact on deferred tax of the adjustments described below is set out in note (c):

(a) The Corporation has elected under IFRS 1 to use the carrying value of items of PP&E and intangible assets as the deemed cost at the date of transition. Therefore, there has been no change to the net PP&E and intangible assets at January 1, 2014. The effect of this transitional adjustment is a decrease to the original cost and accumulated depreciation of the affected PP&E and intangible assets by $1,490,037 and $60,761 respectively, the CGAAP accumulated depreciation amount, on January 1, 2014.

Explanation of material adjustments to the statement of cash flows for 2014.

There are no material differences between the statement of cash flows presented under IRFSs and the statement of cash flows presented under CGAAP.

Appendix C Financial Statements 2016 / 2017

Financial Statements of

CHAPLEAU PUBLIC UTILITIES CORPORATION

Year ended December 31, 2017

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INDEPENDENT AUDITORS' REPORT

To the Shareholder of Chapleau Public Utilities Corporation

We have audited the accompanying financial statements of Chapleau Public Utilities Corporation which comprise the statement of financial position as at December 31, 2017, the statements of income and comprehensive income, changes in equity and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated 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 Chapleau Public Utilities Corporation as at December 31, 2017, and its financial performance and its cash flows for the year then ended, in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Sudbury, Canada
April 13, 2018

CHAPLEAU PUBLIC UTILITIES CORPORATION

Statement of Financial Position

As at December 31, 2017, with comparative information for 2016

		2017	2016
Assets			
Current assets:			
Cash and cash equivalents (note 4)	$	409,729	303,348
Accounts receivable (note 5)		181,946	246,489
Unbilled revenue		404,526	498,256
Short-term investments		263,272	261,297
Inventory (note 6)		37,889	36,465
Prepaid expenses		6,100	6,000
Due from related parties (note 17)		83,981	63,171
Total current assets		1,387,443	1,415,026
Non-current assets:			
Property, plant and equipment (note 7)		1,027,754	1,039,840
Intangible assets (note 8)		51,880	64,851
Total non-current assets		1,079,634	1,104,691
Total assets		2,467,077	2,519,717
Regulatory deferral account debit balances (note 10)		1,352,488	1,287,797
Total assets and regulatory deferral account debit balances	$	3,819,565	3,807,514

See accompanying notes to financial statements.

CHAPLEAU PUBLIC UTILITIES CORPORATION

Statement of Financial Position (continued)

As at December 31, 2017, with comparative information for 2016

		2017	2016
Liabilities and Shareholder's Equity			
Current liabilities:			
Accounts payable and accrued liabilities	$	491,264	466,925
Payment in lieu of taxes (note 9)		4,126	1,902
Customer deposits (note 11)		20,584	27,979
Total liabilities		515,974	496,806
Shareholder's equity:			
Share capital (note 12)		2,243,058	2,243,058
Deficit		(158,818)	(183,954)
Total shareholder's equity		2,084,240	2,059,104
Total liabilities and shareholder's equity		2,600,214	2,555,910
Regulatory deferral account credit balances (note 10)		1,219,351	1,251,604
Commitments and contingences (note 14)			
Subsequent event (note 19)			
Total equity, liabilities and regulatory deferral account credit balances	$	3,819,565	3,807,514

See accompanying notes to financial statements.

Approved by the Board:

____________________________ Director

____________________________ Director

CHAPLEAU PUBLIC UTILITIES CORPORATION

Statement of Income and Comprehensive Income

Year ended December 31, 2017, with comparative information for 2016

	2017	2016
Energy sales	$ 2,667,417	3,263,340
Distribution services	769,956	784,830
	3,437,373	4,048,170
Other operating revenue (note 13)	27,628	43,782
Net operating revenue	3,465,001	4,091,952
Expenses:		
Energy purchases	2,697,631	3,231,301
Operations and maintenance	352,656	341,725
General and administrative	248,625	286,144
Billing and collection	121,220	121,158
Depreciation and amortization	49,114	52,874
Other costs	2,000	2,000
	3,471,246	4,035,202
Income from operating activities	(6,245)	56,750
Other income:		
Finance income	9,313	3,650
Finance charges	(4,020)	(2,425)
Net finance income	5,293	1,225
Income (loss) for the year before taxes and regulatory items	(952)	57,975
Payment in lieu of taxes (note 9)	4,126	1,902
Net income (loss)	(5,078)	56,073
Net movement in regulatory deferral account balances, net of tax	30,214	(32,039)
Net income and comprehensive income for the year	$ 25,136	24,034

See accompanying notes to financial statements.

CHAPLEAU PUBLIC UTILITIES CORPORATION

Statement of Changes in Equity

Year ended December 31, 2017, with comparative information for 2016

		Share Capital	Deficit	Total
Balance, January 1, 2016	$	2,243,058	(207,988)	2,035,070
Net income and comprehensive income		-	24,034	24,034
Balance, December 31, 2016		2,243,058	(183,954)	2,059,104
Net income and comprehensive income		-	25,136	25,136
Balance, December 31, 2017	$	2,243,058	(158,818)	2,084,240

See accompanying notes to financial statements.

CHAPLEAU PUBLIC UTILITIES CORPORATION

Statement of Cash Flows

Year ended December 31, 2017, with comparative information for 2016

		2017	2016
Cash flows from operating activities:			
Net income and comprehensive income	$	25,136	24,034
Item not involving cash:			
Depreciation and amortization		49,114	52,874
		74,250	76,908
Changes in non-cash working capital:			
Decrease (increase) in trade receivables		64,543	(39,141)
Decrease (increase) in plant materials and supplies		(1,424)	14,298
Increase in prepaid expenses		(100)	(100)
Decrease (increase) in unbilled revenue - energy sales		93,730	(28,214)
Decrease (increase) in accounts payable and accrued liabilities		24,339	18,952
Increase in payment in lieu of taxes		-	1,902
Increase in regulatory deferral account balances		(96,944)	(40,493)
Increase (decrease) in customer deposits		(7,395)	2,925
Net cash from operating activities		150,999	7,037
Cash flows from financing activities:			
Increase in advances from related company		(20,810)	17,976
Cash flows from investing activities:			
Decrease (increase) in short-term investments		(1,975)	970
Purchase of property, plant and equipment		(24,057)	(36,293)
		(26,032)	(35,323)
Increase (decrease) in cash		104,157	(10,310)
Cash and cash equivalents, beginning of year		303,348	313,658
Cash and cash equivalents, end of year	$	407,505	303,348

See accompanying notes to financial statements.

1. Reporting entity:

Chapleau Public Utilities Corporation (the “Corporation”) is a rate regulated, municipally owned hydro distribution company incorporated under the laws of Ontario, Canada. The Corporation is located in the Township of Chapleau. The address of the Corporation’s registered office is 110 Lorne Street, Chapleau, Ontario.

The Corporation delivers electricity and related energy services to residential and commercial customers in the Township of Chapleau. The Corporation is wholly owned by the Corporation of the Township of Chapleau.

The financial statements are for the Corporation as at and for the year ended December 31, 2017.

2. Basis of presentation:

(a) Statement of compliance:

The Corporation's financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS").

The financial statements were approved by the Board of Directors on April 13, 2018.

(b) Basis of measurement:

The financial statements have been prepared on the historical cost basis except for the following:

(i) Where held, financial instruments designated to be measured at fair value through profit or loss, including those held for trading, are measured at fair value.

(ii) Contributed assets are initially measured at fair value.

The methods used to measure fair values are discussed further in note 18.

(c) Functional and presentation currency:

These financial statements are presented in Canadian dollars, which is the Corporation's functional currency. All financial information presented in Canadian dollars.

2. Basis of presentation (continued):

(d) 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.

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
(ii) Note 14 – Commitments and contingencies

(e) Rate regulation:

The Corporation is regulated by the Ontario Energy Board (“OEB”), under the authority granted by the *Ontario Energy Board Act, 1998*. Among other things, the OEB has the power and responsibility to approve or set rates for the transmission and distribution of electricity, providing continued rate protection for electricity consumers in Ontario, and ensuring that transmission and distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to local distribution companies (“LDCs”), such as the Corporation, which may include, amongst other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes.

The Corporation is required to bill customers for the debt retirement charge set by the province. The Corporation may file to recover uncollected debt retirement charges from Ontario Electricity Financial Corporation (“OEFC”) once each year.

Rate setting:

Distribution revenue

For the distribution revenue, the Corporation files a “Cost of Service” (“COS”) rate application with the OEB every five years where rates are determined through a review of the forecasted annual amount of operating and capital expenses, debt and shareholder’s equity required to support the Corporation’s business. The Corporation estimates electricity usage and the costs to service each customer class to determine the appropriate rates to be charged to each customer class. The COS application is reviewed by the OEB and intervenors and rates are approved based upon this review, including any revisions resulting from that review.

2. Basis of presentation (continued):

(e) Rate regulation (continued):

Electricity revenue

The Corporation filed an IRM in October 2014 for rates effective May 1, 2015. The GDP IPI-FDD for 2016 is 1.6%, the Corporation's productivity factor is 0.0% and the stretch factor is 0.045%, 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 Corporation is billed for the cost of the electricity that its customers use and passes this cost on to the customer at cost without a mark-up.

In the intervening years an Incentive Rate Mechanism application ("IRM") is filed. An IRM application results in a formulaic adjustment to distribution rates that were set under the last COS application. The previous year's rates are adjusted for the annual change in the Gross Domestic Product Implicit Price Inflator for Final Domestic Demand ("GDP IPI-FDD") net of a productivity factor and a "stretch factor" determined by the relative efficiency of an electricity distributor.

As a licensed distributor, the Corporation is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Corporation is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Corporation ultimately collects these amounts from customers.

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 Corporation does not enter into derivative instruments.

Hedge accounting has not been used in the preparation of these financial statements.

Cash equivalents include short-term investments with maturities of three months or less when purchased.

3. Significant accounting policies (continued):

(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.

For customer billings related to electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties, the Corporation has determined that it is acting as a principal for these electricity charges and, therefore, has presented electricity revenue on a gross basis.

Customer billings for debt retirement charges are recorded on a net basis as the Corporation is acting as an agent for this revenue stream.

Rendering of services:

Revenue earned from the provision of services is recognized as the service is rendered.

Government grants:

Incentive payments to which the Corporation 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 Corporation.

(c) Dividends:

Dividends are recognized as revenue when the Corporation has a right to receive the dividend and are included within finance income.

(d) Inventory:

Inventory, comprising material and supplies, the majority of which is consumed by the Corporation in the provision of its services, is valued at the lower of cost and net realizable value, with cost being determined on an average cost basis, and includes expenditures incurred in acquiring the 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.

(e) Property, plant and equipment:

All items of property, plant and equipment are measured at cost, or, where the item is transferred from customers, its fair value, less accumulated depreciation.

3. Significant accounting policies (continued):

(e) Property, plant and equipment (continued):

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 Corporation's borrowings. Qualifying assets are considered to be those that take in excess of six months 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 property, plant and equipment are determined by comparing the proceeds from disposal, if any, with the carrying amount of the item of property, plant and equipment and, with the gain or loss recognized within other income in profit or loss.

Major spare parts and standby equipment are recognized as items of property, plant and equipment.

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 Corporation 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 other income. 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 declining-balance 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.

The estimated useful lives are as follows:

Transmission and distribution systems	2%
Meters	7%

Depreciation methods, useful lives, and residual values are reviewed at each reporting date and adjusted prospectively if appropriate.

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3. Significant accounting policies (continued):

(f) Intangible assets:

(i) Computer software:

Computer software that is acquired or developed by the Corporation, including software that is not integral to the functionality of equipment purchased which has finite useful lives, is measured at cost less accumulated amortization and accumulated impairment losses

(ii) Amortization:

Amortization is recognized in profit or loss on a straight-line basis over the estimated useful lives of intangible assets from the date that they are available for use. The estimated useful lives are:

Computer software	5 years

Amortization methods and useful lives of all intangible assets are reviewed at each reporting date and adjusted prospectively if appropriate.

(g) 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.

3. Significant accounting policies (continued):

(g) Impairment (continued):

(ii) Non-financial assets:

The carrying amounts of the Corporation's non-financial assets, other than inventories 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.

An impairment loss in respect of goodwill is not reversed. For assets other than goodwill, impairment recognized in prior periods is 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 or amortization, if no impairment loss had been recognized.

(h) Provisions:

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability.

3. Significant accounting policies (continued):

(i) Regulatory deferral accounts:

In January 2014, the IASB issued IFRS 14 as an interim standard giving entities conducting rate-regulated activities the option of continuing to recognize regulatory balances according to their previous GAAP. Regulatory balances provide useful information about the Corporation's financial position, financial performance and cash flows. IFRS 14 will remain in force until either repealed or replaced by permanent guidance on rate-regulated accounting from the IASB. The Corporation early adopted IFRS 14 in 2015.

The Corporation has determined that certain asset and liability balances arising from rate-regulated activities qualify for the application of regulatory accounting treatment in accordance with IFRS 14 and the accounting principles prescribed by the OEB in the Accounting Procedures Handbook for Electricity Distributors. Under rate-regulated accounting, the timing and recognition of certain expenses and revenues may differ from those otherwise expected under other IFRS in order to appropriately reflect the economic impact of regulatory decisions regarding the Corporation's regulated revenues and expenditures. These amounts arising from timing differences are recorded as regulatory asset and liability balances on the Corporation's consolidated balance sheets, and represent existing rights and obligations regarding cash flows expected to be recovered from or refunded to customers, based on decisions and approvals by the OEB.

Regulatory deferral account asset 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 liability balances represent amounts billed to the customer at OEB approved rates in excess of costs incurred by the Corporation.

Regulatory deferral account asset 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 asset 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 liability balances are recognized if it is probable that future billings in an amount at least equal to the liability balance will be reduced as a result of rate-making activities. The offsetting amount is recognized in profit and loss. The liability 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 liability balance.

The probability of recovery or repayment of the regulatory account balances is assessed 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.

3. **Significant accounting policies (continued):**

(i) Regulatory deferral accounts (continued):

Regulatory deferral accounts attract interest at OEB prescribed rates. In 2016, the interest rate was 1.10%. Regulatory balances can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment or if future OEB direction is determined by management to be probable. In the event that the disposition of these balances is assessed to no longer be probable based on management's judgment, the balances are recorded in the Corporation's statement of income in the period when the assessment is made. Regulatory balances that do not meet the definition of an asset or liability under any other IFRS are segregated on the statement of financial position, on the statement of income and comprehensive income as net movements in regulatory balances, net of tax, and on the statement of income and comprehensive income as net movements in regulatory balances related to CCI, net of tax. The netting of regulatory debit and credit balances is not permitted.

The measurement of regulatory balances is subject to certain estimates and assumptions. including assumptions made *in* the interpretation of the OEB's regulations and decisions.

(j) Employee future benefits:

Pension plan:

The Corporation provides a pension plan for all its full-time employees through Ontario Municipal Employees Retirement System (“OMERS”). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund (“the Fund”), and provides pensions for employees of Ontario municipalities, local boards and public utilities. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund. To the extent that the Fund finds itself in an under-funded position, additional contribution rates may be assessed to participating employers and members.

OMERS is a defined benefit plan. However, as OMERS does not segregate its pension asset and liability information by individual employers, there is insufficient information available to enable the Corporation to directly account for the plan. Consequently, the plan has been accounted for as a defined contribution plan. Obligations for contributions to defined contribution pension plans are recognized as an employee benefit expense in net income when they are due.

3. Significant accounting policies (continued):

(k) Finance income and finance costs:

Finance income is recognized as it accrues in profit or loss, using the effective interest method. Finance income comprises interest earned on cash and cash equivalents and on regulatory assets and dividend payments.

Finance charges comprise interest expense on borrowings and regulatory. Finance costs are recognized as an expense unless they are capitalized as part of the cost of qualifying assets.

(l) Income taxes:

The income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case, it is recognized in equity.

The Corporation is currently exempt from taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act (collectively the "Tax Acts"). Under the *Electricity Act*, 1998, the Corporation makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations. Prior to October 1, 2001, the Corporation was not subject to income or capital taxes. Payments in lieu of taxes are referred to as income taxes.

Current tax is the 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 tax is recognized using the balance sheet method. Under this method, deferred income taxes reflect the net tax effects of temporary differences between the tax basis of assets and liabilities and their 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. Deferred tax 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 tax 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.

4. Cash and cash equivalents:

Cash and cash equivalents consist of overnight deposits at a Canadian chartered bank.

5. Accounts receivable:

	2017	2016
Trade receivables	$ 227,653	$ 298,585
Billable work	2,600	1,978
Less allowance for doubtful accounts	(48,307)	(54,074)
	$ 181,946	$ 246,489

6. Inventory:

The amount of inventories consumed by the Corporation and recognized as an expense during 2017 was $12,177 (2016 - $14,298).

7. Property, plant and equipment:

(a) Cost:

	Land	Transmission and Distribution Systems	Meters	Total
Balance at January 1, 2017	$ 141	$ 843,288	$ 309,728	$1,153,157
Additions		4,389	19,668	24,057
Balance at December 31, 2017	$ 141	$ 847,677	$ 329,396	$1,177,214

	Land	Transmission and Distribution Systems	Meters	Total
Balance at January 1, 2016	$ 141	$ 807,995	$ 308,728	$1,116,864
Additions	–	35,293	1,000	36,293
Balance at December 31, 2016	$ 141	$ 843,288	$ 309,728	$1,153,157

7. Property, plant and equipment (continued):

(b) Accumulated depreciation:

	Land	Transmission and Distribution Systems	Meters	Total
Balance at January 1, 2017	$ –	$ 54,867	$ 58,450	$ 113,317
Depreciation charge	–	18,727	17,416	36,143
Balance at December 31, 2017	$ –	$ 73,594	$ 75,866	$ 149,460

	Land	Transmission and Distribution Systems	Meters	Total
Balance at January 1, 2016	$ –	$ 36,128	$ 40,528	$ 76,656
Depreciation charge	–	18,739	17,922	36,661
Balance at December 31, 2016	$ –	$ 54,867	$ 58,450	$ 113,317

(c) Carrying amounts:

	Land	Transmission and Distribution Systems	Meters	Total
At December 31, 2017	$ 141	$ 774,083	$ 253,530	$ 1,027,754
At December 31, 2016	$ 141	$ 788,421	$ 251,278	$ 1,039,840

8. Intangible assets:

(a) Cost:

		Computer software
Balance at January 1, 2017	$	188,462
Additions		–
Balance at December 31, 2017	$	188,462
Balance at January 1, 2016	$	188,462
Additions		–
Balance at December 31, 2016	$	188,462

(b) Accumulated amortization:

		Computer software
Balance at January 1, 2017	$	123,611
Additions		12,971
Balance at December 31, 2017	$	136,582
Balance at January 1, 2016	$	107,398
Additions		16,213
Balance at December 31, 2016	$	123,611

(c) Carrying amounts:

		Computer software
At December 31, 2017	$	51,880
At December 31, 2016	$	64,851

9. Payment in lieu of income taxes:

PIL's varies the amounts which would be computed applying the Corporation's combined statutory tax rate. The following is a reconciliation of the effective tax rate:

	2017	2016
Net income and comprehensive income for the period	$ 29,262	$ 24,034
Income tax using the Corporation's statutory tax rate	7,754	6,369
Small business deduction	(3,218)	(2,764)
Other	–	457
Change in valuation allowance	(410)	(2,160)
	$ 4,126	$ 1,902

10. Regulatory deferral account balances:

The following is a reconciliation of the carrying amount for each class of regulatory deferral account balances:

	January 1, 2017	Balances arising in the period	Recovery/ reversal	2017	Remaining recovery/ reversal period (years)
Regulatory deferral account debit balances					
Retail settlement variances	$ 249,862	$ 58,864	$ –	$ 308,726	2
Regulatory variances disposition	940,902	–	(19,445)	921,457	1
Other regulatory accounts	97,033	25,272	–	122,305	4
Total amount related to regulatory deferral account debit balances	$ 1,287,797	$ 84,136	$ (19,445)	$1,352,488	

	January 1, 2017	Balances arising in the period	Recovery/ reversal	2017	Remaining recovery/ reversal period (years)
Regulatory deferral account credit balances					
Retail settlement variances	$ 340,778	$ –	$ (13,015)	$ 327,763	2
Regulatory variances disposition	771,167	–	(19,414)	751,753	1
Other regulatory accounts	139,659	176	–	139,835	4
Total amount related to regulatory deferral account credit balances	$ 1,251,604	$ 176	$ 32,429	$ 1,219,351	

10. Regulatory deferral account balances (continued):

	January 1, 2016	Balances arising in the period	Recovery/ reversal	2016	Remaining recovery/ reversal period (years)
Regulatory deferral account debit balances					
Retail settlement variances	$ 190,409	$ 59,453	$ –	$ 249,862	2
Regulatory variances disposition	925,156	86,920	(71,174)	940,902	1
Other regulatory accounts	91,485	5,548	–	97,033	4
Total amount related to regulatory deferral account debit balances	$ 1,207,050	$ 151,921	$ (71,174)	$1,287,797	

	January 1, 2016	Balances arising in the period	Recovery/ reversal	2016	Remaining recovery/ reversal period (years)
Regulatory deferral account credit balances					
Retail settlement variances	$ 282,234	$ 58,544	$ –	$ 340,778	2
Regulatory variances disposition	795,483	46,844	(71,160)	771,167	1
Other regulatory accounts	133,633	6,026	–	139,659	4
Total amount related to regulatory deferral account credit balances	$ 1,211,350	$ 111,414	$ (71,160)	$1,251,604	

Settlement of the retail settlement variance accounts is done on an annual basis through application to the OEB. An application will be made to the OEB to recover the 2014 retail settlement variance accounts and the 1595 variance accounts. As of the date of approval of the financial statements, the application has not been submitted. Once approval is received, the approved account balance is moved to the regulatory settlement account. The balance is to be recovered over a period of one to four years.

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 Corporation in accordance with policies set out by the OEB or upon termination of their electricity distribution service.

12. Share capital:

	2017	2016
Authorized:		
Unlimited number of common shares		
Unlimited number of Class B special shares		
Issued:		
1,121,529 common shares	$ 1,121,529	$ 1,121,529
1,121,529 Class B special shares	1,121,529	1,121,529
	$ 2,243,058	$ 2,243,058

13. Other operating revenue:

Other operating revenue comprises:

	2017	2016
Rendering of services	$ 21,946	$ 38,001
Late payment charges	5,682	5,781
Total other operating revenue	$ 27,628	$ 43,782

14. Commitments and contingencies:

General

From time to time, the Corporation is involved in various litigation matters arising in the ordinary course of its business. The Corporation has no reason to believe that the disposition of any such current matter could reasonably be expected to have a materially adverse impact on the Corporation's financial position, results of operations or its ability to carry on any of its business activities.

General Liability Insurance:

The Corporation is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE). MEARIE is a pooling of public liability insurance risks of many of the LDCs in Ontario. All members of the pool are subjected to assessment for losses experienced by the pool for the years in which they were members, on a pro-rata basis based on the total of their respective service revenues. As at December 31, 2017, no assessments have been made.

15. Pension agreement:

The Corporation provides a pension plan for its employees through OMERS. The plan is a multi-employer, contributory defined pension plan with equal contributions by the employer and its employees. In 2017, the Corporation made employer contributions of $31,360 to OMERS (2016 - $30,091).

The Corporation estimates that a contribution of $36,500 to OMERS during the next fiscal year.

16. Employee benefits:

	2017	2016
Salaries, wages and benefits	$ 293,186	$ 264,321
CPP and EI remittances	14,465	17,664
Contributions to OMERS	31,360	30,091
	$ 339,011	$ 312,076

17. Related party transactions:

(a) Parent and ultimate controlling party:

The sole shareholder of the Corporation is the Corporation of the Township of Chapleau. Chapleau Public Utilities Corporation is a wholly-owned subsidiary of the Township of Chapleau. The Township produces financial statements that are available for public use.

(b) Entity with common ownership:

The Corporation is related to Chapleau Energy Services by virtue of common ownership.

(c) Key management personnel:

The key management personnel of the Corporation have been defined as members of its board of directors and executive management team members, and is summarized below.

	2017	2016
Directors' fees	$ 13,100	$ 13,200
Salaries and other short-term benefits	109,622	87,775
	$ 122,722	$ 100,975

(d) Transactions with entity with common ownership:

In the ordinary course of business, the Corporation has a cost sharing agreement with Chapleau Energy Services. The Corporation was charged $487,733 (2016 - $474,738) by Chapleau Energy Services for the Corporation's portion of certain shared costs.

17. Related party transactions (continued):

(e) Transactions with the Township of Chapleau:

The Corporation delivers electricity to the Township throughout the year for the electricity needs of the Township and its related organizations. Electricity delivery charges are at prices and under terms approved by the OEB.

The Corporation billed the Township $451,443 (2016 - $500,592) for power purchased. Included accounts receivable and unbilled revenue is $Nil (2016 - $Nil) relative to power purchased as of December 31, 2017.

18. 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 Corporation understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Corporation's exposure to a variety of risks such as credit risk, interest rate risk, and liquidity risk, as well as related mitigation strategies are discussed below.

(a) Credit risk:

Financial assets carry credit risk that a counterparty will fail to discharge an obligation which could result in a financial loss. Financial assets held by the Corporation, such as accounts receivable, expose it to credit risk. The Corporation earns its revenue from a broad base of customers located in the Township of Chapleau. No single customer accounts for a balance in excess of 4% 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, 2017 is $48,307 (2016 - $54,074). An impairment loss of $Nil (2016 - $6,763) was recognized during the year.

The Corporation's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2017, approximately $46,933 (2016 - $39,462) is considered 60 days past due. The Corporation has over 1,236 customers, the majority of whom are residential. Credit risk is managed through collection of security deposits from customers in accordance with directions provided by the OEB. As at December 31, 2017, the Corporation holds security deposits in the amount of $20,584 (2016 - $27,979).

18. Financial instruments and risk management (continued):

(b) Market risk:

Market risks primarily refer to the risk of loss resulting from changes in commodity prices, foreign exchange rates, and interest rates. The Corporation currently does not have any material commodity or foreign exchange risk.

(c) Liquidity risk:

The Corporation monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest exposure.

The Corporation is 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 the Corporation fails to make a payment required by default notice issued by the IESO. At December 31, 2017, no amounts have been drawn on this letter of credit in the amount of $209,813 (2016 - $209,813).

The majority of accounts payable, as reported on the balance sheet, are due within 30 days.

(d) Capital disclosures:

The main objectives of the Corporation, when managing capital, are to ensure ongoing access to funding to maintain and improve the electricity distribution system, compliance with covenants related to its credit facilities, prudent management of its capital structure with regard for recoveries of financing charges permitted by the OEB on its regulated electricity distribution business, and to deliver the appropriate financial returns.

The Corporation's definition of capital includes shareholder's equity. As at December 31, 2017, shareholder's equity amounts to $2,086,464 (2016 - $2,059,104).

19. Subsequent event:

On January 1, 2018, Chapleau Energy Sources was amalgamated with the Corporation. Going forward, the results of the combined operations will be presented within the Corporation's financial results. All assets and liabilities of Chapleau Energy Sources were transferred to the Corporation as of the date of amalgamation.

Appendix D Reconciliation for RRR to FS

Chapleau Public Utilities Corporation - Licence # ED-2002-0528

2.1.13 - Mapping of Trial Balance to Financial Statements - 2014

ASSETS

Trial Balance 2.1.7					**Audited Financial Statements**		
Account #'s	**F/S Section**	**F/S Line Grouping**	**GL Acct Description**		**Current Assets**		
1005	Current Assets	Bank indebtedness	Cash	91,805.41	Cash	91,805.00	
1070	Current Assets	Investments	Current Investments	254,818.73	Investments	254,819.00	
1100	Current Assets	Trades Receivables	Customer Acct's Receivable	389,117.07			
1105	Current Assets	Trades Receivables	cct's Receivable - Merchandise Jobbi	561.75	Trades Receivable	347,538.00	
1130	Current Assets	Trades Receivables	umulated Provision for uncollectable a	(42,140.67)	Unbilled Revenue		
1120	Current Assets	Unbilled Revenue	Accrued Utility Revenues	462,993.97	Energy Sales	411,121.00	
1200	Current Assets	Receivables	ts Receivable from Associated Compa	587,519.74	Distribution	51,873.00	
				-	Prepaid	6,554.00	
					Advances to relat	146,914.00	
Current Assets =				1,744,676.00			
1330	Current Assets	Inventory	Plant Materials & Operating Supplies	51,703.95	Plant materials & :	51,704.00	
Total Inventory				51,703.95	**TOTAL CURRENT ASSETS**		1,362,328.00
1508	Regulatory Asset	Regualtory Asset	Other Regulatory Assets	36,261.47	Regulatory Assets	848,205.00	
1518	Regulatory Asset	Regulatory Asset	RSVARetail	3,881.24			
1521	Other Liabilities	Regulatory Liability	SPC Variance Acct	(36.58)			
1550	Regulatory Asset	Regualtory Asset	LV Variance Account	39,576.28			
1551	Regulatory Asset	Regualtory Asset	SME	1,600.30			
1555	Regulatory Asset	Regulatory Asset	Smart Meter Capital	24,533.25			
1563	Other Liabilities	Regulatory Liability	Deferred Pils Contra Account	71,159.91			
1568	Other Liabilities	Regulatory Liability	LRAM - 2012	(9,753.85)			
1576	Other Liabilities	Regulatory Liability	Accounting chgs under CGAAP	(44,455.39)			
1580	Other Liabilities	Regulatory Liability	RSVAWMS	(28,302.43)			
1584	Other Liabilities	Regulatory Liability	RSVANW	(2,267.97)			
1586	Other Liabilities	Regulatory Liability	RSVACN	(1,764.83)			
1588	Other Liabilities	Regulatory Liability	RSVAPower	(162,082.42)			
1589	Regulatory Asset	Regulatory Asset	RSVAGA	125,652.49			
1592	Regulatory Asset	Regulatory Asset	Tax variance HST/OVAT	4,683.51			
1595	Other Liabilities	Regulatory Liability	isposition & Recovery of Regulatory E	(25,042.17)			
Total Other Assets and Deferred Chgs				33,642.81	**Property,plant and equipment**	2,694,186.00	
1705	operty, Plant & equipm	Asset	Land	140.50			
1815	operty, Plant & Equipm	Asset	ans Station Equip-Normally above 50	512,923.04			
1830	operty, Plant & Equipm	Asset	Poles, Towers and Fixtures	1,152,819.59			
1840	operty, Plant & Equipm	Asset	Underground Conduit	77,510.59			
1845	operty, Plant & Equipm	Asset	Underground Conductors & Devices	3,515.64			

1850	ɔperty, Plant & Equipm	Asset	Line Transformers	401,746.91
1860	ɔperty, Plant & Equipm	Asset	Meters	411,206.72
1920	ɔperty, Plant & Equipm	Asset	Computer Equipment - Hardware	661.42
1925	ɔperty, Plant & Equipm	Asset	Computer Software	68,661.77
1925.001	ɔperty, Plant & Equipm	Asset	omputer Software - Asset Managemer	65,000.00
1990	Current Assets	Prepaid expenses	Other Tangible Property	6,554.00
Total Other Capital Assets				2,700,740.18
Total Accumulated Dep.				
2105	ccumulated amortization			(1,623,262.83)
Net Assets				2,907,500.11

Less accumulated amortization	(1,623,263.00)
Net Assets	3,281,456.00

LIABILITIES

2205	Current Liabilities	nts payable & Accrued Lia	Accounts Payable	(366,306.36)
2208	Current Liabilities	nts payable & Accrued Lia	Customer Credit Balances	(15,214.28)
2220	Current Liabilities	nts payable & Accrued Lia	Misc Current & Accrued Liabilities	(25,210.67)
2240	Current Assets	Payable	cct's Payable to Associated Compani	(440,605.48)
2250	Current Liabilities	nts payable & Accrued Lia	DRC Payable	(19,595.18)
2290	Current Liabilities	nts payable & Accrued Lia	Commodity Taxes	(12,727.69)
2292	Current Liabilities	nts payable & Accrued Lia	Payroll Deduction/Expenses Payable	-
Current Liabilities				(879,659.66)
Non-Current Liabilities				
2335	Other Liabilities	Customer Deposits	Customer Deposits	(28,633.61)
3005	Shareholder's equity	Share capital	Common Shares Issued	(1,121,529.37)
3008	Shareholder's equity	Share capital	Preference Shares Issued	(1,121,529.36)
3045	Shareholder's equity	Deficit	Unappropriated Retained Earnings	392,336.88
3046	Shareholder's equity	Deficit	Balance Transferred From Income	(148,484.99)
Shareholder's Equity				(1,999,206.84)
Net Liabilities & Equity				(2,907,500.11)

CURRENT LIABILITIES		
Accts payable & Accrued liabilities	439,054.00	
OTHER LIABILITIES		
Regulatory Liabilitie	814,562.00	
Customer Deposits	28,634.00	
Sharehoder's Equity		
Share Capital	2,243,058.00	
Deficit	(243,852.00)	
	Net Liabilities	3,281,456.00

REVENUES
Sales of electricity

4006	Revenue	Energy Sales	Residential Energy Sales	(1,586,360.68)
4025	Revenue	Energy Sales	Street Light Energy Sales	(30,450.19)

4030	Revenue	Energy Sales	Setninel Light Energy Sales	(2,329.75)
4035	Revenue	Energy Sales	General Energy Sales	(1,196,155.95)
4050	Revenue	Energy Sales	Revenue Adjustment	(84,287.82)
4055	Revenue	Energy Sales	Energy Sales for Resale	(110,539.84)
4062	Revenue	Energy Sales	Billed WMS	(198,377.23)
4066	Revenue	Energy Sales	Billed NW	(216,671.34)
4068	Revenue	Billed Energy Sales	Billed CN	(49,681.18)
4075	Revenue	Billed Energy Sales	Billed LV	(19,856.55)
4076	Revenue	Distribution Services	SME Charges	(12,895.64)
Total				(3,507,606.17)
Distribution Service Revenue				
4080	Revenue	Distribution Services	Distribution Service Revenue	(940,653.66)
4082	Revenue	Distribution Services	Retail Service Revenue	(2,762.70)
4086	Revenue	Distribution Services	SSS Administration Revenue	(4,934.64)
Total				(948,351.00)
Total				(4,455,957.17)
Other Operating Revenue				
4210	Other income (expense	Miscellaneous	Rent from Electric Property	(13,519.11)
4225	Other income(expense)	Late payment charges	Late Payment Charges	(7,545.52)
4235	Other income (expense	Miscellaneous	Miscellaneous Service Revenues	(9,142.17)
Total				(30,206.80)
Other Income/Deductions				
4305	Regulatory Debit			20,042.00
4325	Other income (expense)			-6,121.48
Total Other Income				13,920.52
Investment Income				
4405	Other income (expense)			(14,074.48)
Total Revenues				(4,486,317.93)
EXPENSES				
Power Supply				
4705	Expenses	Power purchased	Power Purchased	3,010,124.23
4708	Expenses	Power purchased	Charges-WMS	198,377.23

Energy Sales	3,507,606.00	
Distribution Servi	928,309.00	
Total		4,435,915.00

Other income (expenses):	
Interest earned	14,074.00
Late payment chgs	7,546.00
Miscellaneous	28,783.00
Other Interest	(6,037.00)
Donations	(2,000.00)
Total	42,366.00

4714	Expenses	Power purchased	Charges-NW	216,671.34
4716	Expenses	Power Purchased	Charges-CN	49,681.18
4750	Expenses	Power Purchased	Charges-LV	19,856.55
4751	Expenses	Power Purchased	SME Charge	12,895.64
Total				3,507,606.17
Operations				
5016	Expenses	Operations & Maintenanc	ist. Station Equip. - Operations Labou	2,530.90
5017	Expenses	Operations & Maintenanc	ist. Station Equip.-Supplies & Expens	859.22
5020	Expenses	Operations & Maintenanc	OH Dist. Lines-Operation Labour	179,100.73
5025	Expenses	Operations & Maintenanc	OH Dist. Lines.-Supplies & Expenses	36,130.52
5065	Expenses	M&A and Billing & Collecti	Meter Expense	1,675.40
5095	Expenses	Operations & Maintenanc	Other Rent	2,913.77
Total				223,210.54
Billing & Collecting				
5310	Expenses	Billing & Collection	Meter Reading Expense	30,966.66
5315	Expenses	Billing & Collection	Customer Billing	74,871.41
5335	Expenses	Billing & Collection	Bad Debt Expense	29,771.17
Total				135,609.24
Communtiy Relations				
5410	Expenses	Admin & Gen Expenses	Community Relations	415.00
Admin & Gen				
5605	Expenses	Admin & General	Executive Salaries & Expenses	12,200.00
5610	Expenses	Admin & General	Management Salaries & Expenses	60,027.29
5615	Expenses	Operations & Maintenanc	Gen Administrative Salaries & Expen	14,999.81
5620	Expenses	Admin & General	Office Supplies & Expenses	20,587.31
5630	Expenses	Admin & General	Outside Services Employed	49,125.20
5635	Expenses	Admin & General	Property Insurance	13,769.97
5640	Expenses	Operations & Maintenanc	Injuries & Damages	7,499.82
5645	Expenses	Operations & Maintenanc	Employee Pensions & Benefits	69,280.03
5655	Expenses	Admin & General	Regulatory Expense	7,225.81
5665	Expenses	Admin & General	Misc General Expense	128,723.25
Total				383,438.49
Amortization Expense				72,465.66
Interest Expense				
6035	Interest Expenses	Other income (expense)	Other Income Expense	6,037.39
Taxes				
6105	Expenses	OM & A	Taxes Other than Income tax	7,050.45
Donations				
6205	Other Deductions	Other income (expense)	Donations	2,000.00
Total Expenses				4,337,832.94

EXPENSES:		
Power purchased	$3,507,606	
Operations & Maintenance	322,041	
Billing & Collectio	135,609	
Administration & (	292,074	
Amortization of Property plant & equipment	72,466	
Total Expenses		4,329,796

Net income (loss) and comprehensive income 148,485

COMMENTS

ASSETS:

1 - Financial statements has Prepaid expenses account 1990 $6554.00 under Current Assets where as RRR filing has it under Total Other Assets & Deferred Charges.

2 - Financial Statements has sum of account 1200 Accounts Receivable from Associated Companies of $587,519.74 and account 2240 Accounts Payable from Associated Companies ($440,605.48) = $146,914.26 under Current Assets.

OTHER OPERATING REVENUE

3 - Financial Statements has $13,519.11 rent from electric property, $9,142.17 miscellaneous service revenue and $6,121.48 Revenue from Merchandise Jobbing all grouped together under Miscellaneous totalling $28,782.73.

Distribution Service Revenue

4 - Distribution Service Revenue on financial statements is $928,309 which is the sum of account 4080 $(940,653.66), acct 4082 - $(2,762.70), account 4086 - $(4,934.64), and account 4305 - Regulatory Debits $20,042.00 as per July 2012 FQ's
re: estimates of useful lives of certain items of property, plant & equipment & as a result changed it amortization rates.(Page 9, 1. (j).

Administration & General

5 - On Financial Statements accounts 5615 Gen Administrative Salaries & Expenses - $14,999.81, 5640 - Injuries & Damages - $7,499.82, 5645 - Employee Pension & Benefits $69,280.03 and 6105 Taxes other than income tax - $7,050.45 are under OM&A.

TAXES

6 - Account 6105 other income taxes $7,050.45 on financial statements is under O & M.

OTHER DEDUCTIONS

7 - Financial Statements has account 6035 - Other Expense - $6,037.39 and account 6205 - Donations - $2,000.00 under Other Income (expenses) not Interest Expense and Other Deductions

Chapleau Public Utilities Corporation - Licence # ED-2002-0528

2.1.13 - Mapping of Trial Balance to Financial Statements - 2015

ASSETS

Trial Balance 2.1.7

Account #'s	F/S Section	F/S Line Grouping	GL Acct Description	
1005	Current Assets	Bank indebtedness	Cash	313,657.89
1070	Current Assets	Investments	Current Investments	262,266.94
1100	Current Assets	Trades Receivables	Customer Acct's Receivable	260,922.36
1105	Current Assets	Trades Receivables	cct's Receivable - Merchandise Jobbi	1,270.38
1130	Current Assets	Trades Receivables	ımulated Provision for uncollectable	(54,845.10)
1120	Current Assets	Unbilled Revenue	Accrued Utility Revenues	470,041.61
1200	Current Assets	Receivables	ts Receivable from Associated Comp	521,752.72
				-
Current Assets =				1,775,066.80
1330	Current Assets	Inventory	Plant Materials & Operating Supplies	50,763.35
Total Inventory				50,763.35
1508	Regulatory Asset	Regualtory Asset	Other Regulatory Assets	37,992.53
1518	Regulatory Asset	Regulatory Asset	RSVARetail	5,337.87
1521	Other Liabilities	Regualatory Liability	SPC Variance Acct	(36.58)
1550	Regulatory Asset	Regualtory Asset	LV Variance Account	110,948.96
1551	Regulatory Asset	Regualtory Asset	SME	(268.30)
1555	Regulatory Asset	Regulatory Asset	Smart Meter Capital	10,232.52
1563	Other Liabilities	Regualatory Liability	Deferred Pils Contra Account	20,887.15
1568	Other Liabilities	Regualatory Liability	LRAM - 2012	(9,753.85)
1576	Other Liabilities	Regualatory Liability	Accounting chgs under CGAAP	(89,923.39)
1580	Other Liabilities	Regualatory Liability	RSVAWMS	(46,109.07)
1584	Other Liabilities	Regualatory Liability	RSVANW	(7,590.45)
1586	Other Liabilities	Regualatory Liability	RSVACN	(1,255.54)
1588	Other Liabilities	Regualatory Liability	RSVAPower	(216,237.30)
1589	Regulatory Asset	Regualtory Asset	RSVAGA	73,138.58
1592	Regulatory Asset	Regualtory Asset	Tax variance HST/OVAT	0.00
1595	Other Liabilities	Regualatory Liability	isposition & Recovery of Regulatory I	108,335.36
Total Other Assets and Deferred Chgs				(4,301.51)
1705	ɔperty, Plant & equipm	Asset	Land	140.50
1815	ɔperty, Plant & Equipm	Asset	ans Station Equip-Normally above 50	512,923.04
1830	ɔperty, Plant & Equipm	Asset	Poles, Towers and Fixtures	1,193,087.40
1840	ɔperty, Plant & Equipm	Asset	Underground Conduit	77,510.59
1845	ɔperty, Plant & Equipm	Asset	Underground Conductors & Devices	3,515.64

Audited
Financial Statements

Current Assets		
Cash and cash eq	**313,658.00**	
Short-term Invest	**262,267.00**	
Accounts receiva	**207,348.00**	
Unbilled Revenue	**470,042.00**	
Prepaid expenses	**5,900.00**	
Due from related	81,147.00	
Inventory	**50,763.00**	
TOTAL CURRENT ASSETS		1,391,125.00
Regulatory deferr	1,207,050.00	
Property,plant and equipment	1,040,208.00	
Intangible assets	81,063.00	

1850	›perty, Plant & Equipm	Asset	Line Transformers	407,333.52
1860	›perty, Plant & Equipm	Asset	Meters	411,727.27
1920	›perty, Plant & Equipm	Asset	Computer Equipment - Hardware	661.42
1925	›perty, Plant & Equipm	Asset	Computer Software	68,661.77
1925.001	›perty, Plant & Equipm	Asset	omputer Software - Asset Manageme	119,800.00
1990	Current Assets	Prepaid expenses	Other Tangible Property	5,900.00
Total Other Capital Assets				2,801,261.15
Total Accumulated Dep.				
2105	ccumulated amortizatior			(1,674,089.44)
Net Assets				2,948,700.35
		LIABILITIES		
2205	Current Liabilities	nts payable & Accrued Li	Accounts Payable	(384,341.10)
2208	Current Liabilities	nts payable & Accrued Li	Customer Credit Balances	(21,777.63)
2220	Current Liabilities	nts payable & Accrued Li	Misc Current & Accrued Liabilities	(25,210.67)
2240	Current Assets	Payable	cct's Payable to Associated Compani	(440,605.48)
2250	Current Liabilities	nts payable & Accrued Li	DRC Payable	(15,486.58)
2290	Current Liabilities	nts payable & Accrued Li	Commodity Taxes	(1,151.82)
2292	Current Liabilities	nts payable & Accrued Li	Payroll Deduction/Expenses Payable	-
Current Liabilities				(888,573.28)
Non-Current Liabilities				
2335	Other Liabilities	Customer Deposits	Customer Deposits	(25,053.61)
3005	Shareholder's equity	Share capital	Common Shares Issued	(1,121,529.37)
3008	Shareholder's equity	Share capital	Preference Shares Issued	(1,121,529.36)
3045	Shareholder's equity	Deficit	Unappropriated Retained Earnings	243,852.00
3046	Shareholder's equity	Deficit	Balance Transferred From Income	(35,866.37)
Shareholder's Equity				(2,035,073.10)
Net Liabilities & Equity				(2,948,699.99)
REVENUES				
Sales of electricity				
4006	Revenue	Energy Sales	Residential Energy Sales	(1,460,008.86)
4025	Revenue	Energy Sales	Street Light Energy Sales	(31,206.60)

Less accumulated amortization		
Net Assets	3,719,446.00	
CURRENT LIABILITIES		
Accts payable & Accrued liabilities	447,972.00	
OTHER LIABILITIES		
Regulatory Liabilitie	1,211,350.00	
Customer Deposits	25,054.00	
Shareholder's Equity		
Share Capital	2,243,058.00	
Deficit	(207,988.00)	
	Net Liabilities	3,719,446.00

4030	Revenue	Energy Sales	Setninel Light Energy Sales	(2,116.45)				
4035	Revenue	Energy Sales	General Energy Sales	(1,214,915.95)				
4050	Revenue	Energy Sales	Revenue Adjustment	(18,603.16)				
4055	Revenue	Energy Sales	Energy Sales for Resale	(28,737.15)				
4062	Revenue	Energy Sales	Billed WMS	(112,378.05)				
4066	Revenue	Energy Sales	Billed NW	(176,759.61)				
4068	Revenue	Billed Energy Sales	Billed CN	(43,241.21)		**Energy Sales**	3,115,911.00	
						Distribution Servi	784,587.00	
4075	Revenue	Billed Energy Sales	Billed LV	(17,265.37)				
4076	Revenue	Distribution Services	SME Charges	(10,678.94)				
Total				(3,115,911.35)				
Distribution Service Revenue								
4080	Revenue	Distribution Services	Distribution Service Revenue	(822,671.63)				
4082	Revenue	Distribution Services	Retail Service Revenue	(2,705.60)				
4086	Revenue	Distribution Services	SSS Administration Revenue	(4,677.63)				
							Total	3,900,498.00
Total				(830,054.86)				
Total				(3,945,966.21)				
Other Operating Revenue						Other Operating R	30,138	
4210	Other income (expense	Miscellaneous	Rent from Electric Property	(13,519.11)				
4225	Other income(expense	Late payment charges	Late Payment Charges	(6,479.74)				
4235	Other income (expense	Miscellaneous	Miscellaneous Service Revenues	(7,995.00)				
Total				(27,993.85)				
Other Income/Deductions								
4305	Regulatory Debit			45,468.00				
4325	Other income (expense)			-2,145.46				
Total Other Income				43,322.54		Other Income		
						Finance Income	13,641.00	
Investment Income						Finance Charge	(4,490.00)	
							9,151.00	
4405	Other income (expense)			(13,641.27)				
Total Revenues				(3,944,278.79)				3,939,787.00
EXPENSES								
Power Supply								
4705	Expenses	Power purchased	Power Purchased	2,755,588.17				
4708	Expenses	Power purchased	Charges-WMS	112,378.05				

4714	Expenses	Power purchased	Charges-NW	176,759.61
4716	Expenses	Power Purchased	Charges-CN	43,241.21
4750	Expenses	Power Purchased	Charges-LV	17,265.37
4751	Expenses	Power Purchased	SME Charge	10,678.94
Total				3,115,911.35
Operations				
5016	Expenses	Operations & Maintenanc	ist. Station Equip. - Operations Labo	3,467.60
5017	Expenses	Operations & Maintenanc	ist. Station Equip.-Supplies & Expens	0.00
5020	Expenses	Operations & Maintenanc	OH Dist. Lines-Operation Labour	171,305.24
5025	Expenses	Operations & Maintenanc	OH Dist. Lines.-Supplies & Expenses	30,993.76
5065	Expenses	M&A and Billing & Collect	Meter Expense	572.37
5095	Expenses	Operations & Maintenanc	Other Rent	1,900.34
Total				208,239.31
Billing & Collecting				
5310	Expenses	Billing & Collection	Meter Reading Expense	32,959.16
5315	Expenses	Billing & Collection	Customer Billing	78,035.35
5335	Expenses	Billing & Collection	Bad Debt Expense	18,900.41
Total				129,894.92
Communtiy Relations				
5410	Expenses	Admin & Gen Expenses	Community Relations	115.00
Admin & Gen				
5605	Expenses	Admin & General	Executive Salaries & Expenses	13,200.00
5610	Expenses	Admin & General	Management Salaries & Expenses	60,694.78
5615	Expenses	Operations & Maintenanc	Gen Administrative Salaries & Expen	14,457.16
5620	Expenses	Admin & General	Office Supplies & Expenses	25,504.86
5630	Expenses	Admin & General	Outside Services Employed	110,675.31
5635	Expenses	Admin & General	Property Insurance	14,916.10
5640	Expenses	Operations & Maintenanc	Injuries & Damages	7,020.81
5645	Expenses	Operations & Maintenanc	Employee Pensions & Benefits	63,952.77
5655	Expenses	Admin & General	Regulatory Expense	7,774.19
5665	Expenses	Admin & General	Misc General Expense	72,119.59
Total				390,315.57
Amortization Expense				50,826.61
Interest Expense				
6035	Interest Expenses	Other income (expense)	Other Income Expense	4,490.20
Taxes				
6105	Expenses	OM & A	Taxes Other than Income tax	6,619.46
Donations				
6205	Other Deductions	Other income (expense)	Donations	2,000.00
Total Expenses				3,908,412.42

EXPENSES:	
Energy purchases	$3,096,735
Operations & Maintenance	300,290
Billing & Collectic	129,895
Administration &	300,886
Depreciation	50,827
Other Costs	2,000
Net movement in	23,290
Total Expenses	3,903,923

Net income (loss) and comprehensive income 35,866

COMMENTS

ASSETS:
1 - Account 1200 - $521,752.72 and 2240 - ($440,605.48) are grouped on Financial statements in Current Assets under Due from related parties for a total of $81,147
2 - Property, plant and equipment on the Financial Statements is net the accumulated depreciation
3 - The Regulatory deferral accounts are listed on the Asset side $1,207,050 and on the liability side ($1,211,350) of the Financial Statements
4 - Financial statements has Prepaid expenses account 1990 $5,900.00 under Current Assets where as RRR filing has it under Total
Other Assets & Deferred Charges.

LIABILITIES
1 - Fianancial Statements have the Regulatory deferral account on both the Asset and Liability side where as RRR filing has the total only on the Asset side

Revenues
1 - Financial Statements have account 4305 Regulatory Debit $45,468 under Distribution Services Revenue whereas RRR Filing has it under Other Income/Deductions

Other Income
Fianancial statements has Other Interest Expense $4,490.20 under Other Income, RRR Filing has it under Interest Expense

Expenses Power Supply
1 -
2 - Financial Statements has accounts 5610 EHT/WSIB Expense - $7,020.81, 5615 CPP/EI Expense - $14,457.16, 5645 Employee Pension/Benefits/Insurance - $63,952.77 and 6105 Taxes Other than Income taxes $6,619.46 in Operations and maintenance, RRR filing as them under Admin & Gen and Interest Expense (6105)

Chapleau Public Utilities Corporation - Licence # ED-2002-0528

2.1.13 - Mapping of Trial Balance to Financial Statements - 2016

ASSETS

Trial Balance 2.1.7

Account #'s	F/S Section	F/S Line Grouping	GL Acct Description		Audited Financial Statements		
					Current Assets		
1005	Current Assets	Bank indebtedness	Cash	303,347.60	Cash and cash eq	303,348.00	
1070	Current Assets	Investments	Current Investments	261,296.18	Short-term Invest	261,297.00	
1100	Current Assets	Trades Receivables	Customer Acct's Receivable	298,585.05			
1105	Current Assets	Trades Receivables	cct's Receivable - Merchandise Jobbi	1,978.63	Accounts receiva	246,489.00	
1130	Current Assets	Trades Receivables	ımulated Provision for uncollectable	(54,074.21)			
1120	Current Assets	Unbilled Revenue	Accrued Utility Revenues	498,255.61	Unbilled Revenue	498,256.00	
1200	Current Assets	Receivables	ts Receivable from Associated Comp	503,776.01			
					Prepaid expenses	6,000.00	
					Due from related		63,171.00	
Current Assets =				1,813,164.87			
1330	Current Assets	Inventory	Plant Materials & Operating Supplies	36,464.89	Inventory	36,465.00	
Total Inventory				36,464.89	TOTAL CURRENT ASSETS		1,415,026.00
1508	Regulatory Asset	Regualtory Asset	Other Regulatory Assets	43,509.92	Regulatory deferr	1,287,797.00	
1518	Regulatory Asset	Regulatory Asset	RSVARetail	6,475.14			
1521	Other Liabilities	Regualatory Liability	SPC Variance Acct	(36.58)			
1550	Regulatory Asset	Regualtory Asset	LV Variance Account	153,699.85			
1551	Regulatory Asset	Regualtory Asset	SME	(295.66)			
1555	Regulatory Asset	Regulatory Asset	Smart Meter Capital	4,266.05			
1563	Other Liabilities	Regualatory Liability	Deferred Pils Contra Account	-			
1568	Other Liabilities	Regualatory Liability	LRAM - 2012	(9,753.85)			
1576	Other Liabilities	Regualatory Liability	Accounting chgs under CGAAP	(89,923.39)			
1580	Other Liabilities	Regualatory Liability	RSVAWMS	(78,048.77)			
1584	Other Liabilities	Regualatory Liability	RSVANW	(9,536.35)			
1586	Other Liabilities	Regualatory Liability	RSVACN	(1,498.98)			
1588	Other Liabilities	Regualatory Liability	RSVAPower	(241,247.25)			
1589	Regulatory Asset	Regualtory Asset	RSVAGA	89,325.97			
1592	Regulatory Asset	Regualtory Asset	Tax variance HST/OVAT	0.00			
1595	Other Liabilities	Regualatory Liability	ısposition & Recovery of Regulatory I	169,269.94			
Total Other Assets and Deferred Chgs				36,206.05	Property,plant and equipment	1,039,840.00	
					Intangible assets	64,851.00	
1705	ɔperty, Plant & equipm	Asset	Land	140.50			
1815	ɔperty, Plant & Equipm	Asset	ans Station Equip-Normally above 50	512,923.04			
1830	ɔperty, Plant & Equipm	Asset	Poles, Towers and Fixtures	1,228,371.34			
1840	ɔperty, Plant & Equipm	Asset	Underground Conduit	77,510.59			
1845	ɔperty, Plant & Equipm	Asset	Underground Conductors & Devices	3,515.64			

1850	ɔperty, Plant & Equipm	Asset	Line Transformers	407,333.52		
1860	ɔperty, Plant & Equipm	Asset	Meters	412,727.27		
1920	ɔperty, Plant & Equipm	Asset	Computer Equipment - Hardware	661.42		
1611	ɔperty, Plant & Equipm	Asset	Computer Software	188,461.77		
1990	Current Assets	Prepaid expenses	Other Tangible Property	6,000.00		
Total Other Capital Assets				2,837,645.09		
Total Accumulated Dep.					Less accumulated amortization	
2105	ccumulated amortizatior			(1,726,963.74)		
Net Assets				2,996,517.16	Net Assets	3,807,514.00

		LIABILITIES		
2205	Current Liabilities	nts payable & Accrued Li	Accounts Payable	(403,493.57)
2208	Current Liabilities	nts payable & Accrued Li	Customer Credit Balances	(31,707.77)
2220	Current Liabilities	nts payable & Accrued Li	Misc Current & Accrued Liabilities	(25,163.36)
2240	Current Assets	Payable	cct's Payable to Associated Compani	(440,605.48)
2250	Current Liabilities	nts payable & Accrued Li	DRC Payable	(6,560.05)
2290	Current Liabilities	nts payable & Accrued Li	Commodity Taxes	-
2292	Current Liabilities	nts payable & Accrued Li	Payroll Deduction/Expenses Payable	-
2294	Current Liablitities	nts payable & Accrued Li	Payment in lieu of taxes	(1,902.00)
Current Liabilities				(909,432.23)
Non-Current Liabilities				
2335	Other Liabilities	Customer Deposits	Customer Deposits	(27,978.61)
3005	Shareholder's equity	Share capital	Common Shares Issued	(1,121,529.37)
3008	Shareholder's equity	Share capital	Preference Shares Issued	(1,121,529.36)
3045	Shareholder's equity	Deficit	Unappropriated Retained Earnings	207,988.97
3046	Shareholder's equity	Deficit	Balance Transferred From Income	(24,036.55)
Shareholder's Equity				(2,059,106.31)
Net Liabilities & Equity				(2,996,517.15)

CURRENT LIABILITIES		
Accts payable & Accrued liabilities	466,925.00	
Payment in lieu of t	1,902.00	
OTHER LIABILITIES		
Regulatory Liabilitie	1,251,604.00	
Customer Deposits	27,979.00	
Sharehoder's Equity		
Share Capital	2,243,058.00	
Deficit	(183,954.00)	
	Net Liabilities	3,807,514.00

REVENUES

Sales of electricity

4006	**Revenue**	**Energy Sales**	**Residential Energy Sales**	(1,446,593.01)		
4025	**Revenue**	**Energy Sales**	**Street Light Energy Sales**	(34,345.99)		
4030	**Revenue**	**Energy Sales**	**Setninel Light Energy Sales**	(2,237.98)		
4035	**Revenue**	**Energy Sales**	**General Energy Sales**	(1,370,598.84)		
4050	**Revenue**	**Energy Sales**	**Revenue Adjustment**	(44,267.76)		
4055	**Revenue**	**Energy Sales**	**Energy Sales for Resale**	(6,870.55)		
4062	**Revenue**	**Energy Sales**	**Billed WMS**	(124,807.60)		
4066	**Revenue**	**Energy Sales**	**Billed NW**	(166,965.59)		
4068	**Revenue**	**Billed Energy Sales**	**Billed CN**	(40,390.05)		
4075	**Revenue**	**Billed Energy Sales**	**Billed LV**	(14,687.88)		
4076	**Revenue**	**Distribution Services**	**SME Charges**	(11,575.07)		
Total				(3,263,340.32)	**Energy Sales**	3,263,340.00

Distribution Service Revenue

4080	**Revenue**	**Distribution Services**	**Distribution Service Revenue**	(777,464.06)		
4082	**Revenue**	**Distribution Services**	**Retail Service Revenue**	(3,089.58)		
4086	**Revenue**	**Distribution Services**	**SSS Administration Revenue**	(4,277.22)		
Total				(784,830.86)	**Distribution Servi**	784,830.00
Total				(4,048,171.18)	**Total**	4,048,170.00

Other Operating Revenue

4210	**Other income (expense**	**Miscellaneous**	**Rent from Electric Property**	(13,519.11)		
4225	**Other income(expense**	**Late payment charges**	**Late Payment Charges**	(5,781.98)		
4235	**Other income (expense**	**Miscellaneous**	**Miscellaneous Service Revenues**	(5,580.00)		
Total				(24,881.09)	Other Operating Revenue	43,782

Other Income/Deductions

4305	**Regulatory Debit**			0.00		
4325	**Other income (expense)**			(20,055.02)		
4380	**Other income (expense)**		Expenses of Non-Utility	1,152.36		
Total Other Income				(18,902.66)	Other Income	
					Finance Income	3,650.00
Investment Income					Finance Charge	(2,425.00)
						1,225.00
4405	**Other income (expense)**			(3,649.56)		
Total Revenues				(4,095,604.49)		4,093,177.00

EXPENSES

Power Supply

4705	**Expenses**	**Power purchased**	**Power Purchased**	2,904,914.13				
4708	**Expenses**	**Power purchased**	**Charges-WMS**	124,807.60				
4714	**Expenses**	**Power purchased**	**Charges-NW**	166,965.59				
4716	**Expenses**	**Power Purchased**	**Charges-CN**	40,390.05				
4750	**Expenses**	**Power Purchased**	**Charges-LV**	14,687.88				
4751	**Expenses**	**Power Purchased**	**SME Charge**	11,575.07		**EXPENSES:**		
Total				3,263,340.32		**Energy purchases**	$3,231,301	$32,039.32

Operations

5016	**Expenses**	**Operations & Maintenanc**	**ist. Station Equip. - Operations Labo**	2,991.14
5017	**Expenses**	**Operations & Maintenanc**	**ist. Station Equip.-Supplies & Expens**	0.00
5020	**Expenses**	**Operations & Maintenanc**	**OH Dist. Lines-Operation Labour**	178,142.46
5025	**Expenses**	**Operations & Maintenanc**	**OH Dist. Lines.-Supplies & Expenses**	53,230.89

5065	Expenses	M&A and Billing & Collect	Meter Expense	514.32			
5095	Expenses	Operations & Maintenanc	Other Rent	1,453.28	Operations &		
Total				236,332.09	Maintenance	341,725	
Billing & Collecting							
5310	Expenses	Billing & Collection	Meter Reading Expense	35,466.49			
5315	Expenses	Billing & Collection	Customer Billing	78,927.15			
5335	Expenses	Billing & Collection	Bad Debt Expense	6,763.22			
Total				121,156.86	Billing & Collectic	121,158	
Communtiy Relations							
5410	Expenses	Admin & Gen Expenses	Community Relations	415.00			
Admin & Gen							
5605	Expenses	Admin & General	Executive Salaries & Expenses	13,200.00			
5610	Expenses	Admin & General	Management Salaries & Expenses	87,775.03			
5615	Expenses	Operations & Maintenanc	Gen Administrative Salaries & Expen	17,664.24			
5620	Expenses	Admin & General	Office Supplies & Expenses	26,671.68			
5630	Expenses	Admin & General	Outside Services Employed	76,785.06			
5635	Expenses	Admin & General	Property Insurance	4,421.41			
5640	Expenses	Operations & Maintenanc	Injuries & Damages	7,533.53			
5645	Expenses	Operations & Maintenanc	Employee Pensions & Benefits	73,205.46			
5655	Expenses	Admin & General	Regulatory Expense	8,933.79			
5665	Expenses	Admin & General	Misc General Expense	67,942.44			
Total				384,132.64	Administration & General		286,144
Amortization					Depreciation	52,874	
Expense				52,874.30	Other Costs	2,000	
					Net movement in	32,039	
Interest Expense					Payment in lieu of	1,902.00	
6035	Interest Expenses	Other income (expense)	Other Income Expense	2,425.49			
Taxes							
6105	Expenses	OM & A	Taxes Other than Income tax	6,989.24			
6110	Expenses		Current payment in lieu of tax	1,902.00			
Donations							
6205	Other Deductions	Other income (expense)	Donations	2,000.00			
Total Expenses				4,071,567.94	Total Expenses		4,069,143
					Net income (loss) and comprehensive income		24,034.00
				(24,036.55)			

COMMENTS

CURRENT ASSETS:

1 - Account 1200 - $503,776.01 and 2240 - ($440,605.48) are grouped on Financial statements in Current Assets under Due from related parties for a total of $63,171
2 - Financial statements has Prepaid expenses account 1990 $6,000.00 under Current Assets where as RRR filing has it under Total Other Assets & Deferred Charges.

OTHER ASSETS:

3 - The Regulatory deferral accounts are listed on the Asset side $1,287,797and on the liability side ($1,251,604) of the Financial Statements

OTHER CAPITAL ASSETS:

4 - Property, plant and equipment on the Financial Statements is net the accumulated depreciation
5 - Prepaid Expenses, acc't 1990 - $6,000.00 is under Current Assets on Financial Statements

LIABILITIES

6 - Account 1200 - $503,776.01 and 2240 - ($440,605.48) are grouped on Financial statements in Current Assets under Due from related parties for a total of $63,171
7 - The Regulatory deferral accounts are listed on the Asset side $1,287,797and on the liability side ($1,251,604) of the Financial Statements where as RRR filing has the total only on the Asset side

Other Income

8 - Fianancial statements has Other Interest Expense $2,425.49 under Other Income, RRR Filing has it under Interest Expense
9 - Payment in lieu of taxes - 1,902.00 on the Income Statement as well as the Balance Sheet

Expenses Power Supply

10 - Financial Statements has accounts 5640 EHT/WSIB Expense - $7,533.53, 5615 CPP/EI Expense - $17,664.24, 5645 Employee Pension/Benefits/Insurance - $73,205.46 and 6105 Taxes Other than Income taxes $6,989.24 in Operations and maintenance, RRR filing as them under Admin & Gen and Interest Expense (6105)

Chapleau Public Utilities Corporation - Licence # ED-2002-0528

2.1.13 - Mapping of Trial Balance to Financial Statements - 2017

ASSETS

Trial Balance 2.1.7

Account #'s	F/S Section	F/S Line Grouping	GL Acct Description		Audited Financial Statements		
					Current Assets		
1005	Current Assets	Bank indebtedness	Cash	409,729.03	Cash and cash eq	409,729.00	
1070	Current Assets	Investments	Current Investments	263,271.93	Short-term Invest	263,272.00	
1100	Current Assets	Trades Receivables	Customer Acct's Receivable	227,653.55			
1105	Current Assets	Trades Receivables	cct's Receivable - Merchandise Jobbi	2,599.58	Accounts receiva	181,946.00	
1130	Current Assets	Trades Receivables	ımulated Provision for uncollectable	(48,306.80)			
1120	Current Assets	Unbilled Revenue	Accrued Utility Revenues	404,526.38	Unbilled Revenue	404,526.00	
1200	Current Assets	Receivables	ts Receivable from Associated Comp	524,586.73			
					Prepaid expenses	6,100.00	
					Due from related	83,981.00	
Current Assets =				1,784,060.40			
1330	Current Assets	Inventory	Plant Materials & Operating Supplies	37,888.50	Inventory	37,889.00	
Total Inventory				37,888.50	TOTAL CURRENT ASSETS		1,387,443.00
1508	Regulatory Asset	Regualtory Asset	Other Regulatory Assets	68,482.42	Regulatory deferr	1,352,488.00	
1518	Regulatory Asset	Regulatory Asset	RSVARetail	7,782.88			
1521	Other Liabilities	Regualatory Liability	SPC Variance Acct	(36.58)			
1550	Regulatory Asset	Regualtory Asset	LV Variance Account	200,139.14			
1551	Regulatory Asset	Regualtory Asset	SME	(345.58)			
1555	Regulatory Asset	Regulatory Asset	Smart Meter Capital	4,310.45			
1563	Other Liabilities	Regualatory Liability	Deferred Pils Contra Account	-			
1568	Other Liabilities	Regualatory Liability	LRAM - 2012	(9,753.85)			
1576	Other Liabilities	Regualatory Liability	Accounting chgs under CGAAP	(89,923.39)			
1580	Other Liabilities	Regualatory Liability	RSVAWMS	(105,359.41)			
1584	Other Liabilities	Regualatory Liability	RSVANW	(8,629.91)			
1586	Other Liabilities	Regualatory Liability	RSVACN	2,122.47			
1588	Other Liabilities	Regualatory Liability	RSVAPower	(203,503.86)			
1589	Regulatory Asset	Regualtory Asset	RSVAGA	98,628.89			
1592	Regulatory Asset	Regualtory Asset	Tax variance HST/OVAT	0.00			
1595	Other Liabilities	Regualatory Liability	ısposition & Recovery of Regulatory I	169,224.58			
Total Other Assets and Deferred Chgs				133,138.25	Property,plant and equipment	1,027,754.00	
					Intangible assets	51,880.00	
1705	›perty, Plant & equipm	Asset	Land	140.50			
1815	›perty, Plant & Equipm	Asset	ans Station Equip-Normally above 50	512,923.04			
1830	›perty, Plant & Equipm	Asset	Poles, Towers and Fixtures	1,232,770.14			
1840	›perty, Plant & Equipm	Asset	Underground Conduit	77,510.59			
1845	›perty, Plant & Equipm	Asset	Underground Conductors & Devices	3,515.64			

1850	operty, Plant & Equipm	Asset	Line Transformers	407,333.52		
1860	operty, Plant & Equipm	Asset	Meters	432,395.21		
1920	operty, Plant & Equipm	Asset	Computer Equipment - Hardware	661.42		
1611	operty, Plant & Equipm	Asset	Computer Software	188,461.77		
1990	Current Assets	Prepaid expenses	Other Tangible Property	6,100.00		
Total Other Capital Assets				2,861,811.83		
Total Accumulated Dep.					Less accumulated amortization	
2105	ccumulated amortizatior			(1,776,077.48)		
Net Assets				3,040,821.50	Net Assets	3,819,565.00

		LIABILITIES			
2205	Current Liabilities	nts payable & Accrued Li	Accounts Payable	(400,444.82)
2208	Current Liabilities	nts payable & Accrued Li	Customer Credit Balances	(68,135.34)
2220	Current Liabilities	nts payable & Accrued Li	Misc Current & Accrued Liabilities	(25,222.07)
2240	Current Assets	Payable	cct's Payable to Associated Compani	(440,605.48)
2250	Current Liabilities	nts payable & Accrued Li	DRC Payable	9,491.32
2290	Current Liabilities	nts payable & Accrued Li	Commodity Taxes	(6,952.85)
2292	Current Liabilities	nts payable & Accrued Li	Payroll Deduction/Expenses Payable	-
2294	Current Liablitities	nts payable & Accrued Li	Payment in lieu of taxes	(4,126.00)
Current Liabilities				(935,995.24)
Non-Current Liabilities				
2335	Other Liabilities	Customer Deposits	Customer Deposits	(20,583.61)
3005	Shareholder's equity	Share capital	Common Shares Issued	(1,121,529.37)
3008	Shareholder's equity	Share capital	Preference Shares Issued	(1,121,529.36)
3045	Shareholder's equity	Deficit	Unappropriated Retained Earnings	183,952.42
3046	Shareholder's equity	Deficit	Balance Transferred From Income	(25,136.34)
Shareholder's Equity				(2,084,242.65)
Net Liabilities & Equity				(3,040,821.50)

CURRENT LIABILITIES		
Accts payable & Accrued liabilities	491,264.00	
Payment in lieu of t	4,126.00	
OTHER LIABILITIES		
Regulatory Liabilitie	1,219,351.00	
Customer Deposits	20,584.00	
Sharehoder's Equity		
Share Capital	2,243,058.00	
Deficit	(158,818.00)	
	Net Liabilities	3,819,565.00

REVENUES							
Sales of electricity							
4006	Revenue	Energy Sales	Residential Energy Sales	(1,156,025.34)			
4025	Revenue	Energy Sales	Street Light Energy Sales	(26,876.06)			
4030	Revenue	Energy Sales	Setninel Light Energy Sales	(1,794.65)			
4035	Revenue	Energy Sales	General Energy Sales	(1,173,604.06)			
4050	Revenue	Energy Sales	Revenue Adjustment	215.14			
4055	Revenue	Energy Sales	Energy Sales for Resale	(8,195.87)			
4062	Revenue	Energy Sales	Billed WMS	(96,011.83)			
4066	Revenue	Energy Sales	Billed NW	(146,701.19)			
4068	Revenue	Billed Energy Sales	Billed CN	(35,130.33)			
4075	Revenue	Billed Energy Sales	Billed LV	(12,771.80)			
4076	Revenue	Distribution Services	SME Charges	(10,520.69)			
Total				(2,667,416.68)	**Energy Sales**	2,667,417.00	
Distribution Service Revenue							
4080	Revenue	Distribution Services	Distribution Service Revenue	(762,557.08)			
4082	Revenue	Distribution Services	Retail Service Revenue	(2,748.98)			
4086	Revenue	Distribution Services	SSS Administration Revenue	(4,649.61)			
Total				(769,955.67)	**Distribution Servi**	769,956.00	
Total				(3,437,372.35)	**Total**		3,437,373.00
Other Operating Revenue							
4210	Other income (expens	Miscellaneous	Rent from Electric Property	(13,608.51)			
4225	Other income(expense	Late payment charges	Late Payment Charges	(5,682.43)			
4235	Other income (expens	Miscellaneous	Miscellaneous Service Revenues	(9,731.00)			
Total				(29,021.94)	Other Operating Revenue		27,628
Other Income/Deductions							
4305	Regulatory Debit			0.00			
4325	Other income (expense)			(14.98)			
4375	Other income (expense)		Income of Non-Utility	(16,951.90)			
4380	Other income (expense)		Expenses of Non-Utility	18,360.12			
Total Other Income				1,393.24	Other Income		
					Finance Income	9,313.00	
Investment Income					Finance Charge	(4,020.00)	
						5,293.00	
4405	Other income (expense)			(9,313.30)			

Total Revenues				(3,474,314.35)		3,470,294.00
EXPENSES						
Power Supply						
4705	Expenses	Power purchased	Power Purchased	2,366,280.99		
4708	Expenses	Power purchased	Charges-WMS	96,011.83		
4714	Expenses	Power purchased	Charges-NW	146,701.19		
4716	Expenses	Power Purchased	Charges-CN	35,130.33		
4750	Expenses	Power Purchased	Charges-LV	12,771.80		
4751	Expenses	Power Purchased	SME Charge	10,520.60	**EXPENSES:**	
Total				2,667,416.74	**Energy purchases**	$2,697,631
Operations						
5016	Expenses	Operations & Maintenance	ist. Station Equip. - Operations Labo	2,030.44		
5017	Expenses	Operations & Maintenance	ist. Station Equip.-Supplies & Expens	50.00		
5020	Expenses	Operations & Maintenance	OH Dist. Lines-Operation Labour	162,956.96		
5025	Expenses	Operations & Maintenance	OH Dist. Lines.-Supplies & Expenses	63,380.92		

5065	Expenses	M&A and Billing & Collect	Meter Expense	7,009.77			
5095	Expenses	Operations & Maintenanc	Other Rent	2,480.97	Operations &		
Total				237,909.06	Maintenance	352,656	
Billing & Collecting							
5310	Expenses	Billing & Collection	Meter Reading Expense	41,027.29			
5315	Expenses	Billing & Collection	Customer Billing	80,401.11			
5335	Expenses	Billing & Collection	Bad Debt Expense	(208.49)			
Total				121,219.91	Billing & Collectic	121,220	
Communtiy Relations							
5410	Expenses	Admin & Gen Expenses	Community Relations	415.00			
Admin & Gen							
5605	Expenses	Admin & General	Executive Salaries & Expenses	13,100.00			
5610	Expenses	Admin & General	Management Salaries & Expenses	109,621.63			
5615	Expenses	Operations & Maintenanc	Gen Administrative Salaries & Expen	14,465.42			
5620	Expenses	Admin & General	Office Supplies & Expenses	19,138.13			
5630	Expenses	Admin & General	Outside Services Employed	65,107.08			
5635	Expenses	Admin & General	Property Insurance	9,393.00			
5640	Expenses	Operations & Maintenanc	Injuries & Damages	8,624.76			
5645	Expenses	Operations & Maintenanc	Employee Pensions & Benefits	83,741.91			
5655	Expenses	Admin & General	Regulatory Expense	8,392.02			
5665	Expenses	Admin & General	Misc General Expense	23,457.91			
Total				355,041.86	Administration & General		248,625
Amortization Expense				49,113.74	Depreciation	49,114	
					Other Costs	2,000	
					Net movement in	-30,214	
Interest Expense					Payment in lieu of	4,126.00	
6035	Interest Expenses	Other income (expense)	Other Income Expense	4,019.92			
Taxes							
6105	Expenses	OM & A	Taxes Other than Income tax	7,915.78			
6110	Expenses		Current payment in lieu of tax	4,126.00			
Donations							
6205	Other Deductions	Other income (expense)	Donations	2,000.00			
Total Expenses				3,449,178.01		Total Expenses	3,445,158
					Net income (loss) and comprehensive income		25,136.00
				(25,136.34)			

COMMENTS

CURRENT ASSETS:
1 - Account 1200 - $524,586.73 and 2240 - ($440,605.48) are grouped on Financial statements in Current Assets under Due from related parties for a total of $83,981
2 - Financial statements has Prepaid expenses account 1990 $6,100.00 under Current Assets where as RRR filing has it under Total Other Assets & Deferred Charges.

OTHER ASSETS:
3 - The Regulatory deferral accounts are listed on the Asset side $1,352,488 and on the liability side ($1,219,351) of the Financial Statements

OTHER CAPITAL ASSETS:
4 - Property, plant and equipment on the Financial Statements is net the accumulated depreciation
5 - Prepaid Expenses, acc't 1990 - $6,100.00 is under Current Assets on Financial Statements

LIABILITIES
6 - Account 1200 - $524,586.73 and 2240 - ($440,605.48) are grouped on Financial statements in Current Assets under Due from related parties for a total of $83,981
7 - The Regulatory deferral accounts are listed on the Asset side $1,3525,488 and on the liability side ($1,219,351) of the Financial Statements where as RRR filing has the total only on the Asset side

Other Income
8 - Fianancial statements has Other Interest Expense $4,019.92 under Other Income, RRR Filing has it under Interest Expense
9 - Payment in lieu of taxes - 4,126 on the Income Statement as well as the Balance Sheet

Expenses Power Supply
10 - Financial Statements has accounts 5640 EHT/WSIB Expense - $8,624.76, 5615 CPP/EI Expense - $14,465.42, 5645 Employee Pension/Benefits/Insurance - $83,741.91 and 6105 Taxes Other than Income taxes $7,915.78 in Operations and maintenance, RRR filing as them under Admin & Gen and Interest Expense (6105)

Appendix E Survey Results (English)

Chapleau Public Utilities Corporation Customer Satisfaction Survey Results (2017)

Question #1

Do you currently have an account with Chapleau Public Utilities Corporation (CPUC) for your home or business?		
Answer Options	Response Percent	Response Count
Yes, my home	93.3%	167
Yes, my business	3.4%	6
Yes, both my home and business	2.2%	4
No	1.1%	2
	answered question	179
	skipped question	0

Question #2

Do you own or lease the facility where you operate your business or organization?		
Answer Options	Response Percent	Response Count
Own	83.3%	5
Lease	16.7%	1
	answered question	6
	skipped question	173

Question #3

How many employees does your business or organization have working at your location?		
Answer Options	Response Percent	Response Count
0 to 4 employees	83.3%	5
5 to 10 employees	16.7%	1
11 to 24 employees	0.0%	0
25 to 49 employees	0.0%	0
50 or more employees	0.0%	0
	answered question	6
	skipped question	173

Question #4

Do you purchase your electricity from a retailer? Retailers are companies that sell energy under contract to households and small businesses.		
Answer Options	Response Percent	Response Count
Yes	16.7%	1
No	83.3%	5
Don't know	0.0%	0
	answered question	6
	skipped question	173

Question #5

What is the primary source of heat at the facility where your business or organization is located?		
Answer Options	Response Percent	Response Count
Propane heating system	0.0%	0
Electric heating system	66.7%	4
Wood or pellets stove	0.0%	0
Oil heating system	16.7%	1
Don't know	16.7%	1
Other (please specify)		0
	answered question	6
	skipped question	173

Question #6

In which age category do you belong?		
Answer Options	Response Percent	Response Count
Under 18	0.0%	0
18-24 years	1.2%	2
25-34 years	18.1%	31
35-44 years	13.5%	23
45-64 years	47.4%	81
65-74 years	15.8%	27
75 years or older	4.1%	7
	answered question	171
	skipped question	8

Question #7

How old is your home/ apartment?		
Answer Options	Response Percent	Response Count
Less than 2 years	0.6%	1
2-5 years	0.0%	0
6-10 years	0.6%	1
11-20 years	3.5%	6
More than 20 years	91.8%	157
Don't know	3.5%	6
	answered question	171
	skipped question	8

Question #8

Do you own or rent your home?		
Answer Options	Response Percent	Response Count
Own	87.4%	146
Rent	12.6%	21
	answered question	167
	skipped question	12

Question #9

Please indicate how many people reside in your household.		
Answer Options	Response Percent	Response Count
1	19.8%	33
2	47.9%	80
3	16.2%	27
4	10.2%	17
5	5.4%	9
6+	0.6%	1
	answered question	167
	skipped question	12

Question #10

Do you purchase your electricity from a retailer? Retailers are companies that sell energy under contract to households and small businesses.		
Answer Options	Response Percent	Response Count
Yes	6.6%	11
No	77.8%	130
Don't know	15.6%	26
	answered question	167
	skipped question	12

Question #11

What is the primary source of heat for your home?		
Answer Options	Response Percent	Response Count
Propane heating system	10.3%	17
Electric heating system	46.7%	77
Wood or pellets stove	29.1%	48
Oil heating system	11.5%	19
Don't know	2.4%	4
Other (please specify)		12
	answered question	165
	skipped question	14

Question #12

Restoring service when a power outage occurs		
Answer Options	Response Percent	Response Count
Excellent	43.9%	76
Good	48.0%	83
Fair	6.9%	12
Poor	1.2%	2
	answered question	173
	skipped question	6

Question #13

Being reachable during an outage (by telephone or other means)		
Answer Options	Response Percent	Response Count
Excellent	35.3%	61
Good	51.4%	89
Fair	10.4%	18
Poor	2.9%	5
	answered question	173
	skipped question	6

Question #14

In terms of overall reliability of electric service, would you rate it as?		
Answer Options	Response Percent	Response Count
Excellent	43.9%	76
Good	47.4%	82
Fair	8.7%	15
Poor	0.0%	0
	answered question	173
	skipped question	6

Question #15

Is your electricity bill easy to understand?		
Answer Options	Response Percent	Response Count
Extremely easy	24.4%	42
Very easy	49.4%	85
Somewhat easy	25.0%	43
Not easy at all	1.2%	2
	answered question	172
	skipped question	7

Question #16

How would you rate the accuracy of your bill?		
Answer Options	Response Percent	Response Count
Excellent	20.9%	36
Good	44.2%	76
Fair	20.9%	36
Poor	3.5%	6
Don't know	10.5%	18
	answered question	172
	skipped question	7

Question #17

Please indicate the payment options you were familiar with, prior to taking this survey.		
Answer Options	Response Percent	Response Count
Payment at the office, in person	44.8%	77
Payment by mail	28.5%	49
Payment at a financial institution (Bank or Caisse)	41.9%	72
Automatic pre-authorized payment from your bank account	50.0%	86
Online or telephone banking	52.9%	91
	answered question	172
	skipped question	7

Question #18

To what extent is the cost of electricity a strain on your household or your business' budget?		
Answer Options	Response Percent	Response Count
A great deal	38.4%	66
Somewhat	44.8%	77
Not much	15.1%	26
Not at all	1.7%	3
	answered question	172
	skipped question	7

Question #19

Have you recently visited Chapleau Public Utilities Corporation's website?		
Answer Options	Response Percent	Response Count
Yes	11.0%	19
No	89.0%	153
	answered question	172
	skipped question	7

Question #20

On your most recent visit, what information were you looking for on CPUC's website? (Check all that apply)		
Answer Options	Response Percent	Response Count
Information about my bill	31.6%	6
Contact information	31.6%	6
Information about programs to help me with the cost of my bills	26.3%	5
Information about energy conservation programs	42.1%	8
Information about electricity rates	42.1%	8
Information about service changes (e.g. new service, moving, disconnection)	26.3%	5
Information about an outage	10.5%	2
Safety information	5.3%	1
Educational information	0.0%	0
Employment opportunities	0.0%	0
Other (please specify)	10.5%	2
	answered question	19
	skipped question	160

Question #20

Did you find the information you were looking for on our website?		
Answer Options	Response Percent	Response Count
Yes	84.2%	16
No	15.8%	3
	answered question	19
	skipped question	160

Question #21

Other than utility bill inserts, have you heard or seen any communications from your utility during the past 12 months?		
Answer Options	Response Percent	Response Count
Yes	31.6%	54
No	68.4%	117
	answered question	171
	skipped question	8

Question #22

Other than utility bill inserts, have you heard or seen any communications from your utility during the past 12 months?		
Answer Options	Response Percent	Response Count
Yes	31.6%	54
No	68.4%	117
	answered question	171
	skipped question	8

Question #23

Does CPUC provide you with useful information, tools, tips and assistance to help you manage your electricity consumption and bills?		
Answer Options	Response Percent	Response Count
Yes	54.4%	93
No	18.7%	32
Don't know	26.9%	46
	answered question	171
	skipped question	8

Question #24

During the past 12 months, have you contacted Chapleau Public Utilities Corporation's customer service for any information or assistance?		
Answer Options	Response Percent	Response Count
Yes	23.4%	40
No	76.6%	131
	answered question	171
	skipped question	8

Question #25

Courtesy		
Answer Options	Response Percent	Response Count
Excellent	80.0%	32
Good	15.0%	6
Fair	2.5%	1
Poor	2.5%	1
	answered question	40
	skipped question	139

Question #26

Knowledge		
Answer Options	Response Percent	Response Count
Excellent	67.5%	27
Good	30.0%	12
Fair	0.0%	0
Poor	2.5%	1
	answered question	40
	skipped question	139

Question #27

Did the customer care representative provide you with the information you needed?		
Answer Options	Response Percent	Response Count
Yes	95.0%	38
No	5.0%	2
	answered question	40
	skipped question	139

Question #28

Overall, how would you rate the customer care representative's performance in handling your request for information?		
Answer Options	Response Percent	Response Count
Excellent	75.0%	30
Good	20.0%	8
Fair	2.5%	1
Poor	2.5%	1
	answered question	40
	skipped question	139

Question #29

During the past 12 months, did you require assistance or requested information from a field employee?		
Answer Options	Response Percent	Response Count
Yes	5.8%	10
No	94.2%	161
	answered question	171
	skipped question	8

Question #30

Referring to your most recent contact with a field employee, what type of service was requested?		
Answer Options	Response Percent	Response Count
New service	20.0%	2
Repair	40.0%	4
Disconnection	0.0%	0
Upgrade	0.0%	0
Other (please specify)	40.0%	4
	answered question	10
	skipped question	169

Question #31

Courtesy		
Answer Options	**Response Percent**	**Response Count**
Excellent	80.0%	8
Good	10.0%	1
Fair	10.0%	1
Poor	0.0%	0
	answered question	10
	skipped question	169

Question #32

Knowledge		
Answer Options	**Response Percent**	**Response Count**
Excellent	80.0%	8
Good	20.0%	2
Fair	0.0%	0
Poor	0.0%	0
	answered question	10
	skipped question	169

Question #33

With this definition of sustainability in mind, how aggressively should Chapleau Public Utilities Corporation pursue and promote sustainable practices?		
Answer Options	**Response Percent**	**Response Count**
Very aggressively	26.3%	45
Somewhat aggressively	42.1%	72
Not too aggressively	12.9%	22
Not at all	1.2%	2
Don't know	17.5%	30
	answered question	171
	skipped question	8

Question #34

Please indicate which, if any, of these things your household or business has done in the past two years to reduce electricity consumption, costs, or environmental impact. (Check all that apply)		
Answer Options	Response Percent	Response Count
Changed habits to save energy, such as raising the thermostat in summer, lowering it in winter, turning off lights that are not needed, etc...	80.7%	138
Changed energy consumption habits to off-peak periods (i.e. doing laundry at night)	74.3%	127
Installed energy efficient CFL or LED light bulbs	70.8%	121
Installed a programmable thermostat	21.1%	36
Installed energy efficient doors or windows	28.7%	49
Installed a higher efficiency water heater	18.1%	31
Installed a higher efficiency heating/ cooling system	13.5%	23
Purchased an Energy Star appliance (i.e. refrigerator, stove, etc...)	37.4%	64
Installed extra insulation	26.9%	46
Requested a home-energy assessment	2.9%	5
Installed solar panels or other source of renewable energy	1.2%	2
No changes	2.3%	4
Other (please specify)	7.0%	12
	answered question	171
	skipped question	8

Number	Other (please specify)
1	installed led light bulbs every where in the house.
2	New pellet stove, new rads in rec room and basement, new patio door
3	Nothing else needed at this time - and too costly.
4	Recycle cans at hydro office
5	Replaced weather stripping around door.
6	home-energy assessment completed and new windows installed in 2010

7	I hang all my clothing on racks in the winter and on theclothes line in the summer for drying
8	Use wood heat on weekends
9	Starve till7!! How do family's survive.. !!
10	Installed an electric wood combination furnace
11	Weather stripping
12	installed propane for heating

Question #35

One of the ways to reduce consumption of fossil fuels is by providing electricity from renewable energy sources such as solar, wind, hydroelectric, or biomass, which may be more costly than conventional energy sources. Do you support renewable energy?		
Answer Options	**Response Percent**	**Response Count**
Yes, I support renewable energy, even if it causes an increase of 5% on my electricity bills	19.9%	34
Yes, I support renewable energy, even if it causes an increase of 10% on my electricity bills	3.5%	6
Yes, I support renewable energy, but only if it does not increase my electricity bills	57.3%	98
I do not support renewable energy	4.7%	8
Don't know	14.6%	25
	answered question	171
	skipped question	8

Question #36

We continue investing in the maintenance of the existing aging distribution system without any upgrades. We keep our distribution costs as they are, however high line losses will be reflected in increased costs to the customer. This will cause our distribution system to further degrade and reach its end of life, when a costly large investment will be required to keep power supply running. We will not reduce our costs for power and line losses caused by being so remote. Nor will we be able to prepare for future developments.

Answer Options	Response Percent	Response Count
Yes	19.7%	30
No	80.3%	122
Reason:		34
	answered question	152
	skipped question	27

Number	Reason:
1	upgrades are important
2	Obviously a 'head in the sand approach' that Northern customers experience more and more.
3	Delaying the inevitable
4	We need to progress, go forward and invest in the future now.
5	Don't understand
6	i think in the long run it would be better, less power outages, more reliable service
7	Like everything, upgrades are necessary and need to get done.
8	- waste of time and resources - need to plan
9	-existing problem remains unsolved
10	No point investing in something old
11	One way or the other way, we will have to upgrade the system one day, maintaining it right now is good, but not reliable, we should plan an investment on several years and increase the costs of 2 to 3% to the customer if needed.
12	Postponing inevitable

13	Seems the power is often off for upgrades and yet we still have power outages and the costs continue to increase.
14	Future developments are key, and if we cannot prepare for them we will leave ourselves stuck.
15	To continue in this direction will result in an inadequate system at the same cost and so, is economically unwise.
16	Wasted money
17	This is not a proactive approach
18	not ideal long-term solution for town
19	Upgrade the distribution system, this is paramount..... find the money in the system. there is plenty of room.
20	I understand that upgrades are needed. The status quo is no longer a viable option.
21	Hydro one has more power interruptions than the old system
22	Sounds to me like someone in charge should have seen these things coming. When the shingles on a roof need replacing you can't just waste money patching the roof forever, and when the landlord replaces the shingles on the roof the tenants of the building shouldn't be burdened with the cost, the landlord should have prepared for this eventuality.
23	Not cost effective
24	Not practical or logical. Costlier in the long run.
25	maybe fund raising such as the hospital does
26	A degraded system will be costly in the long run.
27	No long term benefits. Increased cost to customers and increased debt for utility. System will eventually be useless.
28	need upgrades
29	We should try to be more proactive and a large unexpected cost when the system reaches life's end
30	It makes no economic or efficiency sense to keep the existing aging distribution.
31	look at other provinces, lower rates, why?
32	Time for upgrade
33	I don't like the idea of running the existing system to the ground and then having to shell out a large sum of money for a new system.
34	A la longue tout finirait par se briser

Question #37

Borrow the necessary funds to maintain existing aging distribution system. This will lower the distribution costs, but it will not help us reduce the cost of power. All this will do is keep our current system working while adding debt to the utility.		
Answer Options	Response Percent	Response Count
Yes	21.1%	32
No	78.9%	120
Reason:		35
	answered question	152
	skipped question	27

Number	Reason:
1	upgrade system, long term investment
2	The system needs to be upgraded.
3	As above
4	The energy we use everyday must be maintained and progressively acquired through as efficient a system as possible
5	Don't understand
6	don't borrow, to much interest to pay, which will more than likely fall on the consumer, sooner or later and would cost more to the consumer if not fixed properly
7	Even though it is a better option than the first one, but old and inefficient system would still be a problem.
8	- waste of money
9	-makes no sense to pour good money after bad!
10	See above
11	Do a big investment to fix all the problems and increase the cost of electricity on several years.
12	prepare for future
13	the infrastructure simply needs to be upgraded. We live in the 21st century.
14	You are asking questions that few clients will have enough info to make a decision.
15	Although it is nice to lower distribution costs, adding debt to the utility is not ideal.

16	The debt will continue to grow and become unmanageable. It is folly to maintain an aging system which may well become totally ineffective and possibly obsolete.
17	Ineffective, not a solution to reduce future costs.
18	Also, not a proactive approach
19	not ideal long-term solution for town
20	dumping the costs on the next generation is stupid... that is why the costs are out of control now.
21	I don't like the thought of debt when Hydro rates are in flux due to the Liberals trying to curry favour.
22	Adding debt with no benefit seems wasteful
23	Please don’t copy the Provincial “No Wynn strategy"
24	Completely counter productive. Does not fix the aging system, only band-aids the problem.
25	maybe find the lowest interest cost or grant from the government
26	Status quo does not prepare for the future.
27	Throwing good money after bad.
28	No long-term benefits here either. Just more debt and an aging system that will become useless.
29	Better product for the customer
30	current system needs upgrade
31	It is not economically wise to borrow on a system that is degrading. Besides we don't need more debt.
32	' "
33	It doesn't make sense to me to borrow money to keep an old system working, when we can possibly finance an upgrade that will potentially decrease our monthly bills instead o adding debt to the utility.
34	Le taux d'intérêt serait à durée du terme trop haut
35	Je ne peux absorber une augmentation

Question #38

Finance the investment in an upgrade of the existing aging distribution system through a slight increase in our distribution rates. If we increase the cost of distribution slightly (by 2%), we will be able to reduce energy losses by 10%. This potentially could result in an overall reduction of your bill every year after the initial investment by reducing our power costs. This would also increase the value of the utility to the town.		
Answer Options	Response Percent	Response Count
Yes	80.3%	122
No	19.7%	30
Reason:		52
	answered question	152
	skipped question	27

Number	Reason:
1	interest rates are at the lowest at this time, perhaps the township should look at financing from the sale of Bonds.
2	Sounds like a good start.
3	Throwing money away
4	This appears to be the most cost-effective option at the least cost to the consumer.
5	Be better for all in the long run
6	The 10% losses how much would that represent in money? also is this line loses or a total loss overall?
7	no brainer
8	Don't understand sorry
9	May help with the power surges.
10	Best long-term decision.
11	The 2% increase could hopefully be offset by higher reduction of rates after upgrades are completed
12	we need some need reductions to help

À certain percentage should have been put aside for years and not wait until the last minute to start
hiking prices. And upgrading would not enough to get a better system. Let's use the new
13 technologies available
This seems like the best option as it could result in lower bills (which are outrageously high now),
14 while reducing energy losses.
15 Makes the most sense
16 - this would help with future power consumption and rates
Obviously, we need to upgrade, but are cost increases the only option? Have we explored all
17 avenues?
A very small increase is understandable to upgrade the system but more than 2% and people
18 especially the elderly on a fixed income will not be able to afford their energy bills
Investment in an upgrade that will result in reduced energy losses, power costs and adding value to
19 the utility to the town seems the most logical option for the future.
20 This is the most reasonable option
21 I think we can handle a slight increase to reduce energy loss and increase the utility to the town.
22 makes sense
Any decision that result in increased costs passed on to clients who pay terrible costs already is
23 unacceptable. Hydro rates are already too high.
I'm not a fan of higher distribution rates, but if it is going to add value to the town, i think it will be
24 beneficial to future generations.
As long as the increase does not become a great burden and is subject to review and correction this
appears to be the most sensible approach. Unfortunately---Hydro 1 is involved with the service and
25 they are and have been mismanaged and responsible for unduly high and unaffordable rates.
Spend a little more now to be able to save in the future. Budgeting would have to be key. Going over
26 budget could mean more than a 2% increase which would then decrease future returns.
This is a proactive approach however the costs of the upgrades should be taken from the profit being
through the current rates and not by billing the expense to the existing customer base. I own a
house and I do not ask the bank to pay for my home improvements, I must budget for those and take
27 the funds from my savings.
28 Seems the most plausible & efficient.
29 makes good business sense
30 this sounds like good economics. Why was this not done long ago?
31 upgrading is essential, but the town people cannot be burdened too much with cost
32 This is the fiscally sound and responsible option.
33 Increase the value of the utility to the town
Taking proactive steps to increase reliability and reduce line loss is a good idea, but somebody has
to pay for it. I don't think it should be a shared responsibility between CPUC and its customers. As a
customer I feel I already pay for distribution and that as a responsible business CPUC should be
34 using that money to provide the best service they can. Upgrading the system before a catastrophic

failure seems like the smart thing to do, throwing more and more money at an aging system that is outdated and unreliable is not a sound business practice. I realize that CPUC is in it for the money, but I think that their business plans should have accounted for eventual upgrades and not have to putt extra burdens on its customers.

35 Short term pain, for long term gain...looks to the future, proactive, benefits over time

36 sounds good pay a little bit now

37 i think a small increase would be worth it, if it is going to reduce our power cost in the long run.

38 2% is reasonable.

39 This is the best option. A small increase at present will have good long-term benefits.

40 Most reasonable less impacts overall

41 I see this as best option

42 long term goal

43 It makes sense to upgrade. In the end it will pay off.

44 This seems to be the most reasonable solution, we absorb the initial increase in rates but with the expectation of higher savings down the road, providing of course that the Corporation does not keep raising the rates.

45 We can't keep putting band aids on the system.

46 ' "

47 if the upgrade is adequate and the distribution cost not more than 2% increase.

48 To keep our utility in our town

49 As long as the savings are passed on it shows It would be fair

50 Sounds like the most reasonable way but the wording of the other options makes them seem less desirable... I'm not sure.

51 If it means lower bills in the future and adding value to the town, I think this is the best option.

52 We lose service very often so if you can improve this by 10% I wouldn't mind paying more on my monthly fees if it means I hope loose power when they're is the smallest rain or snow storm outside.

Question #39

We take proactive steps to modernize the existing, aging system, reducing line losses and improving reliability. However, without increasing the rates or borrowing, this will likely put our utility in distress financially.		
Answer Options	Response Percent	Response Count
Yes	34.9%	53
No	65.1%	99
Reason:		30
answered question		152
skipped question		27

Number	Reason:
1	Our utility is already in financial distress.
2	Being fiscally responsible for future generation
3	Probably not sure
4	Why should the costumer pay more? The utility has assets and makes money. It should pay for its own repairs/upgrades. It may have a lower net worth next year, but it won't be taking advantage of its customers. A restaurant buys equipment as need; however, it does not raise its prices constantly. I mechanic needs to buy new tools regularly; however, it does not raise its shop rate constantly, etc. The utility is making money, so it should invest that money as need.
5	we need new infrastructures, old will cost even more in the future
6	Any homeowner knows that some increases are sometimes necessary in order to get a better service.
7	- need to move forward - aging infrastructure will not benefit us
8	Businesses already feel the crunch with hydro costs...increases make it more difficult on business owners, seniors and lower income families.
9	Every time we improve service, it means cost, and cost is paying more for electricity.

10 can't go into too much debt
Again - any increases to our hydro bills not
11 acceptable.
I think increasing the rates is what needs to happen to avoid
12 financial distress.
Hydro rates have doubled in the past ten years. Enough
13 is Enough.
Financial distress on the system is not a viable option nor is borrowing. A modest distribution increase seems the most practical---
14 however distasteful it may be
Money doesn't grow on trees; the town cannot afford to
15 upgrade on its own.
This is the responsible thing to do, plan for upgrades by saving some of the
16 profits being made.
this is necessary. someone has to pay for it. we should
17 all pony up
No more borrowing... increase rates if necessary... work
18 more efficiently...
It doesn't make sense to place the utility in a precarious financial situation. You have to
19 pay to play.
Taking proactive steps to increase reliability and reduce line loss is a good idea, but somebody has to pay for it. I don’t think it should
be a shared responsibility between CPUC and its customers. As a customer I feel I already pay for distribution and that as a
responsible business CPUC should be using that money to provide the best service they can. Upgrading the system before a
catastrophic failure seems like the smart thing to do, throwing more and more money at an aging system that is outdated and
unreliable is not a sound business practice. I realize that CPUC is in it for the money, but I think that their business plans should have
20 accounted for eventual upgrades and not have to putt extra burdens on its customers.
Quick fix that won't be
21 sustainable
try to keep the cost down by trying to find ways to lower
22 the cost
Increase rates to fund the investment. What is the projected rate increase? What are the long-term benefits of modernization (return
23 on investment)?
This is a bad time to increase
24 debt.
No use becoming financially
25 distressed.
26 can't afford it
27 ' "
but the population cannot take an increase on their bill. How many hydro bills do you
28 have outstanding?

29	It obviously sounds better to modernize an existing system without raising rates, but it is not logical as again, it puts the utility in debt.
30	Ce n'est pas une bonne idée pour la compagnie ce qui serait difficile pour continuer dans son domaine

Question #40

How important is it for Chapleau to take action to improve the delivery of continuous, reliable power? (on a scale of 1 to 10, 1 being not at all and 10 being extremely important)		
Answer Options	Response Percent	Response Count
1	0.0%	0
2	0.0%	0
3	0.0%	0
4	1.3%	2
5	9.9%	15
6	2.6%	4
7	9.2%	14
8	22.4%	34
9	7.9%	12
10	46.7%	71
Please explain:		48
	answered question	152
	skipped question	27

Number	Please explain:
1	commodity we can’t do without
2	People need to look into other methods such as solar and wind energy.
3	while C P R is operating from Chapleau the majority of residents are employed and even the older residents have reasonable monthly incomes that wo
4	I'm on the 'bad' half where my power goes off and on again several times a week. Hard on appliances and ruined my computer. Now I have a battery ba
5	Having hydro is important, we rely on it for so many reasons and heat in the winter months is at the top of the list for me, think of our seniors.
6	We must improve and retain ownership of PUC
7	Not sure
8	Electricity is a necessity in this day and age
9	Hydro is very important for all residents, businesses and the lumber mill.

10 the infrastructures in place right now needs to be brought up to todays demands for power
11 We are in a remote area and require this service for safety and survival.
12 -line losses and unreliable service will affect everyone- I would like to see many options explored in depth before making any decision.
13 We need reliable power but not if the costs are going to rise to the consumer, we can't afford any higher bills
14 The people of Chapleau depend on electricity from the town.
15 We all need access to reliable power
16 Well electricity is an important source of energy when that it all we rely on.
17 Any raise in costs to the consumer is unacceptable. Action that does not result in costs to already too high costs is unacceptable.
18 Power is invaluable to most homeowners, without it they would be unable to do many necessities.
19 In order to ensure the continuance of CPUC as it stands now--these changes are necessary to prevent the take over by Hydro 1 and at the same time im
20 Generally, on our street we don't experience loss of power often however, i hear other places in town it occurs often.
21 Plan for the future
22 everyone needs reliable power
23 we need reliable power.
24 cannot keep old equipment, must upgrade
25 If you don't have reliable power, people, institutions and businesses suffer.
26 We all rely on hydro
27 10 it is very important.
28 If something isn't done the system will fail.
29 We need power to maintain heat, food preservation, etc. Besides we will not see the Premier delivering food baskets in our town,
30 Keeping control of our service and utility in the hands of our community is important for decisions being made which affect us directly. Not in favour of lo
31 for the resident of Chapleau
32 the delivery of continuous and RELIABLE power is important to our community
33 For Chapleau, it is among the highest priorities, equal to modernizing Township infrastructure for water and sewage.
34 It is important to make improvements but equally important to avoid increasing debt. Think of Ontario Hydro's debt that never went away.
35 We need the delivery of continuous, reliable power to operate as a community and there is no time like the present to invest in improving the system.
36 Not 100% sure, this is mostly Chinese to me
37 reliability is very important
38 I feel it is somewhat reliable so until there are more issues than I would rate it higher.
39 We rely on electrical power for most of our services, i.e. heat, electrical appliances, technology etc. Our infrastructure would crumble without electrical p
40 ' "
41 we do not want hydro one to take over
42 Important! As the system continues to age, future problems will arise.
43 We don't want hydro one
44 Can't have power outages because of unreliable system, we need hydro
45 I feel it is currently pretty reliable (I must be in the newer area)

46	POUR QUE LE TAUX NAUGMENTE PAS TROP
47	Quand tout est désuet il faut le changer pour plus de performance
48	We lose power often, even when it's the smallest snow or rain storm. and it doesn't come back for a long time sometimes even when the storm has pass

Question #41

Would you say that Chapleau Public Utilities Corporation (CPUC) is a respected company in the community?		
Answer Options	Response Percent	Response Count
Yes	88.8%	135
No	1.3%	2
Do not know	9.9%	15
	answered question	152
	skipped question	27

Question #42

Would you say that CPUC is easily accessible?		
Answer Options	Response Percent	Response Count
Yes	92.1%	140
No	0.0%	0
Don't know	7.9%	12
	answered question	152
	skipped question	27

Question #43

In general, how would you rate CPUC's overall performance in serving you?		
Answer Options	Response Percent	Response Count
Excellent	50.7%	77
Good	44.1%	67
Fair	4.6%	7
Poor	0.7%	1
	answered question	152
	skipped question	27

Question #44

Please provide your contact information to participate in the draw for a $500 credit on your hydro account. The draw will take place May 17-17, and the winner's name will be posted on our website.		
Answer Options	Response Percent	Response Count
Name	100.0%	149
Email Address	91.3%	136
Telephone	96.6%	144
	answered question	149
	skipped question	30

Appendix F Newsletter

Dear Chapleau Public Utilities Customers:

Chapleau PUC is applying to the Ontario Energy Board to change its electricity distribution rates effective May 1, 2019. If the application is approved, a typical residential customer of Chapleau PUC will see an increase of approximately $4.90 per month and a typical General Service < 50kW customer of Chapleau PUC will see an increase of approximately $24.27 per month.

The application which will be filed on August 31, 2018, is called a "Cost of Service" and involves setting rate based on the value of the utility's assets and the cost incurred in providing service to its customers. For Chapleau PUC, this involves the maintenance and service of one transformer stations with two transformers, poles, lines, transformers, and meters. All wages and material related to the distribution of power form the basis for the costs included in the application. Chapleau PUC's last Cost of Service application was in 2012.

Chapleau PUC recently changed its corporate structure when on January 1, 2018, it merged with Chapleau Energy Services to become one company. The merger is intended to reduce regulatory complexity and administrative burden and to make rate applications a less difficult process. The result is a company that can better control the costs associated with rates, and increased transparency.

Operating costs have increased by approximately $150,000 over the past five years. The major contributing factors include:

- An increase in outside services for regulatory requirements.
- Wage increases for succession planning.
- Increased depreciation expense related to the purchase of a new utility truck.
- Costs associated with the merger of the two companies including the transfer of 100k in assets.
- Reduction in revenue offsets related to Hydro One's reducing CPUCs service to 911 emergencies only.

The net result for residential customers will be an average of $4.90 per monthly bill, with a typical monthly bill averaging $121.13. This rate increase will impact approximately 1,100 residential customers.

A full slide presentation is available on our website at

http://www.chapleau.ca/en/townshipservices/publicutilities.asp

Chapleau PUC is looking for feedback from its customers. Please email the CPUC at puc@chapleau.ca, comment on our Facebook page or Twitter, or drop into our office at 110 Lorne Street South between 8:30 am and 4:30 pm, Monday to Friday.

The first 80 responders will receive a free retractable clothesline (CPUC customers only).

Appendix G PDF of List of Approvals

File Number:	EB-2018-0087
Exhibit:	1
Tab:	
Schedule:	
Page:	Appendices
Date:	31-Aug-18

Appendix 2-A
List of Requested Approvals

The distributor must fill out the following sheet with the complete list of specific approvals requested and relevant section(s) of the legislation

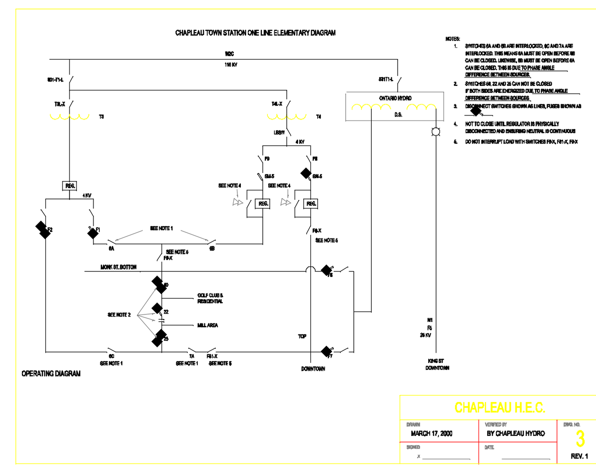
Additional requests may be added by copying and pasting blank input rows, as needed.

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

Chapleau Public Utilities Corporation is seeking the following approvals in this application:

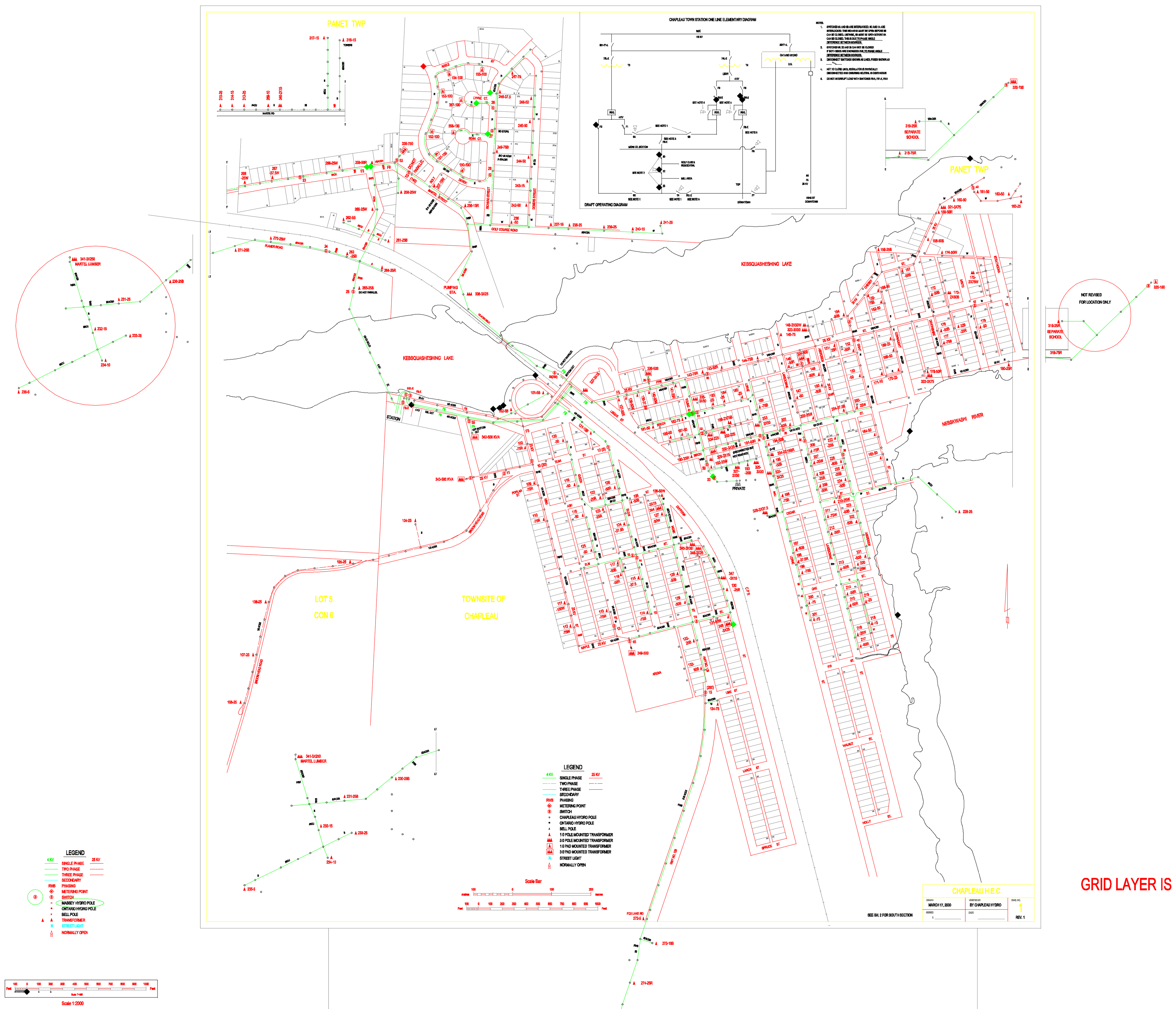
1		Approval to charge distribution rates effective May 1, 2019 to recover a service revenue requirement of $1,004,820 which includes a revenue deficiency of $221,259 as detailed in Exhibit 6. The schedule of proposed rates is set out in Exhibit
2		Approval of the Distribution System Plan as outlined in Exhibit 2 Section 2.5.2
3		
4		Approval to adjust the Retail Transmission Rates – Network and Connection as detailed in Exhibit 8.
5		Approval of the proposed loss factors as detailed in Exhibit 8.
6		Approval to continue to charge Wholesale Market and Rural Rate Protection Charges approved in the Board Decision and Order in the matter of CHEI 2017 Distribution Rates (EB-2016-0062).
7		Approval to continue the Specific Service Charges, Retail Service Charges, as approved in the Board Decision and Order in the matter of CPUC's 2015 Distribution Rates (EB-2014-0063).
8		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.
9		Approval to dispose of balances in the LRAMVA (1568) and Conversion form CGAAP to MIFRS (1576) variance account as presented in Exhibit 9.
10		Such other approvals that CPUC may request and that the OEB accepts.

Appendix H Map of Service Area

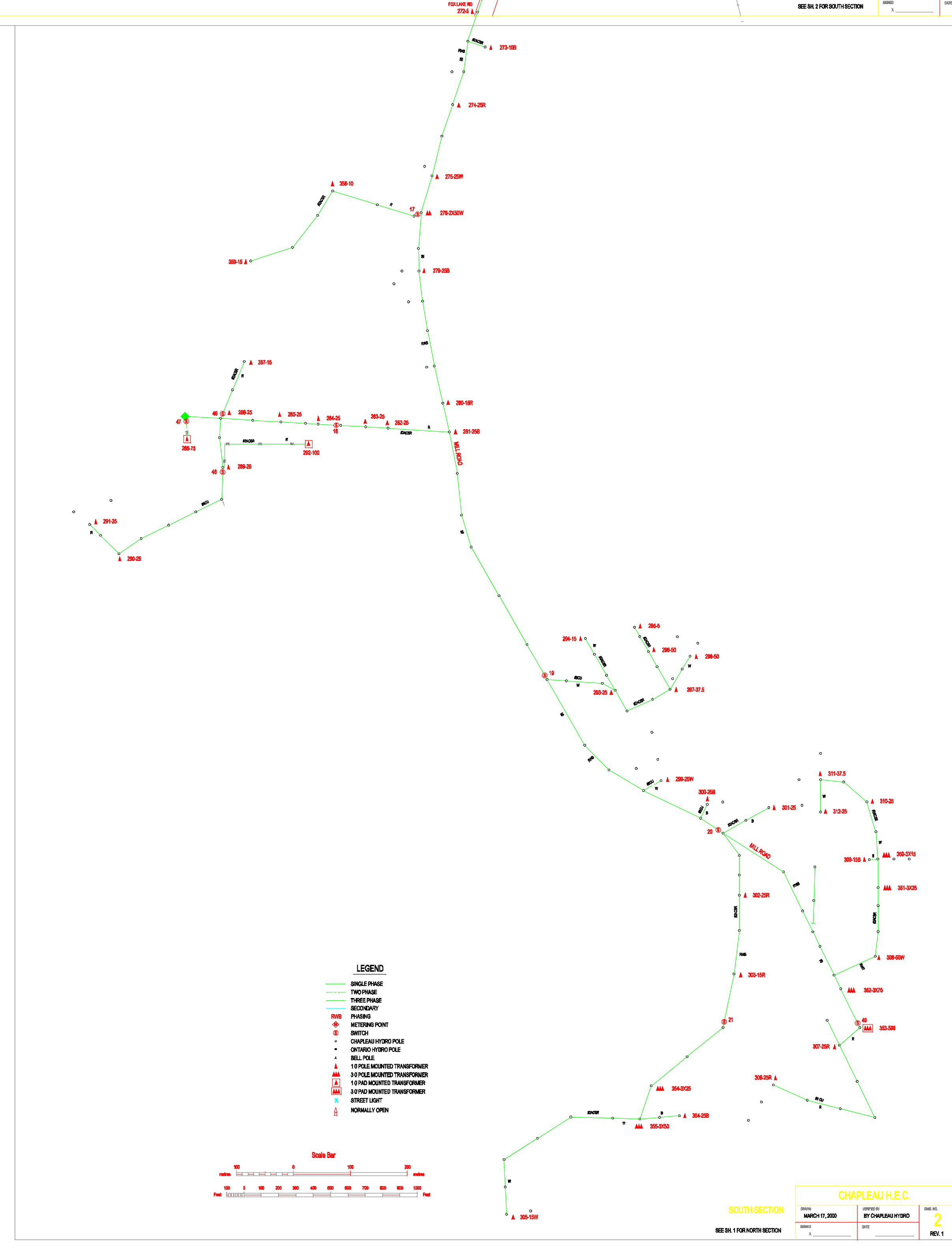


17" X 22"

PLOT 1"= 123'



GRID LAYER IS FROZEN



CHAPLEAU

PLOT
1"=215

13 HRS

15 HRS

15 HRS

22 HRS

Appendix I Community Profile (Town of Chapleau)

Community Profile

2018

Chapleau

V 2.0
May 2018

Information in this document is subject to change without notice. Although all data is believed to be the most accurate and up-to-date, the reader is advised to verify all data before making any decisions based upon the information contained in this document.
For further information, please contact:

Township of Chapleau
20 Pine Street W, PO Box 129
Chapleau, ON
P0M1K0
Phone: 705-864-1330
Web: www.chapleau.ca

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Business Directory Available Online

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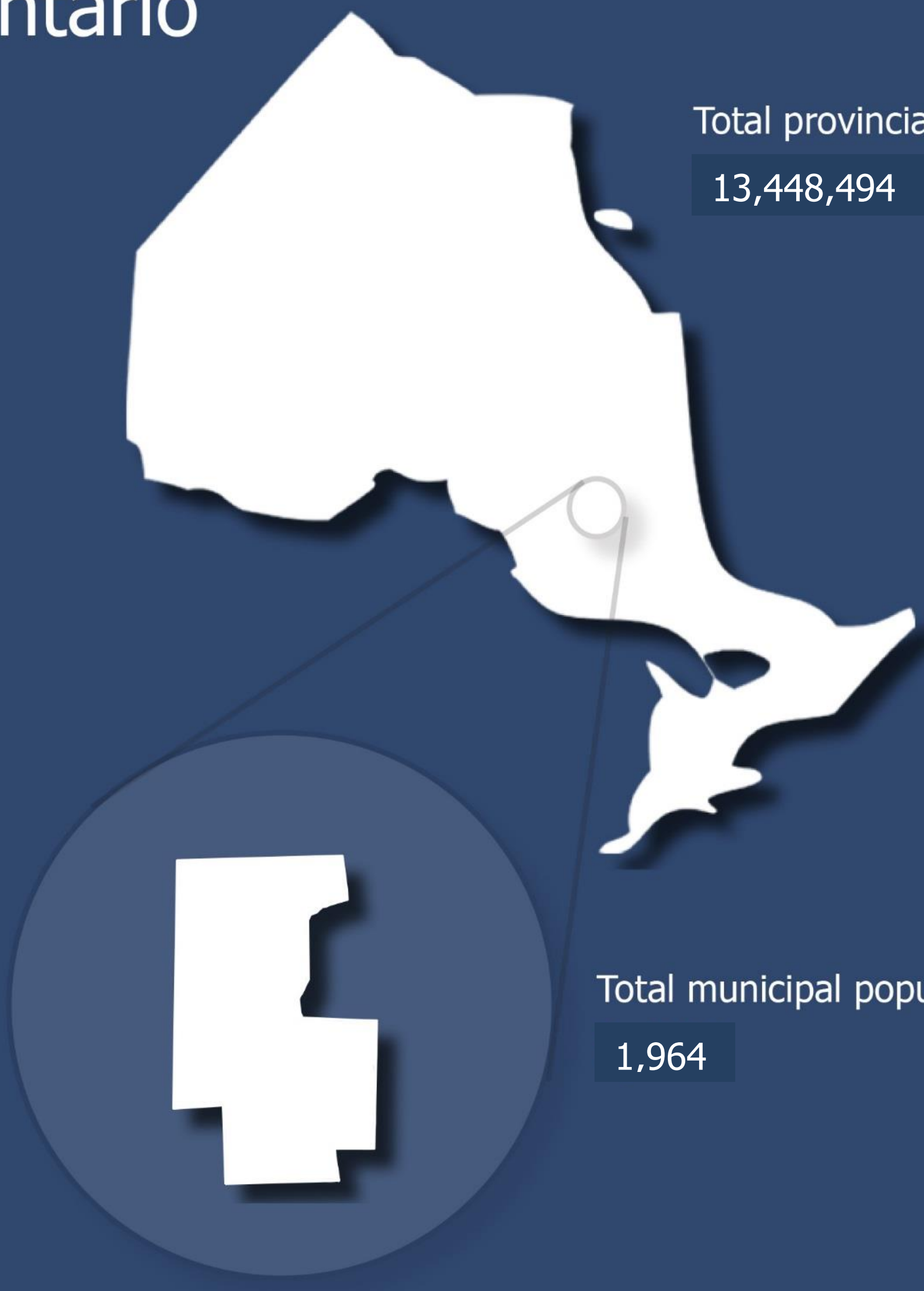
Township of Chapleau

Geographic:

The Township of Chapleau is situated within the Boreal Forest and Arctic Watershed Region of Northern Ontario. Chapleau is best known for being the home of the world's largest Crown Game Preserve: 700,000 hectacres.

Ontario



Total provincial population:

13,448,494

Total municipal population:

1,964

Township of Chapleau

McSWEENEY
inspiring economic sustainability

Demographic:

Chapleau has a population of 1900+. Residents in Chapleau are less likely to change places of residence in the five year category, compared to the Province. Estimates indicate people moving to Chapleau tend to be relocating from other parts of Ontario as opposed to moving from outside of the province or country.

47.9% French & English Bilingual

47 Median Age

Average value of dwelling $ 119,358

Mobility 15% Residents that had moved within the previous year

Mobility 36% Residents that had moved within the previous 5 years

50% 50%

Population by Gender

McSWEENEY
inspiring economic sustainability

Labour Force:

Chapleau is home to a labour force of 1,650 people. Median income levels are higher than the provincial average.

Participation	60.3%
Employment	53.9%
Unemployment	10.6%

Median income

$36,816

Average income

$44,022

Key Sectors by Industry

- Transport and warehousing
- Manufacturing
- Retail trade
- Agriculture, forestry, fishing and hunting
- Health care and social assistance

Key Sectors by Occupation

- Trades, transport and equipment operators and related
- Natural resources; agriculture and related production
- Business, finance and administration
- Education; law & social; community & government services

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inspiring economic sustainability

1 Introduction

The Township of Chapleau is situated within the Boreal Forest and Arctic Watershed Region of Northern Ontario. Chapleau is best known for being the home of the world's largest Crown Game Preserve, as well as being the 2011 winners of WFN's Ultimate Fishing Town Canada contest. The Game Preserve, established in 1925, is 700,000 hectares in size, making it an exciting eco-tourism destination for world nature and wildlife travelers.

Chapleau is also home to many different cultural communities, such as Chapleau Cree First Nation, Chapleau Ojibwe First Nation, Brunswick House First Nation, Chapleau's francophone community and Chapleau's Metis community. All of the various cultures have had a large impact on the history and upcoming of Chapleau.

Deeply rooted in the fur trade and the railway, Chapleau's history began in 1885 when the Canadian Pacific Railway line provided access for the Hudson's Bay Company Trading Post. A fire in 1948 encouraged the government to develop a road so that logging contractors could remove the timber before it rotted. Consequently, Highway 129 was completed during the depression. In future years, Highways 101 and 17 were constructed to link Chapleau with Timmins to the East, and Wawa to the West (Wawa - 140 kilometres to the West and Timmins 200 kilometres to the East).

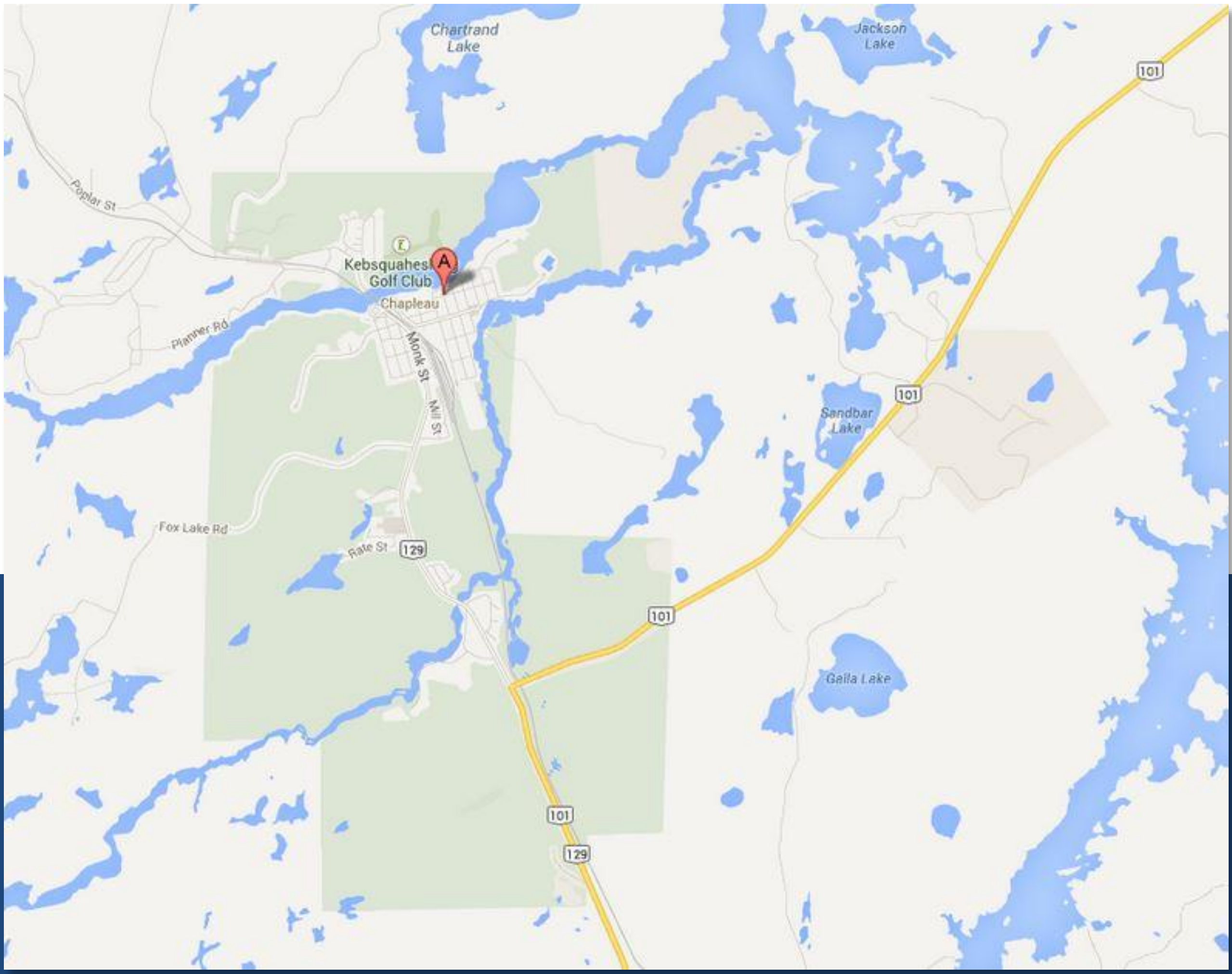
Chapleau offers beautiful land to be utilized however you wish - ATVing, canoeing, kayaking, hiking, bird watching, biking, swimming, fishing, hunting, boating, etc. If you're looking for the ultimate outdoor adventure, come to the beautiful Chapleau Region for an unforgettable experience!

1.1 Location

Chapleau is linked to larger communities, such as Timmins and Sault Ste. Marie, via highway 101, and to Sudbury via highways 129 and 17. The Budd Car, operated by Via rail, offers train service travelling alternately east to Sudbury or west to White River with daily stops in Chapleau. Travellers and residents can reach southern Ontario by Via Rail on the Canadian National Railway which stops regularly in Foleyet, which is one hour from Chapleau.

International travel can be accommodated at Toronto Pearson international airport, with connecting regional air service to Timmins, Sault Ste. Marie, and Sudbury. Chapleau operates a municipal airport that is used for emergency services, and is host to the Ministry of Natural Resources base, which is used for fire suppression water bombers.

Figure 1: Chapleau Location Map



Source: Google Maps, http://bit.ly/1bVf07M

1.2 Climate

Chapleau derives climatic data from the NAV Canada staffed weather station at the Chapleau Airport.

Table 1: Chapleau Average Temperature (°C)

Temperature	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Daily Average	-15.6	-13.2	-7.1	1.7	9.5	14.8	17.2	15.9	11.2	4.2	-3.2	-11.2
Standard Deviation	3.5	3.1	2.6	2.4	2.3	1.5	1.2	1.3	1.6	1.6	2.5	3.7
Daily Maximum	-9.3	-6.4	-0.2	8.0	16.3	21.4	23.4	21.9	16.6	8.8	0.8	-6.0
Daily Minimum	-21.9	-20.0	-14.0	-4.7	2.6	8.3	10.9	9.9	5.8	-0.4	-7.2	-16.5
Extreme Maximum	5.8	10.5	20.9	30.0	33.7	**36.5**	35.0	34.0	31.1	25.5	18.6	22.0
Extreme Minimum	**-50**	-43.5	-41.5	-24.0	-9.5	-6.0	-3.0	-1.0	-7.5	-17.0	-31.0	-42.0

Source: Environment Canada, Chapleau Weather Station. * This station meets WMO standards for temperature and precipitation. http://bit.ly/16f5Gvq

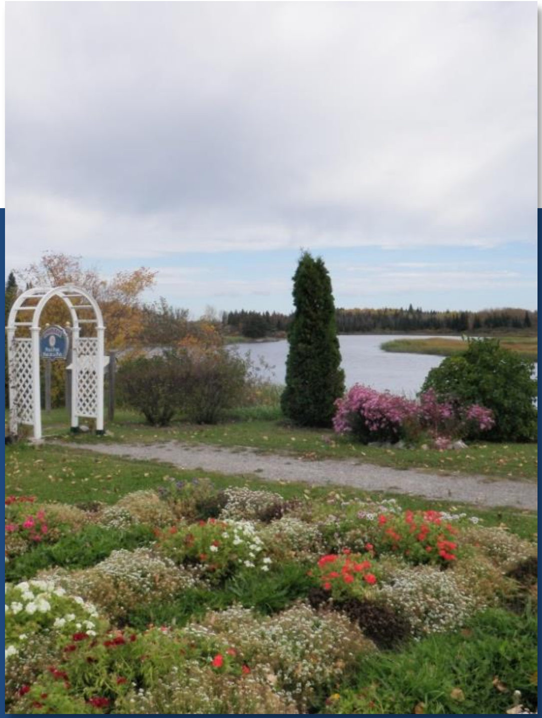
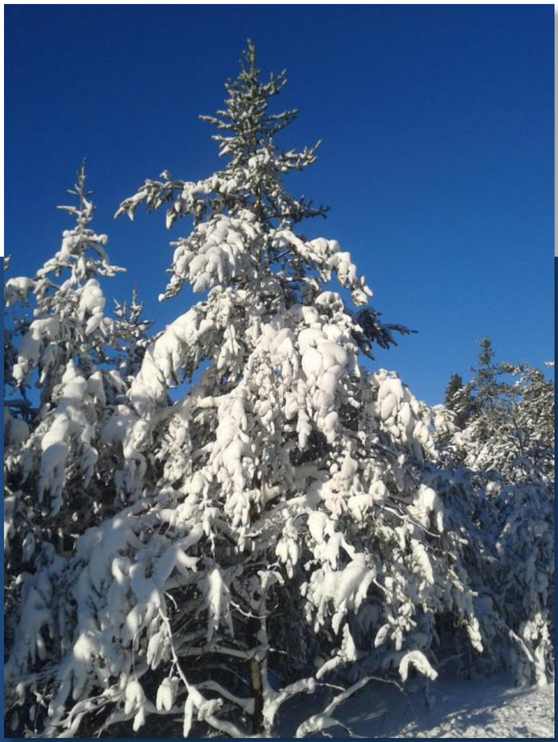


Table 2: Chapleau Average Precipitation

Precipitation	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Rainfall (mm)	2.0	1.8	12.7	28.7	66.0	80.3	82.2	76.0	94.7	71.0	24.0	5.9
Snowfall (cm)	55.6	45.6	36.6	23.4	3.8	0.0	0.0	0.0	0.3	11.5	42.2	62.7
Precipitation (mm)	51.9	42.9	46.9	52.7	69.9	80.3	82.2	76.0	95.1	83.1	64.4	63.7
Extreme Daily Rainfall (mm)	18.0	12.4	21.0	34.2	47.0	**82.6**	53.4	56.0	71.8	61.7	28.6	17.4
Extreme Daily Snowfall (cm)	31.0	**39.0**	31.0	33.4	22.0	0.0	0.0	0.0	3.4	19.6	33.0	36.5
Extreme Daily Precipitation (mm)	31.0	29.4	31.0	36.4	47.0	**82.6**	53.4	56.0	71.8	61.7	35.8	36.4
Extreme Snow Depth (cm)	113	116	**132**	115	80	0	0	0	1	21	35	60

Source: Environment Canada, Chapleau Weather Station. * This station meets WMO standards for temperature and precipitation. http://bit.ly/16f5Gvq



2 Demographics

2.1 Population Size and Growth

Table 3: **Population Change**

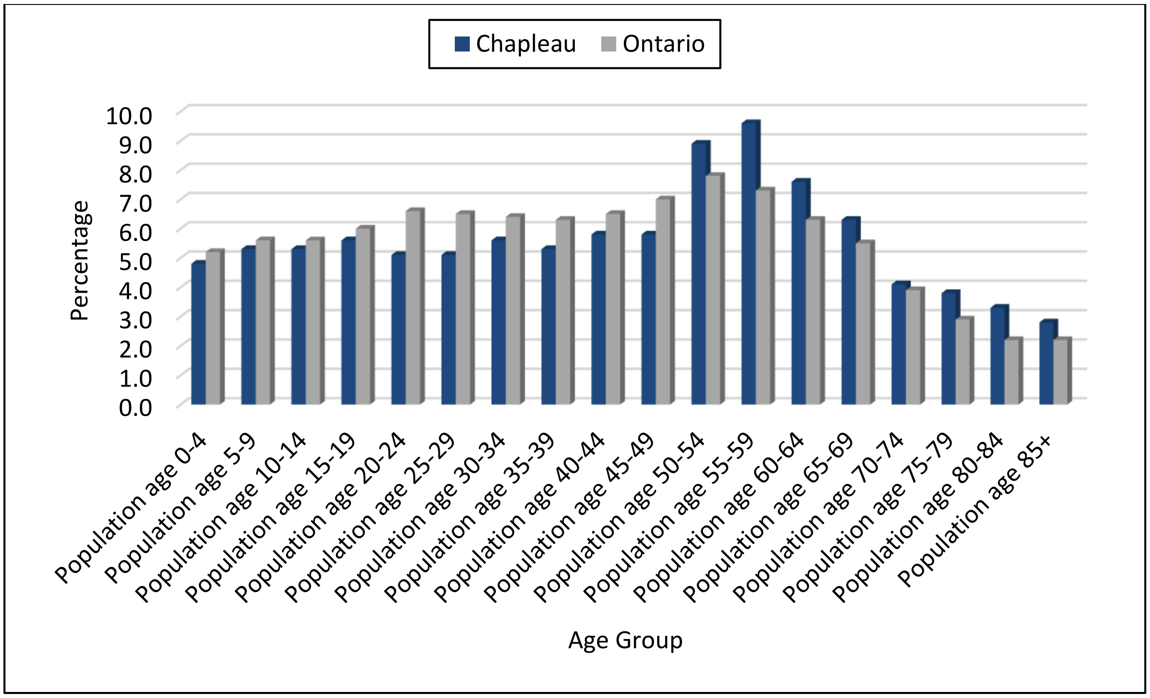
	2001	2006	2011	2016
Chapleau Population Count	2,832	2,354	2,116	1,964
% Change from Previous Census	-3.5	-16.9	-10.1	-7.2
	2001	**2006**	**2011**	**2016**
Ontario Population Count	11,410,046	12,160,282	12,851,821	13,448,494
% Change from Previous Census	6.1	6.6	5.7	4.6

Source: Statistics Canada 2001, 2006, 2011 and 2016

2.2 Age Profile

In 2016, Chapleau had a slightly older population compared to the provincial average. The median age in the township was 47.2, compared to 41.3 in Ontario, and the average age was 44 compared to the provincial figure of 41.

Figure 2: Age Distribution Chart, 2016



Source: Statistics Canada, 2016

Table 4: Age Distribution

Characteristics	Chapleau 2016	Chapleau 2016 (%)	Ontario 2016 (%)
Age	1,965	100.00	13,448,495
0 to 4 years	95	4.8	5.2
5 to 9 years	105	5.3	5.6
10 to 14 years	105	5.3	5.6
15 to 19 years	110	5.6	6.0
20 to 24 years	100	5.1	6.6
25 to 29 years	100	5.1	6.5
30 to 34 years	110	5.6	6.4
35 to 39 years	105	5.3	6.3
40 to 44 years	115	5.8	6.5
45 to 49 years	115	5.8	7.0
50 to 54 years	175	8.9	7.8
55 to 59 years	190	9.6	7.3
60 to 64 years	150	7.6	6.3
65 to 69 years	125	6.3	5.5
70 to 74 years	80	4.1	3.9
75 to 79 years	75	3.8	2.9
80 to 84 years	65	3.3	2.2
85 years and over	55	2.8	2.2

Source: Statistics Canada, 2016

2.3 Language Characteristics

Table 5 indicates 47.9% of people in Chapleau identify as bilingual, a much higher percentage than Ontario.

Table 5: Language Characteristics, 2016

Characteristics	Chapleau	Chapleau (%)	Ontario (%)
Total population	1940	100	13,622,941
English only	905	46.6	86.3
French only	90	4.7	0.3
English and French	930	47.9	11.0
Neither English nor French	15	0.7	2.4

Source: Statistics Canada 2016.

2.4 Mobility Characteristics

Residents in Chapleau are less likely to change places of residence in the five year category, compared to the Province. Estimates indicate those moving to Chapleau tend to be relocating from within Ontario rather than outside of the province or country.

Table 6: Chapleau Mobility Rates

Characteristics	Chapleau 2016	Chapleau 2016 (%)	Ontario 2016 (%)
Mobility status – place of residence one year ago			
Total population 1 year and over[1]	1,930		13,106,990
Non-movers[2]	1,640	84.9	87.5
Movers[3]	290	15.0	12.4
Non-migrants[4]	200	10.3	7.2
Migrants[5]	90	4.6	5.3
Migrants within Canada	55	2.8	4.1
Migrants from outside Canada	35	1.8	1.2
Migrants within Ontario	55	2.8	3.5
Migrants from outside Ontario	0	0.0	0.5
Mobility status – place of residence status five years ago			
Total population 5 years and over	1,835		12,546,040
Non-movers	1,170	63.7	62.9
Movers	670	36.5	37.1
Non-migrants	425	23.1	20.3
Migrants	240	13.1	16.8
Migrants within Canada	210	11.4	12.4
Migrants from outside Canada	30	1.6	4.4
Migrants within Ontario	180	9.8	11.0
Migrants from outside Ontario	30	1.6	1.4

Source: Statistics Canada 2016

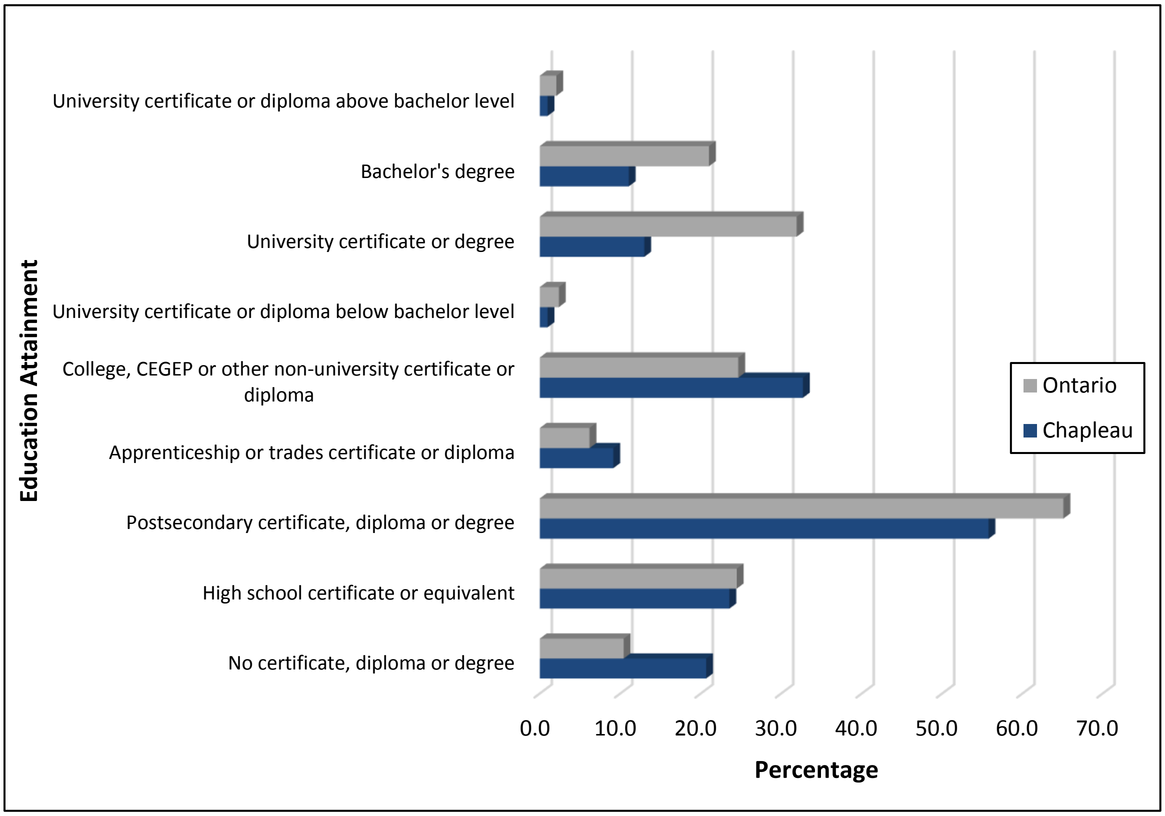
[1] Refers to the relationship between a person's usual place of residence on Census Day and his or her usual place of residence one year earlier. A person is classified as a non-mover if no difference exists. Otherwise, a person is classified as a mover and this categorization is called Mobility status (1 year ago). Within the category of movers, a further distinction is made between non-migrants and migrants; this difference is called migration status.
[2] Non-movers are persons who, on Census Day, were living at the same address as the one at which they resided one year earlier.
[3] Movers are persons who, on Census Day, were living at a different address from the one at which they resided one year earlier.
[4] Non-migrants are movers who, on Census Day, were living at a different address, but in the same census subdivision (CSD) as the one they lived in one year earlier.
[5] Migrants are movers who, on Census Day, were residing in a different CSD one year earlier (internal migrants) or who were living outside Canada one year earlier (external migrants).

2.5 Level of Education

Figure 3 and Table 7 indicate the level of educational attainment in Chapleau in 2016.

- Over 55% of Chapleau residents have a certificate, diploma or degree.
- The percentage of persons with an apprenticeship or trades certificate or diploma is higher than the Ontario average.
- The percentage of persons with College, CEGEP or other non-university certificate or diploma is higher than the Ontario average

Figure 3: Educational Attainment, 2016



Source: Statistics Canada 2016.

Table 7: Education Attainment, 2016

Characteristics[6]	Chapleau	Chapleau (%)	Ontario (%)
Total population 25 to 64 years by highest certificate, diploma or degree	1,040	100.0	7,229,120
No certificate, diploma or degree	215	20.6	10.4
High school certificate or equivalent	245	23.5	24.4
Postsecondary certificate, diploma or degree	580	55.7	65.1
Apprenticeship or trades certificate or diploma	95	9.1	6.2
College, CEGEP or other non-university certificate or diploma	340	32.7	24.6
University certificate or diploma below bachelor level	10	0.9	2.36
University certificate or degree	135	12.9	31.9
Bachelor's degree	115	11.0	21.0
University certificate or diploma above bachelor level	10	0.9	2.06

Source: Statistics Canada 2016

[6] By highest certificate, diploma or degree obtained.

2.6 Income

Table 8 indicates that, in 2015, the median total income level was slightly higher in Chapleau than in Ontario.

Table 8: Total Income Levels, 2015

Characteristic	Chapleau	Chapleau	Ontario (%)
Total population 15 years and over (by income 2015)	1,630	100.0	11,038,440
Without income	45	2.7	4.3
With income	1590	97.5	95.6
Under $10,000	200	12.3	14.6
$10,000 to $19,999	245	15.0	16.5
$20,000 to $29,999	225	13.8	12.8
$30,000 to $39,999	165	10.1	10.4
$40,000 to $49,999	140	8.6	9.2
$50,000 to $59,999	170	10.4	7.3
$60,000 to $69,999	140	8.6	5.7
$70,000 to $79,999	90	5.5	4.3
$80,000 to $89,999	60	3.7	3.4
$90,000 to $99,999	55	3.4	2.9
$100,000 and over	90	5.5	8.2
$100,000 to $149,999	85	5.2	5.4
$150,000 and over	15	0.9	2.8
Characteristic	**Chapleau**		**Ontario**
Median total income $	$36,816		$33,539
Average total income $	$44,022		$47,915

Source: Statistics Canada 2016.

Table 9: Family Income Levels, 2015

Characteristic	Chapleau	Ontario
Total number of economic families	590	3,689,580
Median family income $	88,960	91,089
Average family income $	97,810	115,328

Source: Statistics Canada 2016.

Table 10: Household Income Levels, 2015

Characteristic	Chapleau	Chapleau (%)	Ontario (%)
Total number of private households (by income in 2015)	870	100	5,169,175
Under $10,000	15	1.7	3.0
$10,000 to $19,999	60	6.8	6.2
$20,000 to $29,999	90	10.3	7.5
$30,000 to $39,999	70	3.3	7.9
$40,000 to $49,999	55	8.0	7.9
$50,000 to $59,999	65	7.5	7.5
$60,000 to $69,999	65	7.5	7.0
$70,000 to $79,999	70	8.0	6.5
$80,000 to $89,999	60	6.9	6.0
$90,000 to $99,999	45	5.2	5.5
$100,000 to $124,999	110	12.6	10.8
$125,000 to $149,999	70	8.0	7.6
$150,000 and over	90	10.3	16.4
Characteristic	**Chapleau**		**Ontario**
Median household income $	$72,128		$74,287
Average household income $	$80,594		$97,856

Source: Statistics Canada, 2016

3.1 Key Indicators

Chapleau is home to a labour force that is 1,650 persons strong. As illustrated in Table 11, Chapleau's participation and employment rates are slightly lower than Ontario. The unemployment rate is higher than Ontario.

Table 11: Labour Force Characteristics, 2016

Characteristic	Chapleau	Ontario
Total population, aged 15 years and older	1,650	11,038,440
In the labour force[7]	995	7,141,675
Employed	890	6,612,150
Unemployed	105	529,525
Not in the labour force	655	3,896,765
Participation rate %	60.3	64.7
Employment rate %	53.9	59.9
Unemployment rate %	10.6	7.4

Source: Statistics Canada 2016.

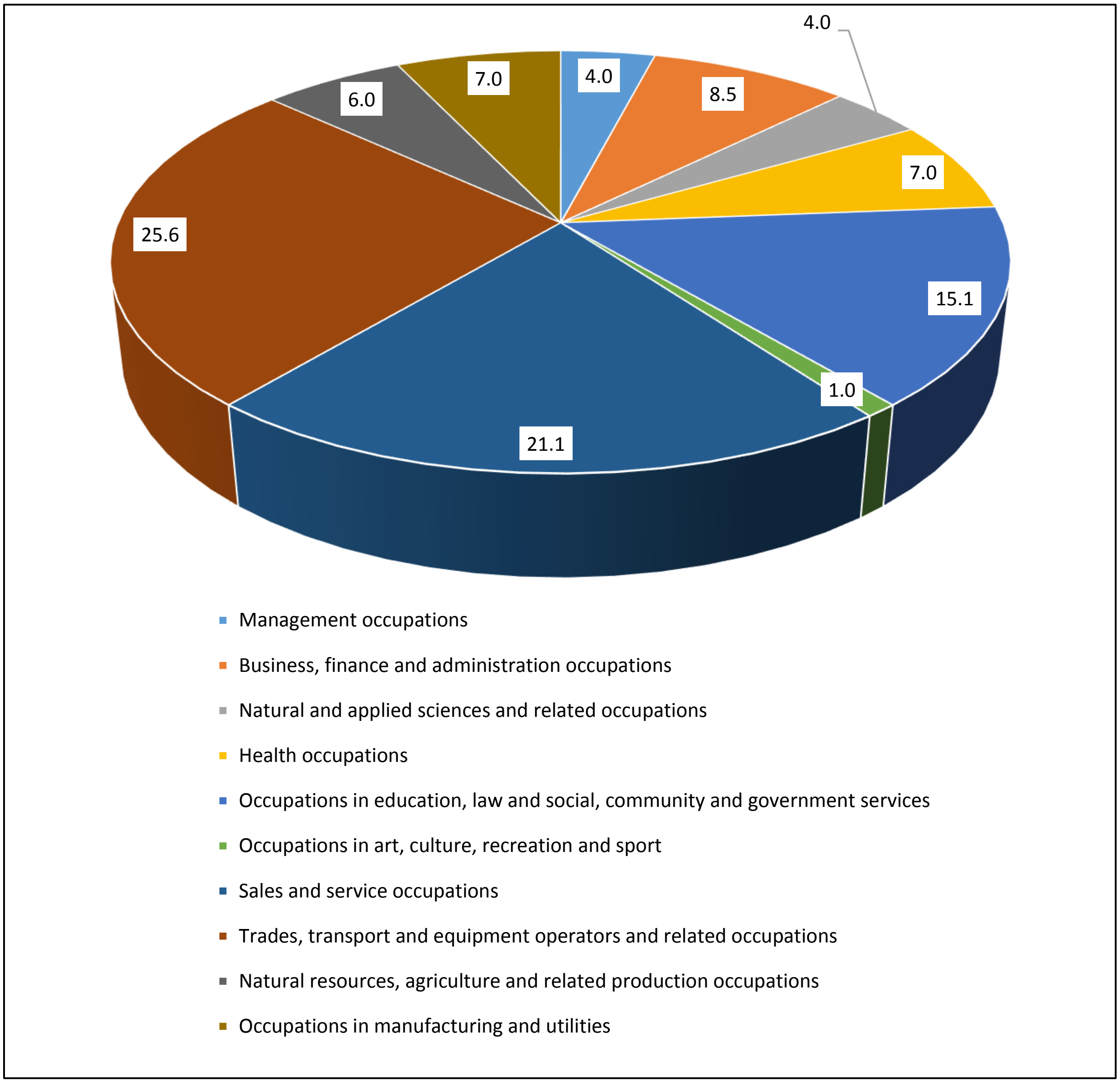
[7] Labour force - Refers to persons who were either employed or unemployed. Unemployed - Refers to persons 15 years and over, excluding institutional residents, who, during the week (Sunday to Saturday) prior to Census Day (May 16, 2006), were without paid work or without self-employment work and were available for work and either:
(a) had actively looked for paid work in the past four weeks;
(b) were on temporary lay-off and expected to return to their job;
(c) had definite arrangements to start a new job in four weeks or less.
Participation rate - Refers to the labour force expressed as a percentage of the population 15 years and over excluding institutional residents. Employment rate - Refers to the number of persons employed expressed as a percentage of the total population 15 years and over excluding institutional residents. Unemployment rate - Refers to the unemployed expressed as a percentage of the labour force.

3.2 Labour Force by Occupation

Figure 4 and Table 12 illustrate Chapleau's labour force make up by occupation:

- The Trades, transport and equipment operators and related occupations represent the largest occupational group (25.6%) in the community.
- The percentage of the labour force in Sales and service occupations (21.0%) is also substantial.

Figure 4: Labour Force by Occupation[8], 2016



Source: Statistics Canada 2016.

[8] Percentage calculated based on all occupations excludes occupation-not applicable.

Table 12: Labour Force by Occupation, 2016

Characteristic [9]	Chapleau	Chapleau (%)	Ontario (%)
Total labour force aged 15 years and over by occupation	995	100.0	7,549,583
Occupation - Not applicable	10	5.3	1.5
All occupations	985	94.7	98.4
Management occupations	40	8.0	11.2
Business; finance and administration occupations	85	15.4	16.6
Natural and applied sciences and related occupations	40	2.0	7.2
Health occupations	70	3.2	5.7
Occupations in education; law and social; community and government services	150	11.4	11.7
Occupations in art; culture; recreation and sport	10	0.0	3.0
Sales and service occupations	210	18.6	22.6
Trades; transport and equipment operators and related occupations	255	24.3	12.6
Natural resources; agriculture and related production occupations	60	5.2	1.6
Occupations in manufacturing and utilities	70	6.4	5.1

Source: Statistics Canada 2016.

[9] National Occupational Classification (NOC) 2016 – 25% sample data.

3.3 Labour Force by Industry

The largest percentage of labour force (by industry) in Chapleau is employed in the Transportation and warehousing industry, which accounts for 13.5% of the labour force compared to 4.6% for Ontario. The percentage of labour force in the Health care and social assistance industry (12.5%) and in the Manufacturing industry (11.5%) locally are also high.

The following table indicates labour force by industry:

Table 13: Labour Force by Industry, 2016

Characteristic [10]	Chapleau	Chapleau (%)	Ontario (%)
Total labour force 15 years and over by industry	995	100.0	7,141,675
Industry - Not applicable	10	1.0	2.4
All industries	990	99.5	97.6
11 Agriculture, forestry, fishing and hunting	85	8.5	1.4
21 Mining and oil and gas extraction	15	1.5	0.4
22 Utilities	15	1.5	0.7
23 Construction	45	4.5	6.6
31-33 Manufacturing	115	11.5	9.5
41 Wholesale trade	0	0.0	3.8
44-45 Retail trade	100	1.0	10.9
48-49 Transportation and warehousing	135	13.5	4.6
51 Information and cultural industries	15	1.5	2.4
52 Finance and insurance	10	1.0	5.3
53 Real estate and rental and leasing	10	1.0	2.0
54 Professional, scientific and technical services	15	1.5	7.9
55 Management of companies and enterprises	0	0.0	0.2
56 Administrative and support, waste management and remediation services	25	2.5	4.7
61 Educational services	95	9.5	7.4
62 Health care and social assistance	125	12.5	10.5
71 Arts, entertainment and recreation	10	1.0	2.1
72 Accommodation and food services	60	6.0	6.7
81 Other services (except public administration)	35	3.5	4.1
91 Public administration	95	9.5	5.8

Source: Statistics Canada 2016.

[10] North American Industry Classification System (NAICS) 2012 - 25% sample data.

3.4 General Wages by Occupation

Table 14: General Wages (Northeast Region, Ontario) by Occupation[11]

Category	Low Wage ($/hour)	Median Wage ($/hour)	High Wage ($/hour)
Engineering Managers (NOC 0211-0)	35.00	52.88	81.73
Restaurant and Food Service Managers (NOC 0631-0)	14.00	19.05	36.38
Supervisors, Petroleum, Gas and Chemical Processing and Utilities (NOC 9212-B)	14.19	27.00	49.76
Logging and Forestry Labourers (NOC 8616-D)	14.00	18.00	25.70
Labourers in Metal Fabrication (NOC 9612-D)	14.00	18.00	31.00
Machine Operators, Mineral and Metal Processing (NOC 9411-C)	16.40	25.00	34.00
Financial and Investment Analysts (NOC 1112-A)			
Supervisors, General Office and Administrative Support Clerks (NOC 1211-B)	14.00	25.00	39.73
Storekeepers and Partspersons (NOC 1522-C)	14.00	19.00	30.00
Industrial Instrument Technicians and Mechanics (NOC 2443-B)			
Retail Sales Supervisors (NOC 6211-B)	14.00	15.50	27.88
Transport Truck Drivers (NOC 7511-C)	14.00	20.25	28.00
Forestry Technologists and Technicians (NOC 2223-B)	20.53	22.75	27.00
Cashiers (NOC 6611-D)	14.00	14.00	14.00
Contractors and Supervisors, Heavy Equipment Operator Crews (NOC 7302-B)	19.23	31.00	45.41
Automotive Service Technicians, Truck and Bus Mechanics and Mechanical Repairers (NOC 7321-B)	14.90	24.95	36.00
Managers in Health Care (NOC 0311-0)	26.22	45.74	62.05
Registered Nurses and Psychiatric Nurses (NOC 3012-A)	23.00	37.40	45.00
Social Workers (NOC 4152-A)	23.00	33.00	41.00
Mine Labourers (NOC 8614-D)	17.00	22.00	37.83

Source: Produced by Government of Canada, Report generated on September 25, 2017.
https://www.jobbank.gc.ca/LMI_report_area.do?lang=eng&area=6363&reportOption=wage

[11] For more wage rates please visit:
http://www.jobbank.gc.ca/LMI_report_area.do?lang=eng&area=6363&reportOption=wage

3.5 Largest Employers

Table 15: Largest Private Sector Employers

Name	Sector	No. of Employees (approximate)
Ryam Lumber	Forestry	168
Canadian Pacific Railway	Transportation	105
True North Timber	Forestry	50
Goldcorp	Mining	43 (includes sub-contractors)
Chapleau Valu-Mart	Retail	37

Source: The Township of Chapleau

Table 16: Largest Public Sector Employers

Name	Sector	No. of Employees (approximate)
Chapleau Health Services	Health Care	114
Ministry of Natural Resources and Forestry	Provincial Government	90 (includes contract/summer positions)
Chapleau Elementary and Secondary School	Education	34
Chapleau Child Care Centre	Child Care and Education	30
Township of Chapleau	Municipal Government	25

Source: The Township of Chapleau.

4 Transportation and Shipping

4.1 Highways

Major arterial highways serving the region:

- Highway 129 connects Chapleau to Highway 101 and to Sudbury. Highway 129 also provides access to the Sault Ste. Marie US border crossing.
- Highway 101, provides access to Timmins and the Trans-Canada Highway.

Table 17: Distance to Urban Centres

Distance to Major Urban Centres		
	Km	**Miles**
Alliston	733	455
New York, NY	1,563	971
Buffalo, NY	933	579
Kingston	1,033	641
Kitchener/Waterloo	858	533
London	945	587
Montreal	1,056	656
North Bay	563	349
Ottawa	920	571
St. Catharines	885	549
Sault Ste. Marie	313	194
Thunder Bay	623	387
Toronto	789	490
Windsor	881	547

Source: McSweeney & Associates from Google Maps

Table 18: Distance to Major US Border Crossings

Distance to Border Crossings		
	Km	**Miles**
Massena/Cornwall	1,017	631
Ogdensburg/Prescott	987	613
Alexandria Bay/Ivy Lea	1,043	648
Lewiston/Queenston	905	562
Niagara Falls/Niagara Falls	902	560
Buffalo/Fort Erie	926	575
Detroit/Windsor	1,123	1,407
Port Huron/ Sarnia	1,062	659
Sault Ste. Marie/Sault Ste. Marie	313	194
Grand Portage/Thunder Bay	623	387
International Falls/Fort Frances	946	587
Baudette/Rainy River	1,036	643

Source: McSweeney & Associates from Google Maps

4.2 Rail Services

Canadian Pacific
CP has numerous routing options across Canada and through the U.S. as well as excellent North American reach through gateways with all Class I railways. We have extensive Canadian and U.S. shortline partners and serve leading Atlantic and Pacific port facilities.

Chapleau Office: 50 Dufferin Street Chapleau, ON P0M 1K0 Phone: 705-864-1214 Fax: 705-864-2752	*Canadian Head Office:* 7550 Ogden Dale Rd S.E. Calgary, AB T2C 4X9 Web: www.cpr.ca
Transload Facility: Mansour Group 2502 Elm Street, PO Box 670 Stn B Sudbury, Ontario (ON) P3E 4R6 Phone: 705-671-6642 Fax: 705-682-4283	*Intermodal Facility:* Vaughan Intermodal Terminal 6830 Rutherford Road Kleinburg, ON L0J 1C0 Phone: 1-888-333-8111 Fax: 905-893-5027

VIA Rail
VIA Rail Canada is an independent Crown corporation established in 1978. VIA operates trains in all regions of Canada over a network spanning the country from the Atlantic to the Pacific, and from the Great Lakes to Hudson Bay.

Mailing Address:
Customer Relations
VIA Rail Canada Inc.
PO Box 8116, Suc Centre-Ville
Montréal, QC
H3C 3N3
Phone: 1-800-681-2561
Fax: 514-871-6104
Email: customer_relations@viarail.ca
Web: http://www.viarail.ca/

CN Rail
CN is a leader in the North American rail industry. Following its acquisition of Illinois Central in 1999, WC in 2001 and GLT in 2004, as well as its partnership agreement with BC Rail in 2004, CN provides shippers with more options and greater reach in the rapidly expanding market for north-south trade.

Headquarters:
935 de La Gauchetière Street West
Montreal, QC
H3B 2M9
Phone: 1-888-888-5909
Web: http://www.cn.ca/en/index.htm

Intermodal Terminals:
Airport Road & Intermodal Drive
76 Intermodal Drive
Brampton, ON
L6T 5K1
Web: www.cn.ca/en/shipping-how-intermodal-terminals.htm

4.3 Airports

Chapleau Airport **(YLD)**
Hwy 101 East
Chapleau, ON
P0M 1K0
Phone: 705-864-1828
Web: http://www.chapleau.ca/en/townhall/airport.asp

Timmins Victor M. Power Airport
(Formerly Timmins Airport)
4599 Airport Road
Timmins, ON
P4N 7C3
Phone: 705-360-2636
Web: http://timminsairport.com/

Sault Ste. Marie Airport
1 - 475 Airport Road
Sault Ste. Marie, ON
P6A 5K6
Phone: 705-779-3031
Web: www.saultairport.com/

Greater Sudbury Airport
5000 Air Terminal Drive, Suite T202
Garson, ON
P3L 1V4
Phone: 705-693-2514
Web: www.flysudbury.ca/

Toronto Pearson International Airport
6301 Silver Dart Drive
Mississauga, ON
L5P 1B2
Phone: 416-247-7678
Web: www.torontopearson.com/

Ottawa International Airport (International Airport)
Ottawa International Airport Authority
1000 Airport Parkway Private, Suite 2500
Ottawa, ON
K1V 9B4
Phone: 613-248-2125 or 613-248-2000 (Airport Authority Office)
Web: www.yow.ca/

4.4 Ports

Port of Sault Ste. Marie
Essar Steel Algoma Inc.
105 West Street
Sault Ste. Marie, ON
P6A 7B4
Phone: 705-945-2351
Fax: 705-945-2203

Contact: Ron Spina
Strategic Sourcing Manager – Raw Materials & Inbound Logistics
Phone: 705-945-2551
Email: ron.Spina@essar.com

Michipicoten Harbour
Wawa, ON
P0S 1K0
Bruce Staines
Phone: 705-856-2988
Email: bstaines@yahoo.ca

Port of Thunder Bay
Thunder Bay Port Authority
100 Main Street
Thunder Bay, ON
P7B 6R9
Phone: 807-345-6400
Fax: 807-345-9058
Web: http://www.portofthunderbay.com/

The Port of Thunder Bay is located at the head of the Great Lakes/St. Lawrence Seaway System, a dynamic navigable waterway that stretches 3700 kilometres into the heart of the North American continent.

A one-way voyage through the Seaway to Thunder Bay takes about five days with ships 228.6 metres in length, 23.8 metres in width with a draft of 8.2 metres being elevated some 180 metres through 16 of the most efficient locks in the world.

Port of Montreal (Ocean Port)
Port of Montreal Building
2100, Pierre-Dupuy Avenue, Wing 1
Montreal, QC
H3C 3R5
Phone: 514-283-7011
Fax: 514-283-0829
Web: http://www.port-montreal.com/en/index.html

The Port of Montreal is one of the safest international ports in the world. It is 1,000 km from Chapleau.

Ports Toronto (Ocean Port)
60 Harbour Street
Toronto, ON
M5J 1B7
Phone: 416-863-2000
Fax: 416-863-4830
Web: http://www.portstoronto.com/

The Port of Toronto provides immediate access to marine routes, major highways and rail facilities, serving as a transportation hub for a much wider market, including all of Ontario, Northwestern Quebec, Midwest Canada and Northeastern U.S.A. It is 790 km away from Chapleau.

5 Taxes and Utilities

5.1 Local Property Tax Rates

Table 19: Local Property Tax Rates, 2018

Property Class	Total Tax Rates
Residential	0.03079673
Multi-Residential	0.04623900
Commercial Occupied	0.05245161
Commercial Excess Land	0.03671614
Commercial Vacant Land	0.03671614
Industrial Occupied	0.08178505
Industrial Excess Land	0.05316028
Industrial Vacant Land	0.05316028
Farm Occupied	0.00769918

Source: Township of Chapleau

Table 20: Provincial Land Tax Rates, 2015

Property Class	Tax Rate Inside School Boards	Tax Rates Outside School Boards
Residential	0.001717	0.000354
Multi-Residential	0.001717	0.000354
Farm	0.000429	0.000088
Managed Forest	0.000429	0.000088
Commercial	0.000694	0.000694
Industrial	0.000542	0.000542
Pipeline	0.002453	0.002453

Source: Ontario Ministry of Finance

Table 21: Provincial Land Tax Rate: Railway Companies and Power Utilities

Property Ownership	Type of Land/Land Use	Rate Per Acre
Railway Company	Roadway or right-of-way	$0.12
Prescribed Power Utility	Land as a transmission or distribution corridor	$2.65

Source: Ontario Ministry of Finance

For more information on Provincial Land Tax go to http://www.fin.gov.on.ca/en/tax/plt/ or contact the Provincial Land Tax Office in Thunder Bay at plt@thunderbay.ca or by phone at 1-866-400-2122.

5.2 Federal and Provincial Income Tax Rates

Table 22: 2018 Corporate Taxes – Non-Canadian Controlled

	Manufacturing & Processing Income	Active Business Income	Investment Income
Federal rates			
General corporate rate	38.0%	38.0%	38.0%
Federal abatement	(10.0)	(10.0)	(10.0)
	28.0	28.0	28.0
M&P deduction	(13.0)	0.0	0.0
Rate deduction	0.0	(13.0)	(13.0)
Net federal Rate	15.0	15.0	15.0
Provincial/Territorial Rates			
Ontario	**10.0**	**11.5**	**11.5**

Source: https://home.kpmg.com/content/dam/kpmg/ca/pdf/2018/04/substantively-enacted-tax-rates-for-general-corporations-for-2018-and-beyond.pdf

Table 23: 2018 Corporate Taxes – Canadian Controlled

	Small Business Income up to $500,000	Active Business Income	Investment Income
Federal rates			
General corporate rate	38.0%	38.0%	38.0%
Federal abatement	(10.0)	(10.0)	(10.0)
	28.0	**28.0**	**28.0**
Small business deduction	(18.0)	0.0	0.0
Rate reduction	0.0	(13.0)	0.0
Refundable Tax	0.0	0.0	10.7
Net federal Rate	**10.0**	**15.0**	**38.7**
Provincial/Territorial Rates			
Ontario	**3.5**	**11.5**	**11.5**

Source: https://home.kpmg.com/content/dam/kpmg/ca/pdf/2018/04/federal-and-provincial-territorial-tax-rates-for-income-earned-by-a-ccpc—2018.pdf

Table 24: Ontario's Capital Tax Elimination Plan

Date	Deduction ($M)	*M&P and Resources	Regular Corporations	First $400M of Taxable Capital	Taxable Capital above $400M	
					Non-Deposit Taking	Deposit Taking
4-Jan-09	15	Eliminated	0.225	0.45	0.54	0.675
5-Jan-10	15		0.15	0.3	0.36	0.45
1-Jul-10	Eliminated					

Source: http://www.fin.gov.on.ca/en/tax/capital/

Table 25: Personal Income Tax, 2018[12]

Taxable Income ($CDN)	2018 Marginal Tax Rates			
			Canadian Dividends	
	Marginal Rate	Capital Gains	Eligible Dividends	Small Business Dividends
first $40,120	20.05%	10.03%	-6.86%	5.35%
over $40,120 up to $43,953	24.15%	12.08%	-1.20%	10.19%
over $43,953 up to $70,651	31.15%	15.58%	8.46%	18.45%
over $70,651 up to $80,242	32.98%	16.49%	10.99%	20.61%
over $80,242 up to $83,237	35.39%	17.70%	14.31%	23.45%
over $83,237 up to $87,907	39.41%	19.70%	19.86%	28.19%
over $87,907 up to $136,270	43.41%	21.70%	25.36%	32.91%
over $136,270 up to $150,000	46.41%	23.20%	29.52%	36.45%
over $150,000 up to $220,000	47.97%	23.98%	31.67%	38.29%
over $220,000	49.53%	24.76%	33.82%	40.13%

Source: http://www.taxtips.ca/taxrates/on.htm

Table 26: Sales Tax

Sales Tax	Before July 1, 2010	2014
GST (goods and services tax)	5%	
PST (provincial sale tax or retail sales tax)	8%	
HST (harmonized sales tax)		13%

Source: http://www.cra-arc.gc.ca/tx/bsnss/tpcs/gst-tps/rts-eng.html

[12] Combined Federal & Provincial Tax Brackets and Tax Rates Including Surtaxes

5.3 Waste Management

The Township of Chapleau operates and maintains the municipal landfill site. The landfill site is located on Highway 129.

Hours of Operation:
Tuesdays - Fridays: 10:00 a.m. to 2:00 p.m.
Saturdays: 10:00 a.m. to 4:00 p.m.
Sundays, Mondays and Holidays: Closed

Table 27: Landfill and Tipping Fees (2018)

Category	Tokens[13] Required
Up to three (3) Garbage Bags, under 40 lbs	2 (Blue)
Per car trunk / Small utility trailer or Partial ¼ or ½ ton truck box	5 (Blue)
Per ¼ ton truck box (1.6 yd ³ capacity)	6 (Blue)
Per ½ ton truck box (2.4 yd ³ capacity)	7 (Blue)
Per ¾ ton truck box (3.0 yd ³ capacity)	12 (Blue)
Per 1 ton truck box or Tandem axle trailer (3.5 yd ³ capacity)	14 (Blue)
Per 3 ton truck box (5.0 yd ³ capacity)	20 (Blue)
Per 5 ton truck box - one axle (8.0 yd ³ capacity)	32 (Blue)
Per Tandem - two axles (12.0 yd ³ capacity)	48 (Blue) Non-Res. 96
Per Tandem - two axles (15.0 yd ³ capacity)	60 (Blue) Non-Res. 120
Per Tandem - two axles (20.0 yd ³ capacity)	80 (Blue) Non-Res 160
Per Tri-Axle – three axles (25.0 yd ³ capacity)	100 (Blue) Non-Res 200
Per each additional cubic yard over 25.0 yd ³	10 (Blue) Non-Res. 20
Compacted Refuse (e.g. refuse collection truck) per yard	12 (Blue) Non-Res 24
Passenger tire (rim off) (up to 20" rim size)	5 (Red)
Commercial truck tire (rim off) (up to 24" rim size)	15 (Red)
Derelict vehicles (Free of all fluids, tires, and batteries)	101 (Blue)
All tokens will be in denominations of $1.00, $5.00, $25.00 and $50.00 (1 token = $ 1.00, HST not required). Acceptance of any waste material is at the complete discretion of the Corporation of the Township of Chapleau. The Corporation reserves the right to refuse the disposal of any waste material. Those individuals wishing to deposit large quantities of waste, must receive written approval from the Corporation. For further information regarding this user fee system, or the landfill site in general, please feel free to contact the Public Works Superintendent at 705-864-1334.	

Source: Township of Chapleau, http://www.chapleau.ca/en/townshipservices/landfill.asp

[13] Tokens may only be purchased at the Chapleau Civic Center (Mon - Fri 8:30 a.m. to 4:30 p.m.)

5.4 Communications Infrastructure

Table 28: Communications Infrastructure

Service	Company Name
Local Internet Provider	Vianet, Bell, Ontera
Satellite TV	Bell, Shaw

Source: Township of Chapleau

5.5 Electricity

Service Provider: Chapleau Public Utilities Corporation
Phone: 705-864-0111
Web: http://www.chapleau.ca/en/townshipservices/publicutilities.asp

Table 29: Chapleau Public Utilities Corporation Electricity Rates

Monthly Rates and Charges rates	Effective May 1, 2018
General Service Less Than 50 kW	
Service Charge	$35.18
Rate Rider Smart Meter entity Charge – effective until October 31, 2018	$0.57
Distribution Volumetric Rate	$0.0179/kWh
Low Voltage Service Rate	$0.0006/kWh
Retail Transmission Rate - Network Service Rate	$0.0060/kWh
Retail Transmission Rate - Line & Transformation Connection Service Rate	$0.0016/kWh
Wholesale Market Service Rate	$0.0032/kWh
Wholesale Market Service Rate - CBR	0.0004/kWh
Rural Rate Protection Charge	$0.0003/kWh
Standard Supply - Administrative Charge (if applicable)	$0.25
Debt retirement – effective April 1, 2018	removed
General Service 50 to 4,999 kW	
Service Charge (Distribution Fixed)	$193.66
Distribution Volumetric Rate	$3.6185/kW
Low Voltage service Rate	$0.2256/kW
Retail Transmission Rate – Network Service Rate (TRN)	$2.5062/kW
Retail Transmission Rate – Line & Transformation Connection Service Rate (TRC)	$0.5763/kW
Wholesale Market Service Rate (IMO)	$0.0032/kWh
Wholesale Market Service Rate (CBR)	$0.0004/kWh
Rural Rate Protection Charge (RRA)	$0.0003/kWh
Standard Supply – Administrative Charge (if applicable)	$0.25

Source: Chapleau Public Utilities Corporation (CPUC): http://www.chapleau.ca/en/townshipservices/ratesdocuments.asp

Table 30: Water Fees

Waterworks Monthly Rate Structure [Effective January 1, 2018]	
Water Rate	
Quarterly Water Billings	$240.24
Sanitary Sewer Rate	
Quarterly Wastewater Billing	$113.63

Source: Township of Chapleau

Table 31: Plumbing Inspection Fees

Plumbing Inspection Fees	
For each plumbing fixture	$5 base fee
For each soil stack	$3
For each interceptor	$3
4 inch building drains, storm drains, sewer or storm sewer	$3
5 inch building drains, storm drains, sewer or storm sewer	$3 per 25 lineal metres
6 inch building drains, storm drains, sewer or storm sewer	$4 per 25 lineal metres
8 inch building drains, storm drains, sewer or storm sewer	$5 per 25 lineal metres
For each additional inspection	$8 per 25 lineal metres
For each plumbing fixture	$15

Source: Township of Chapleau

6 Building and Development Related Fees

6.1 Development Related Fees

Table 32: Permit Fees

Permit Fees	Construction Value
$30 base fee	≤ $1,000
Add $8 per $1,000 Construction Value	≤ $100,000
Add $4 per $1,000 Construction Value	> $100,000

Source: Township of Chapleau

Table 33: Application Fees

Planning Fees	
Zoning By-Law Amendment (minor)	$400
Zoning By-Law Amendment (major)	$600
Official Plan Amendment (OPA)	$600
Minor Variance	$300
Zoning Searches	$50
Consent Application	$300

Source: Township of Chapleau

Table 34: Infrastructure Installation Fees

Building Fees	
Water and Sewer Line Connections	$800 (each)
Water On/Off	$40
Water Thawing (reg. work hrs, 2 hr. limit)	$150 (1st)
"	$200 (2nd)
"	$300 (3rd)

Source: Township of Chapleau

For further information, please contact:

Township of Chapleau
20 Pine Street W, PO Box 129
Chapleau, ON
P0M 1K0
Phone: 705-864-1330
Web: www.chapleau.ca

7 Business Support Programs and Services

7.1 Government

Township of Chapleau
20 Pine Street West
PO Box 129
Chapleau, ON P0M 1K0
Phone: 705-864-1330
Fax: 705-864-1824
Web: http://www.chapleau.ca

Service Ontario
Main Floor, 190 Cherry Street
Chapleau, ON P0M 1K0
General Inquiry: 1-800-267-8097
Health Card Inquiry: 1-888-376-5197
Driver & Vehicle Inquiry: 1-800-387-3445
Web: www.services.gov.on.ca

The Manitoulin-Sudbury District Services Board (DSB)
Integrated Social Services
Box 1299, 12 Birch Street East
Chapleau, ON P0M 1K0
Phone: 705-864-0430
Toll free: 1-877-245-5595
Toll free Fax: 1-866-397-3334
Web: http://www.msdsb.net/

Carol Hughes, MP
255 Hwy 108 N (Main Office)
Elliot Lake, ON P5A 2L9
Phone: 705-848-8080
Toll free 1-855-297-4200
Fax: 705-848-1818
Email: carol.hughes@parl.gc.ca
Web: http://carolhughes.ndp.ca/

Michael Mantha, MPP
Unit 310, Lester B Pearson Civic Ctr.
255 Highway 108th North
Elliot Lake, ON P5A 2T1
Phone: 705-461-9710
Toll Free: 1-800-831-1899
Fax: 705-461-9720
Email: mmantha-co@ndp.on.ca
Web: http://www.michaelmantha.com/

Ministry of Northern Development and Mines
Joel Lafrance
Northern Development Officer – Sault Ste. Marie and Area
191 Cherry Street
Chapleau, ON P0M 1K0
Phone: 705-864-4167
Email: joel.lafrance@ontario.ca

FedNor / Industry Canada
Lisa McHugh
Community Economic Development Officer
2 Queen Street East
Sault Ste. Marie, ON P6A 1Y3
Phone: 705-941-2027
Fax: 705-941-2085
Email: lisa.mchugh@ic.gc.ca

7.2 Non-Governmental Organizations

APANO: Aboriginal Peoples Alliance of Northern Ontario
8 Lorne Street
P.O. Box 1210
Chapleau, ON P0M 1K0
Phone: 705-864-0556
Fax: 705-864-0882

7.3 Education, Employment and Training

7.3.1 Post-Secondary Institutions in Northern Ontario

Algoma University
1520 Queen Street East
Sault Ste. Marie, ON
P6A 2G4
Phone: 705-949-2301
Web: www.algomau.ca

Laurentian University
935 Ramsey Lake Road
Sudbury, ON
P3E 2C6
Phone: 705-675-1151
Web: www.laurentian.ca

Nipissing University
100 College Drive
North Bay, ON
P1B 8L7
Phone: 705-474-3450
Web: www.nipissingu.ca

Université de Heart a Timmins
395 Theriault Blvd.
Timmins, ON
P4N 3K6
Phone: 705-267-2144
Web: www.uhearst.ca

Northern College
4715 Highway 101 East
South Porcupine, ON
P0N 1H0
Phone: 705-235-3211
Web: www.northernc.on.ca/timmins-campus

Lakehead University
955 Oliver Road
Thunder Bay, ON
P7B 5E1
Phone: 807-343-8110
Web: www.lakeheadu.ca

Anishinabek Educational Institute
1 Migizii Miikan Rd, PO Box 711
North Bay, ON
P1B 8J8
Phone: 705-497-9127
Web: www.aeipostsecondary.ca

Collège André-Grasset - A Fugereville
Fugèreville, QC
Phone: 514-381-4293
Web: www.grasset.qc.ca

Northern College - Haileybury Campus
640 Latchford Street, Box 2060
Haileybury ON
P0J 1K0
Phone: 705-672-3376
Web: www.northernc.on.ca/haileybury-campus

Laurentian University - University De Hearst
Mailbag 580
60 9th Street
Hearst, ON
P0L 1N0
Phone: 705-372-1781
Web: www.uhearst.ca

7.3.2 Adult and Distance Education

Contact North 4 Maple Street, PO Box 309 Chapleau, ON P0M 1K0 Phone: 705-864-1410 Fax: 705-864-1404 Email: chapleau@contactnorth.ca	***Independent Learning*** Chapleau Learning Centre 34 Birch Street, PO Box 1109 Chapleau, ON P0M 1K0 Phone: 705-864-2323 Fax: 705-864-1955 Email:clearn@adsb.on.ca Web: http://www.chapleaulearningcentre.com

FormationPLUS
69 Birch Street, PO Box 714
Chapleau, ON
P0M 1K0
Phone: 705-864-2763
Fax: 705-864-2822
Email: formationplus@vianet.ca
Web: http://quatrain.org/fr/fplus/

FormationPLUS is a non-profit organization with a mandate to serve the francophone residents of Chapleau and surrounding areas in communications, mathematics, science, computing, general interest courses and employability.

7.4 Financial

RBC Royal Bank 33 Birch Street Chapleau, ON P0M 1K0 Phone: 705-864-0570 Web: www.RBC.com	***Northern Credit Union*** 34 Birch Street Chapleau, ON P0M 1K0 Phone: 705-864-1841 Web: www.northerncu.com

7.5 Real Estate

Chapleau Real Estate Limited 106 Birch Street PO Box 158 Chapleau, ON P0M 1K0 Phone: 705-864-1115 Fax: 705-864-1100 Email: lisa@chapleaurealestate.com Web: http://www.chapleaurealestate.com	***R.T. McKee Realty Ltd – Brokerage*** Rita T. McKee-Gavan, Broker of Record 24 Aberdeen Street South PO Box 214 Chapleau, ON P0M 1K0 Tel: 705-864-1775 Fax: 705-864-1776 Email: rita@rtmckeerealty.com Web: www.rtmckeerealty.com

For a complete listing of industrial and business properties, please contact:

Township of Chapleau
20 Pine Street W, PO Box 129
Chapleau, ON P0M1K0
Phone: 705-864-1330
Web: www.chapleau.ca

8 Quality of Life

During the summer, make Chapleau the starting point for your adventure, and explore early 24,000 square km of canoe country, go fishing on one of the many surrounding lakes or spend a night under the stars at one of four nearby provincial parks. Discover a new trail on your ATV, or hike down a Crown game preserve nature trail and try to spot wildlife at one of many viewing stations. The Chapleau area is also home to approximately 25 remote tourism operations and lodges which provide hunting, fishing, and eco-tourism opportunities.

In winter, enjoy a game of hockey, or try figure skating or curling at the Chapleau recreation and Community Complex. Winter weather also provides endless opportunities for outdoor activities such as ice fishing, snowshoeing, and cross-country skiing on - approximately 12 km of trails, or snowmobiling on hundreds of km of groomed trails. Hit the slopes at the Chapleau Ski Club, which offers a vertical drop of 130 feet, and a run of over 1000 feet.

For those who prefer to stay indoors, the Chapleau recreation and Community Complex hosts community events throughout the year, and the francophone Cultural Centre and first nations communities offer distinct cultural experiences.

8.1 Housing Characteristics

Table 35: Residential Assessment Property Values, MPAC 2016

Property Type	Median Assessment
Single family detached (not on water)	$77,00
Semi-detached residential	$42,000
Single family detached on water	$107,500

Source: MPAC 2016.

Table 36: Dwelling Characteristics, 2016

Characteristics	Chapleau	Ontario
Total number of occupied private dwellings	870	5,169,175
Average number of rooms per dwelling	6.1	6.3
Owned	620	3,601,825
Rented	250	1,559,720
Average value of dwelling $	119,358	506,409

Source: Statistics Canada 2016.

8.2 Health, Social and Community Services

8.2.1 Health and Social Services

Chapleau Child Care Centre de Garde D'Enfants
28 Golf Course Road
Chapleau, ON
P0M 1K0
Phone: 705-864-1886
Web: www.chapleauchildcare.ca

Child, Youth and Family Services Centre
34 Birch Street East
Chapleau, ON
P0M 1K0
Phone: 705-864-0860
Web: www.cfcnorth.ca

Service Canada
Chapleau Scheduled Outreach Site
12 Birch Street
Chapleau, ON
P0M 1K0
Phone: 1-800-622-6232
Web: www.servicecanada.gc.ca
Open: 3rd Tuesday of every Month, 8:30am-2:30pm

8.2.2 Regional Health Services

Chapleau General Hospital
Services de santé de Chapleau Health Services
6 Broomhead Road
Chapleau, ON
P0M 1K0
Phone: 705-864-1520
Email: communications@sschs.ca
Web: www.sschs.ca

Chapleau Medical Centre
2 Broomhead Road
Chapleau, ON
P0M 1K0
Phone: 705-864-0210

Turning Point
(Mental Health Service)
6 Broomhead Road
Chapleau, ON
P0M 1K0
Phone: 705-864-1520
Web: www.sschs.ca

Sudbury & District Health Unit
101 Pine Street
Chapleau, ON
P0M 1K0
Phone: 705-864-1610
Web: www.sdhu.com

Cedar Grove
(Supported Independent Living)
6 Broomhead Road
Chapleau, ON
P0M 1K0
Phone: 705-864-1520
Web: www.sschs.ca

Bignucolo Residence
(Long-term Care Facility)
6 Broomhead Road
Chapleau, ON
P0M 1K0
Phone: 705-864-1520
Web: www.sschs.ca

Telehealth Ontario
Phone: 1-866-797-0000
Free Access to a Registered Nurse

8.3 Education

Table 37: Chapleau Schools

Elementary Schools			
School Name	**Location**	**Phone**	**Web**
Chapleau Public School	20 Teak Street	705-864-1170	www.adsb.on.ca
École élémentaire catholique Sacré-coeur	14 Strathcona Street	705-864-0281	www.nouvelon.ca
Our Lady of Fatima Catholic School	14 Strathcona Street	705-864-1081	www.hscdsb.on.ca
Secondary Schools			
School Name	**Location**	**Phone**	**Web**
Chapleau High School	20 Teak Street	705-864-1452	www.adsb.on.ca
École secondaire catholique Trillium	9 Broomhead Road	705-864-1211	www.nouvelon.ca

Source: The Township of Chapleau

8.4 Emergency and Protective Services

Emergency Phone Number Phone: 911	***Crisis Intervention*** Phone: 705-675-4760	***Ontario Provincial Police*** Phone: 1-888-310-1122
Poison Information Phone: 1-800-268-9017, 1-877-750-2233 (TTY Only)	***Drug & Alcohol Treatment Info Line*** Phone: 1-800-565-8603	***Communications Centre*** Phone: 1-888-310-1133 (TTY only)
Crime Stoppers Phone: 1-800-222-8477	***Kids Help Phone*** Phone: 1-800-668-6868	***Wife Assault Helpline*** Phone: 1-800-461-2242
Environmental Spill Reporting Phone: 1-800-268-6060	***Ontario Problem Gambling Helpline*** Phone: 1-888-230-3505	***Air-Sea Search and Rescue*** Phone: 1-800-267-7270
Assaulted Women's Helpline Phone: 1-866-863-0511, 1-866-863-7868 (TTY Only)	***Telehealth Ontario*** Phone: 1-866-797-0000, 1-866-797-0007 (TTY only)	***Forest Fire and Flood Reporting*** Phone: 1-888-863-3473

8.5 Recreation and Tourism

For more on where to stay and what to do in Chapleau, please visit the Township of Chapleau's website: www.chapleau.ca

8.6 Events

Table 38: Annual Events

Annual Events	
Name of Event	**Date**
Relay for Life	TBD
Brunswick House First Nation Pow Wow	TBD
Chapleau Cree First Nation Pow Wow	TBD
Chapleau Arts and Crafts Fall Fair	TBD
Chapleau General Hospital Annual Golf Classic	TBD
Centre Culturel Louis-Hémon de Chapleau Hunters' Ball	TBD
Community Christmas Tree Lighting	TBD
Winter Carnival	TBD
Chapleau Arts and Crafts Fall Fair	TBD
National Aboriginal Day Celebrations	June 21st
Canada Day Celebrations and Fireworks	July 1st
Franco-Ontarian Day	September 25th
Remembrance Day Ceremonies	November 11th
CP Rail Holiday Train	November/December
Rotary Club of Chapleau Ice Fishing Derby	February
Wildwood Bible Camp	June-August

Source: The Township of Chapleau

8.7 Local Media

Table 39: Newspapers

Newspaper	Contact
Chapleau Express	14 Richard Chapleau, ON P0M 1K0 Phone: 705-864-2579 Web: www.chapleauexpress.ca
Northern Ontario Business	158 Elgin Street Sudbury, ON P3E 3N5 Phone: 705-673-5705

Source: The Township of Chapleau

Table 40: Radio Stations

Radio Station	Affiliation
CJWA-1 at FM 100.7	JJAM FM
CHAP at FM 95.9	CHYC-FM Sudbury
CFJW at FM 93.7	Township Emergency Alert System
CBON-28 at FM 91.9	Radio-Canada
CBCU at FM 89.9	CBC Radio One
CHYC-FM 98.9	Le Loup

Source: The Township of Chapleau

Table 41: Cable Service and Television

Name	Phone
Vianet	705-860-9996 x3000
Bell TV	1-888-310-2355
Shaw	1-888-554-7827
TV Station	**Affiliation**
CTV Northern Ontario	CTV News

Source: The Township of Chapleau

Appendix - Incentives

Capital Funding Programs

NextGen Biofuels Fund - Sustainable Development Technology Canada
http://www.sdtc.ca/index.php?page=nextgen-funding-niche&hl=en_CA

SD Tech Fund - Sustainable Development Technology Canada
http://www.sdtc.ca/index.php?page=sdtech-funding-niche&hl=en_CA

Business Development Bank of Canada
http://www.bdc.ca/en/home.htm

Community Futures Program - Ontario
http://www.icce.ca/eic/site/fednor-fednor.nsf/eng/h_fn01468.html

SMART Program - Canadian Manufacturers & Exporters
http://www.cme-smart.ca/

NOHFC - Northern Energy Program
http://www.mndm.gov.on.ca/nohfc/programs/northern_energy_e.asp

Strategic Aerospace and Defence Initiative - Industry Canada
http://ito.ic.gc.ca/eic/site/ito-oti.nsf/eng/h_00022.html

FuturPreneur Canada (Formerly CYBF)
https://www.futurpreneur.ca/en/

NOHFC - Emerging Technology Program
http://www.mndm.gov.on.ca/nohfc/programs/emerging_technology_e.asp

Eastern Ontario Development Fund - Ministry of Economic Development
http://www.omafra.gov.on.ca/english/food/industry/east-ont-dev-fund.htm

Ontario Innovation Demonstration Fund
https://www.mentorworks.ca/what-we-offer/government-funding/capital-investment/idf/

Rural Economic Development (RED) Program
https://www.ontario.ca/page/rural-economic-development-program

Ontario Emerging Technologies Fund - Ontario Capital Growth Corporation
http://www.ocgc.gov.on.ca/site/en/funds/ontario-emerging-technologies-fund/

Canada Small Business Financing Program - Industry Canada
http://www.ic.gc.ca/eic/site/csbfp-pfpec.nsf/eng/Home

Commercialization Funding Programs

Ontario Centres of Excellence Inc.
http://www.oce-ontario.org/programs

NextGen Biofuels Fund - Sustainable Development Technology Canada
http://www.sdtc.ca/index.php?page=nextgen-funding-niche&hl=en_CA

SD Tech Fund - Sustainable Development Technology Canada
http://www.sdtc.ca/index.php?page=sdtech-funding-process&hl=en_CA

NOHFC - Emerging Technology Program
http://www.mndm.gov.on.ca/nohfc/programs/emerging_technology_e.asp

Ontario Research Fund - Ontario Ministry of Research and Innovation
http://www.mri.gov.on.ca/english/programs/ResearchFund.asp

Conservation Fund
http://www.ieso.ca/get-involved/funding-programs/conservation-fund/cf-overview

Eastern Ontario Development Fund - Ministry of Economic Development
http://www.omafra.gov.on.ca/english/food/industry/east-ont-dev-fund.htm

Health Technology and Commercialization Program (HTCP)
http://www.oce-ontario.org/programs/commercialization-programs/health-technologies-fund/how-it-works

Industrial assistance Research Program (IRAP)
https://www.nrc-cnrc.gc.ca/eng/irap/

MaRS Discovery District (MaRS)
www.marsdd.com

Digital Media Funding Programs

Digital Technology Adoption Pilot Program (DTAPP)
https://www.nrc-cnrc.gc.ca/eng/irap/dtapp/resources/index.html

NOHFC - Emerging Technology Program
http://www.mndm.gov.on.ca/nohfc/programs/emerging_technology_e.asp

Ontario Film and Television Tax Credit (OFTTC)
http://www.omdc.on.ca/film_and_tv/tax_credits/OFTTC.htm

Ontario Interactive Digital Media Tax Credit
http://www.omdc.on.ca/interactive/Tax_Credits.htm

Ontario Production Services Tax Credit (OPSTC)
http://www.omdc.on.ca/film_and_tv/tax_credits/OPSTC.htm

Ontario Sound Recording Tax Credit (OSRTC)
http://www.omdc.on.ca/music/Tax_Credits/OSRTC.htm

Ontario Computer Animation and Special Effects Tax Credit (OCASE)
http://www.omdc.on.ca/film_and_tv/tax_credits/OCASE.htm

Ontario Book Publishing Tax Credit (OBPTC)
http://www.omdc.on.ca/book/tax_credits/OBPTC.htm

Film or Video Production Services Tax Credit Program - Canada Revenue Agency
https://www.canada.ca/en/revenue-agency/services/tax/international-non-residents/film-media-tax-credits/film-video-production-services-tax-credit-program.html

Energy Funding Programs

NextGen Biofuels Fund - Sustainable Development Technology Canada
http://www.sdtc.ca/index.php?page=nextgen-funding-niche&hl=en_CA

SMART Program - Canadian Manufacturers & Exporters
http://www.cme-smart.ca/

NOHFC - Northern Energy Program
http://www.mndm.gov.on.ca/nohfc/programs/northern_energy_e.asp

Save on Energy High Performance New Construction
www.saveonenergy.ca

Feed-in Tariff Program – Independent Electricity System Operator (IESO)
http://www.ieso.ca/sector-participants/feed-in-tariff-program/overview

Conservation Fund
http://www.ieso.ca/get-involved/funding-programs/conservation-fund/cf-overview

Export Funding Programs

Canadian Commercial Corporation (CCC)
http://www.ccc.ca

Export Market Access - A Global Expansion Program
http://exportaccess.ca/en/home

Export Development Canada
http://www.edc.ca/

New Exporters to Border States (NEBS)
https://www.ontario.ca/tradecalendar/nebs-new-exporters-border-states-program

Market Xpansion Loan
http://www.bdc.ca/en/solutions/financing/Pages/fs_market_expansion.aspx

Going Global Innovation - Foreign Affairs and International Trade Canada
http://tradecommissioner.gc.ca/funding-financement/ggi-vmi/index.aspx?lang=eng

Export Guarantee Program
http://www.edc.ca/EN/our-solutions/financing/Pages/export-guarantee-program.aspx

Investment Accelerator Fund
http://www.marsdd.com/aboutmars/partners/iaf/

SMART Prosperity Now Program
http://www.cme-smart.ca/

Human Resources and Training Funding Programs

Employer Signing Bonus
http://www.tcu.gov.on.ca/eng/employers/emp_bonus.html

Ontario Centres of Excellence Inc.
http://www.oce-ontario.org/programs

Apprenticeship Job Creation Tax Credit - Canada Revenue Agency
http://www.cra-arc.gc.ca/tx/ndvdls/tpcs/ncm-tx/rtrn/cmpltng/ddctns/lns409-485/412/jctc-eng.html

NOHFC - Northern Ontario Youth Internship and Co-op Program
http://www.mndm.gov.on.ca/nohfc/programs/youth_internship_and_co-op_e.asp

Connect Canada Internship Program
http://connectcanadainternships.ca/

Canada Summer Jobs
https://www.canada.ca/en/employment-social-development/services/funding/canada-summer-jobs/apply.html

Youth Employment Program - National Research Council Canada
https://www.nrc-cnrc.gc.ca/eng/irap/services/youth_initiatives.html

Canadian Institutes of Health Research - Innovation and Industry Programs
http://www.cihr-irsc.gc.ca/e/37788.html

Ontario Labour Market Partnerships
http://www.tcu.gov.on.ca/eng/employers/labourMarket.html

Work-Sharing Program - Human Resources and Skills Development Canada
https://www.canada.ca/en/employment-social-development/services/work-sharing/application.html

Scientists and Engineers in Business Initiative
http://www.innovationcluster.ca/2010/10/new-feddev-initiative-for-scientists-and-engineers-in-business-announced/

Industrial Research Assistance Program - National Research Council Canada
https://www.nrc-cnrc.gc.ca/eng/irap/l

Apprenticeship Training Tax Credit
http://www.rev.gov.on.ca/en/credit/attc/

Cooperative Education Tax Credit (CETC)
http://www.fin.gov.on.ca/en/credit/cetc/

NOHFC - Enterprise North Job Creation Program
http://www.mndm.gov.on.ca/nohfc/programs/enterprises_north_job_creation_e.asp

Ontario Targeted Wage Subsidy
https://www.canada.ca/en/services/business/hire/wagesubsidiesotherassistanceprograms.html

Rural Economic Development (RED) Program
https://www.ontario.ca/page/rural-economic-development-program

Summer Company
https://www.ontario.ca/page/summer-company-program-guidelines

FEDNOR-Youth Internships - Private Sector Program
http://fednor.gc.ca/eic/site/fednor-fednor.nsf/eng/fn03445.html

MaRS Discovery District (MaRS)
www.marsdd.com

Research and Development Funding Programs

Ontario Centres of Excellence Inc.
http://www.oce-ontario.org/

NextGen Biofuels Fund - Sustainable Development Technology Canada
http://www.sdtc.ca/index.php?page=nextgen-funding-niche&hl=en_CA

SD Tech Fund - Sustainable Development Technology Canada
http://www.sdtc.ca/index.php?page=sdtech-funding-process&hl=en_CA

Ontario Business Research Institute Tax Credit (OBRITC)
http://www.fin.gov.on.ca/en/bulletins/ct/obitc_frost_0002.html

Mitacs Accelerate
http://www.mitacs.ca/accelerate

Industrial R & D Fellowships - Natural Sciences and Engineering Research Council of Canada
http://www.nserc-crsng.gc.ca/Students-Etudiants/PD-NP/Industrial-Industrielle_eng.asp

Youth Employment Program - National Research Council Canada
http://www.hrsdc.gc.ca/eng/home.shtml

Strategic Aerospace and Defence Initiative - Industry Canada
http://ito.ic.gc.ca/eic/site/ito-oti.nsf/eng/h_00022.html

Communications Research Centre Canada - Industry Canada
http://www.crc.gc.ca/eic/site/069.nsf/eng/h_00022.html

Canadian Institutes of Health Research - Innovation and Industry Programs
http://www.cihr-irsc.gc.ca/e/37788.html

NOHFC - Emerging Technology Program
http://www.mndm.gov.on.ca/nohfc/programs/emerging_technology_e.asp

Going Global Innovation - Foreign Affairs and International Trade Canada
http://tradecommissioner.gc.ca/funding-financement/ggi-vmi/index.aspx?lang=eng

Ontario Innovation Tax Credit (OITC)
http://www.rev.gov.on.ca/english/credit/oitc/index.html

FEDNOR - Applied Research and Development Program
http://fednor.gc.ca/eic/site/fednor-fednor.nsf/eng/fn03444.html

Ontario Research Fund - Ontario Ministry of Research and Innovation
https://www.ontario.ca/page/research-funding

Appendix J Facebook Comments

1. Although an increase in the cost of any service is never welcome, I understand the importance of doing so. I fell very fortunate that we do not receive multiple disruption of services and even in emergency situations your staff is quick to diagnose and safely restore services. I do worry that the seniors on a fixed income will have a difficult time adjusting their budgets to accommodate the extra expense. Thank for allowing us the opportunity to express our opinions.

CPUC Response:

Thank you for this valuable feedback. In preparing the budget for the application, we put considerable thought in increase on typical and low volumes consumers. We try as best we can to find efficiencies and ways to reduce the impact of the increase on our customers as we understand that electricity can be financial strain on a fixed income family. It may be worth noting that CPUC is responsible for approximately 20% or the entire electricity bill. The rest of the bill is controlled by the government.

2. I'm not going to say that I'd be thrilled with a rate increase, but capital projects to a utility are going to benefit everyone in the long run.

CPUC Response:

Thank you for sharing your thoughts. Yes, as our assets age, we need to invest in our infrastructure. We've put a Distribution System Plan together which will be posted on our website once the Ontario Energy Board has approved it. The plan details the condition of our assets and our strategy to maintain them going forward. Our number one priority continues to be the reliability and continuity of service.

3. What are the long and short term financial benefits or cost savings of the proposed "Cost of Service " vs the existing system?

CPUC Response: Investing in assets at a prudent pace helps control unexpected failure and sometimes costly maintenance expenses. On the expense side, having the proper staff in place with respect to succession planning will also pay off in the long run. The current rates are based on 2012 cost and no longer reflect our current costs and assets value therefore it is necessary for us to file this application. Going forward, we will continuously seek ways of finding efficiencies or finding ways of reducing costs where ever possible.

Will the proposed increases in rates be up and above the standard provincial annual increases?

CPUC Response: Every utility in Ontario is on a different Cost of Service schedule and circumstance that would make their rate adjustment different so it's difficult to establish a provincial average. The Ontario Energy Board's role is to make sure that rates approved are just and reasonable. Rate increases above 10% require a rate mitigation plan to minimize the impact on customers.

4. As consumers and businesses owners we are very pleased with the quality of service at all levels offered by the Chapleau Public Utility Corporation.

    CPUC Response: Thank you for your continued support.

5. I think we are lucky to have this locally. Would not be very practical for us to wait for hydro one to travel to Chapleau every time something were to go wrong!

    - There are homes on the outskirts who deal with this. Good point!

6. Is this a short term increase to pay for the upgrades? I agree things need to be upgraded and the money has to come from somewhere but I worry about those on a fixed income or low income families.... how will this affect them with the rising costs of everyday living, food, housing and now hydro.

CPUC Response:

Because Cost of Service ("resetting" of rates) only happens every 5-7 years, this increase won't be temporary. In this application, we have revalued our utility based on the assets in place. As rate payers, we are extremely sensitive to the impact of these rates on our community and customers. With every iteration of our budgets, we considered every alternate options to see if there was a way to reduce rates.

7. Yes I am a senior and we sure do not an increase on a fixed income but thankful to have the service in town.

CPUC Response: Thank you for your kind words.

8. Glad we have service in town the hole gang is awesome there

    CPUC Response: Thank you for your continued support.

9. Although hydro bill increases are never a favourite they are understandable given the amount of maintenance required on an aging system. Thank you for the incredible Customer service. The Chapleau office goes above and beyond.

    CPUC Response: Your support and kind words are very much appreciated.

10. It seems to me expenditures and revenues have been increasing at more or less the same rate over the years except for this year because of the purchase of the new boom truck. As a result there is a $70K shortfall this yr. So, the increase for customers is to cover the shortfall? Why the song and dance with the pretty charts and graphs when you're really just asking us to cover the shortfall caused by the purchase of the truck?

    CPUC Response:

    There is a little more to rate making process (and the increase) than the cost related to the boom truck. There are essentially three major components to a utility's revenue requirement (which rates are based on). 1) capital costs such as the boom trucks 2) the depreciation expense associated with the capital expenditure and 3) Operations, Maintenance and Admin cost. A utility can only recover a rate of return of 6.02% on its capital spending but can recovers 100% of its yearly operation costs. The boom truck + new poles and transformers installed since 2012 represents 25% of the increase from the last cost of service application in 2012. 75% of the increase sought is related to additional Operations, Maintenance and Admin cost since 2012. For the sake of transparency, we want to be upfront and show our customers that there are various components to the increase CPUC is seeking. The full application will be submitted to the Ontario Energy Board shorty and will be posted on our website for your review. Thank you for your sharing your concerns.

11. Firstly, thank you for all your hard work and service.
    Secondly, the change from fixed to variable, is that a local change or provincial. Is it removing the time of use? The 2019 increase from 24$ to 36$ (I think that's what it was), is quite substantial. Is that increase to cover the 2018 boom truck?

    CPUC Response: Please see our previous response with respect to the boom truck for an explanation on how it affects the increase. The change from "fixed and variable" rate to a "fully fixed" rate is mandated by the province (Ontario Energy Board) and only applies to the "delivery" portion of your bill. The electricity portion of your bill which includes the "time of use" rates will not change as a result of this application. CPUC only controls the "delivery" portion of your bill.

12. Sometimes a rate increase is necessary for upgrades but don't ever expect any increases to be temporary.

    CPUC Response: You are correct. A Cost of Service application is essentially an exercise in appraising a utility. As much as we try to minimize costs and the impact on our customers, it makes sense for the value of the utility to increase as we replace poles, meters, wires and vehicles. There would be cause for concern if the value of CPUC were to diminish as it would affect your service and the reliability of our distribution system.

13. je suis très satisfait du service

    CPUC Response: Merci pour vos mots d'encouragement.

14. Will this increase happen every year or will it be locked in for the next 5 years like the last one?

    CPUC Response: The base rates are locked for 5 years minimum (unless something major happens such as the failure of a substation or an "act of god" such as tornado/ice storm…) but every utility in the province can apply for a very small yearly adjustment related to a reduced inflation factor which usually results in approximately 1%-1.5% per year on the "delivery" portion of the bill.

15. You guys do a great job.

    CPUC Response: Thank you for the kind words and support.

16. I'm ok with the raise in price, understand that it needs to be done.

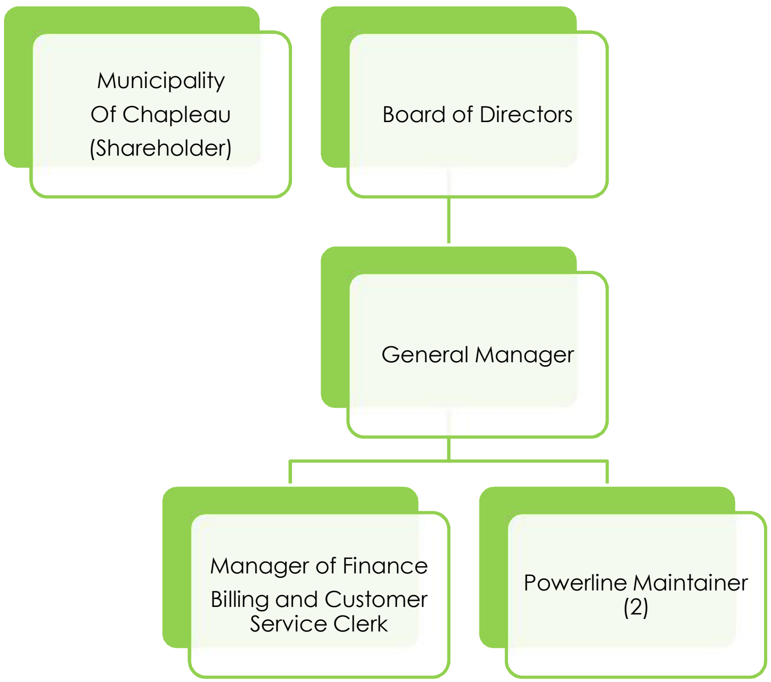
    CPUC Response: Thank you for your support and understanding. We continue to do our best to find efficiencies and ways of reducing the impact of hydro bills all while providing safe and reliable electricity.

Appendix K PowerPoint Presentation

Chapleau Hydro's 2019 Cost of Service (COS) Application

"COST-OF-SERVICE" IS THE SETTING OF A PRICE FOR A SERVICE BASED ON THE COSTS INCURRED IN PROVIDING IT."

Governance and Corporate Structure



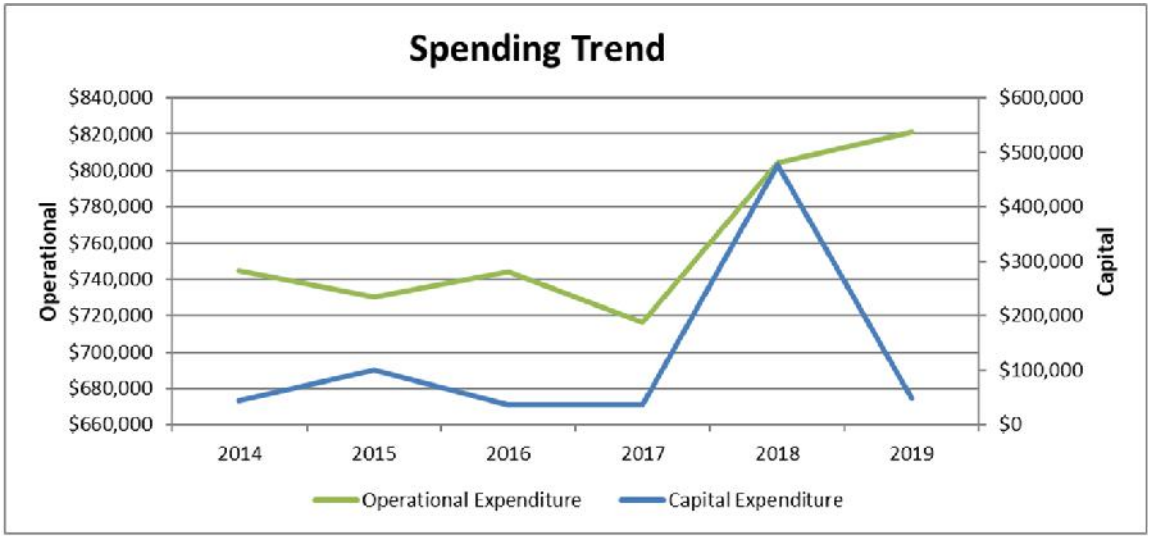
- Utility is owned by the Municipality of Chapleau
- Board Consists of 2 Councillors and 2 Appointed CPUC Customers
- CPUC merged with Energy Services to form one company effective January 2018

The Merger of CPUC & CESC

- Chapleau Public Utilities Corporation employed Chapleau Energy Services Corporation to supply all material, labour and equipment required for the distribution system
- All services were charged to the Distribution Company at a direct cost (no mark-up).
- Risks as identified by the Ontario Energy Board (OEB) included:
  - Increase in administration and regulatory burden
  - Difficulty in getting rates approved by OEB
- Benefits to merging included:
  - Transparency and Openness
  - Better control over costs included in rates

Summary of Capital Assets

	2014	2015	2016	2017	2018	2019
Operational Expenditure	$744,643	$730,565	$744,037	$716,586	$804,404	$821,163
Capital Expenditures	$43,923	$101,176	$36,293	$37,088	$476,662*	$48,144



Capital Projects

2014	2015	2016	2017	2018	2019
Poles and Transformers $18,923	Poles and Transformers $45,854	Poles and Transformers $35,284	Poles and Transformers $4,389	Poles and Transformers $34,352	Poles and Transformers $48,144
Asset Management Software $25,000	Asset Management Planning $54,800	Meter Services $1,000	Meter Sampling $19,668	Station Moisture Testing $32,500	
				Boom Truck $389,010	
				Meter Reverification Computer Hardware $20,800	

Capital Priorities: 2019 & Future

Priorities and strategies for budget development include the following:

Sustain the Existing Distribution System Infrastructure

- Continued Maintenance of two 4.16 KV Transformers
- Replacement of poles and transformers as they show sign of deterioration

Utility Income

	Actual	Actual	Actual	Actual	Projected	Projected
	2014	**2015**	**2016**	**2017**	**2018**	**2019**
Total Operating Revenues	**978,712**	**828,367**	**832,264**	**806,898**	**877,471**	**1,034,496**
Total Expenses	**823,176**	**785,882**	**799,336**	**769,719**	**947,791**	**972,027**
Utility Income before Income Taxes	155,536	42,485	32,928	37,179	-70,320	62,469
Income Taxes	7,050	6,619	8,891	12,042	0	0
Utility Income	**148,486**	**35,866**	**24,037**	**25,137**	**-70,320**	**62,469**

Major Drivers of Operating Costs

2014 to 2019 - an increase of $148,851

- Merging of Energy Services into CPUC
- (CPUC under earning by the end of 2018 due to unsustainable subsidy by CESC)
- Reduced Hydro One call outs to 911 emergencies only
- Increased wages for succession planning
- Increase in outside services for regulatory requirements
- Increase in depreciation with purchase of new truck

Customer Satisfaction Results: 95%

Rating	Responses to survey				
Answer Options	Response Percent	Response Count	Point Allocation	Points Accumulated	%
Excellent	50.7%	77	1	77	
Good	44.1%	67	1	67	
Fair	4.6%	7	0	0	
Poor	0.7%	1	0	0	
		152		144	**95%**

History of Rates and Total Bill Impacts (750 kWh)

Year	Fixed	Variable
2019	$36.69	0.000
2018	$24.04	$0.0140
2017	$24.04	$0.0140
2016	$24.04	$0.0140
2015	$24.04	$0.0140
2014	$23.77	$0.0138
2013	$23.48	$0.0136
2012	**$20.15**	**$0.0135**

- CPUC's Residential Distribution Income
- Fixed rate applied to each monthly bill
- Variable rate applied to each kwh of use
- No variable rate in 2019

Typical Bill Impacts

Customer Class Name	Consumption	Distribution Bill Impact (%)	Distribution Bill Impact ($)	Total Bill Impacts (%)	Total Bill Impacts ($)	Typical Total Bill
Residential	750 kWh	6.22%	$2.15	4.22%	$4.90	$121.13
Residential – RPP/Retailer*	405kWh	23.49%	$6.98	10.06%	$9.42	$103.12
General Service < 50 kW	2,000 kWh	22.26%	$15.80	8.53%	$24.27	$308.82
General Service > 50 to 4999 kW	42,000 kWh	26.33%	$155.77	4.89%	$332.27	$7,132.91
Unmetered Scattered Load	60 kWh	-17.08%	$-4.61	-13.24%	$-4.98	$32.61
Sentinel Lighting	192kWh	78.64%	$12.95	37.90%	$15.22	$55.38
Street Lighting	22,855 kWh	25.55%	$338.36	11.52%	$464.68	$4,496.79

***Retailers are companies that sell energy under contract to households and small businesses.**

We Need Your Feedback

- Your comments will be part of our Cost of Service application to the Ontario Energy Board
- Please email the Chapleau Public Utility Corporation, puc@chapleau.ca

  Or
- OR Comment on our Facebook Page or Twitter

  Or
- Drop in to our offices at 110 Lorne Street South between the hours of 8:30am & 4:30pm, Monday to Friday
- The first 80 responders will receive a free retractable clothesline
- (Only Chapleau PUC Customers are Eligible)

Appendix L Customer Outreach and Communication Plan

CUSTOMER OUTREACH AND COMMUNICATION PLAN 2018-2019

Chapleau Public Utilities Commission

1 Introduction

This plan is provided as a guiding document of the priorities and key tasks that need to be undertaken to bring CPUC's Customer Outreach program closer to the OEB's Renewed Regulatory Framework. This plan supports CPUC's Mission, Vision and Core Values which are presented in the utility's Business Plan.

In addition to addressing the tasks and priorities, this plan also documents the Customer Outreach tools available to CPUC to communicate with various audiences or in case of an emergency.

Note that this document is updated as new information or communication opportunities become available. CPUC commits to treating this plan as a living document to ensure that goals are being met and that the Outreach programs continue to evolve over time.

2 Customer Outreach Priorities

The priorities presented in this section of the plan were recommendations from CPUC's direction following a review of OEB's commitment to Customer Engagement and a review of the Customer Satisfaction Survey completed in spring 2017. The key recommendations will help build the following:

- A strong community outreach campaign to inform CPUC customers of services and offerings
- A strong community outreach campaign to inform CPUC customers of financial transparency
- A strong community outreach campaign to inform CPUC customers robust accountability and oversight of funds and planning.

Detailed explanations of the tasks which support these priorities are presented in the Key Tasks Section.

3 Tasks and Project that Support 2019-2024 Priorities

Completion of Business Plan and Customer Outreach and Communication Plan:

Develop, adopt and implement the Business Plan.

1.1.Communicate effectively and frequently:

Customer base which is well-informed, engaged, motivated, and requires very little ongoing maintenance. Starting in 2019, CPUC plans on publishing a bi-yearly newletter which updates the customer on happenings in the industry as well as the utility. The newsletter would be published on the webstie and on social media and as an insert in the bills.

1.2.Customer Newsletter

With the implementation of CPUC's Newsletter, press releases should only be used for announcements or issues that are newsworthy at a regional importance level.

- Announce Special Events and Meetings
- Announce Rate Applications and Scorecards
- Advertise CDM Programs
- CPUC Emergency Information
- highlight actions taken at the Board meeting, upcoming maintenance and capital projects and community events

1.3.New Logo (2018) and Revamp of Website (2020)

Fresh new visual identity and brand story that strongly portrays values such as trust, confidence, friendliness, caring, reliability, sophistication, etc. Develop, introduce and build a new corporate brand that engenders trust and confidence across all stakeholder audiences, thereby enabling more active engagement and reducing operational costs. The rebranding and Website development has started with a new logo but wil most likely not be comleted until 2020.

Revamp of the Utility's Website: CPUC is planning on revamping its website as part of a broader strategy to engage in new ways with CPUC's customers and partners and to position the company as a more mature utility with innovative and industry-leading business practices. New features of the website include:

- New educational section of the website: The utility has incorporated a new "Electricity

101" section of the website where information of the electricity industry and rate process is presented and explained.

- Significant Projects: The new website also includes an "Information" section where the customer can find a list and details of current capital projects.
- Promotion of Conservation and Demand Management Programs: CPUC has been providing Conservation and Demand Management programs since 2010, actively working with the IESO (formerly the OPA), consultants, government, and other agencies, surrounding regional distributors and customers. Consultations will continue throughout the plan years.

The primary brand messaging strategy for CPUC has been defined as follows:

- A utility that delivers safe, efficient, reliable power.
- A utility that delivers exceptional customer service and outstanding customer experience.
- A utility that is customer-focused, friendly, approachable, and responsive to your energy needs and concerns.
- A utility that is committed to leadership and responsibility in the areas of innovation and environment.

1.4.Social Media Integration:

To engage CPUC customers – both residential and business – by utilizing social media platforms as an additional means/opportunity that effectively connects customers and the community. Social Media is a useful and powerful tool that can be used effectively to help address challenges and reinforce activities undertaken by the utility. CPUC commits to keeping track of its CPUC customer engagement. For example, documenting comments on social media, tracking followers and "likes."

CPUC intends on posting safety and conservation tips, power outages and activities that affect the customers. This includes updates on the replacement of the substation in advance of its next cost of service application.

- Social Media
- Facebook
- Twitter
- Chapleau Public Utilities Corporation

1.5. Publishing CPUC Financial Results:

CPUC commits to developing and communicating transparent and easy to understand information on the financial health of the utility. This includes; Cost of service, rates, delivery, operations, and maintenance. Examples of the "easy to understand" information are;

- Where do revenues go?
- Pie Chart showing sections of the customer invoice.
- Short and concise explanation of capital projects;
- Short and concise ideas on how CPUC is working on finding cost efficiencies.
- Develop a "dashboard" showing proformas for projected years.

1.6. Build community goodwill:

Residents view CPUC as an active and highly respected member of the community, always acting in the best interests of its people, which is reflected back to the shareholder. Build a strong presence and goodwill within the community through active participation in community events.

CPUC intends on hosting a BBQ on an annual basis giving the customers an opportunity to ask queestions and provide feedback on a more casual and informal setting. CPUC intends on offering volunteering during community events such as carnival, Canada Day, fish derby and the Christmas parade.

Annual Open House BBQ for Residential/Businesses

Schedule and yearly open house event. This event is an opportunity to share projects and financial results with CPUC Customers

Career Day/ Safety presentation to local schools/Earth Day

CPUC intends on being more noticeable in its community by starting new programs such as participating in Carrere Day providing information on the types of trades and careers available in the industry as well as skills/education needed CPUC is also planning on doing safety presentations at local schools. The intent is to discuss safety around fallen lines, power outages, vehicles etc. CPUC would also arrange for a community earth day where it would promote energy saving products, energy saving tips, light bulb giveaways, benefits of using a clothesline, ask for customers feedback on what they do for Earth Day.

1.7. Emergency Response Planning via Customer Outreach Plan:

CPUC commits to preparing in an Emergency Response Plan from a Customer Outreach perspective.

CPUC is increasing its communication with its customers with respect to planned and unplanned outage notification via Twitter and Facebook.

The utility will post its outages and as much detail regarding the timing, location, and length of the outage on its website, Facebook, Twitter. Planned outages are communicated directly to the affected customers.

CHAPLEAU PUBLIC UTILITIES CORPORATION

CHAPLEAU, ONTARIO **DATE: AUGUST 30, 2018**

Moved by: ______________________

Seconded by: ______________________

The Board of the Chapleau Public Utilities Corporation hereby certifies that the evidence provided in the August 31, 2018 Cost of Service Application, is accurate, consistent and complete.

Resolution No. 2018 -56

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Chairman