EB-2017-0373
EB-2017-0374

ONTARIO ENERGY BOARD

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 made by the Town of Collingwood for leave to purchase 50% of the issued and outstanding shares of Collingwood PowerStream Utility Services Corp. from Alectra Utilities Corporation, made pursuant to section 86(2)(b) of the Ontario Energy Board Act, 1998 (the "Phase 1 Acquisition");

AND IN THE MATTER OF an application made by EPCOR Collingwood Distribution Corp. for leave to purchase all of the issued and outstanding shares of Collingwood PowerStream Utility Services Corp. from the Town of Collingwood, made pursuant to section 86(2)(b) of the Ontario Energy Board Act, 1998 (the "Phase 2 Acquisition");

AND IN THE MATTER OF an application made by Collus PowerStream Corp., to be effective following the receipt of Phase 1 Acquisition approval from the Board, seeking to include a negative rate rider in the 2017 Board approved rate schedules of Collus PowerStream Corp. to give effect to a 1% reduction relative to 2017 base residential distribution rates (exclusive of rate riders), made pursuant to section 78 of the Ontario Energy Board Act, 1998.

INTERROGATORIES

FROM THE

SCHOOL ENERGY COALITION

1. [Application, p. 7, Sch. D, s. 1.1(ttt)] Please provide a copy of the unanimous shareholders agreement referred to.

2. [p. 8] Please confirm that the last cost of service review of the distributor was in EB-2012-0116. Please provide the achieved ROE, calculated on a regulatory basis, for each year from 2013-2017, and file any forecasts of the Applicants that include ROE forecasts for 2018 and beyond.

3. [p. 8/9] Please confirm that, aside from any Transfer Tax or Departure Tax, the closing adjustments in the EPCOR Agreement are expected to be exactly double the closing adjustments in the Alectra Agreement.

4. [p. 9, 19] Please advise whether the Applicants are seeking an amendment to the distribution licence for the name change in this Application, or in a separate application. Please confirm that the Applicants intend that the distribution licence not be transferred, and that the existing corporation will continue to carry on the distribution business. Please reconcile your response with the statement on page 19 that "EPCOR will carry on and continue the business of CollusLDC".

5. [p. 10, 13, 31] With respect to the Distribution System Plan:

   a. Please confirm that the document entitled "Collus Powerstream Corp. 2018-2022 Distribution System Plan" dated March 15, 2017, and attached to these interrogatories, is the current Distribution System Plan of the distributor.

   b. Please confirm that the Applicants advised the Board by letter dated February 9, 2018 that the DSP was "available for submission", but that it has not yet been filed with the Board.

   c. If this document is the current DSP of the distributor, please file this document on the record in this proceeding. If it is not, please file the current DSP of the distributor.

   d. Please advise the Applicants' proposal for the review of its DSP by the Board.

6. [p. 10] Please provide a detailed estimate, consistent with the DSP, of the expected ICM applications for each year 2019-2023. Please describe how each of the forecast ICM claims are consistent with the principles outlined by the Board in its Decision and Order dated April 5, 2018 in EB-2017-0024.

7. [p. 10] Please provide an up-to-date continuity schedule showing the current balances of each of the regulatory asset and liability accounts, and reconcile those balances back to the most recent financial statements of the distributor.

8. [p. 13] Please advise whether the Applicants agree that the obligation "to meet or exceed current reliability standards for the next five years" should be made a condition of the Board's approval of the Applications.

9. [p. 31] Please provide a breakdown of each of the Status Quo and EPCOR forecasts of OM&A for the years 2019-2024, showing in particular the sources of the proposed cost efficiencies as outlined in the evidence.

10. [p. 31] Please explain why no cost efficiencies are expected in capital spending. In particular, please explain whether any of the OM&A efficiencies will include expenditures that are currently capitalized in part, and whether any of the General Plant expenditures in the DSP can be avoided if the transactions are approved by the Board.

11. [p. 31] Please explain why the 1% negative rate rider is only proposed for residential customers.

12. [Sch. A, Sch. E, s. 1.1(i)(iii)] Please confirm that Collus Solutions Corp. provided services to the distributor and to the Town of Collingwood until December 31, 2016, and that service business was terminated January 1, 2017. If confirmed, please reconcile that response with the definition in the Agreement. Please advise what impacts, if any, were experienced by the distributor as a result of this change.

13. [Sch. C, p. 4] With respect to corporate governance of the distributor post-closing;

    a. Please provide a list of the current directors of EUI.

    b. Please confirm that EUI will be appointing directors for each of EPCOR Ontario, CollusHoldco, and CollusLDC, and that none of the current directors of the distributor, who are resigning on closing, will be retained.

    c. Please advise how many directors will be appointed at each level.

    d. Please advise how many of those directors at each level will be independent of EUI.

    e. Please advise how many of those directors at each level will be based in Ontario.

    f. Please advise at which corporate level (EUI, EPCOR Ontario, CollusHoldco, or CollusLDC) the major decisions affecting the distributor will be made and ultimately approved. If there will be different responsibilities for different types or categories of decisions, please provide a full description of how decisions relating to distribution will be made and approved after closing.

    g. Please provide details on how, if at all, the planned governance of the distributor will be consistent with, or not consistent with, the guidance of the Board proposed in the draft Report of the Board in EB-2014-0255 dated March 28, 2018.

14. [Sch. E, s. 1.1(z)] Please provide a copy of the Confidentiality Agreement referred to.

15. [Sch. E, s. 2.6(a) and Art. X] Please confirm that the Applicants do not expect any Departure Tax or Transfer Tax to be payable in respect of the proposed transactions. If not confirmed, please estimate the amount of any such tax if material.

16. [Sch. E., s. 6.8, DSP p. 72] Please reconcile the provision in the Agreement ($2 million capex per year) with the forecast capital spending in the DSP. If the DSP is not the "current capital plan", please provide the current capital plan of the distributor.

17. [Sch. E, s. 7.2] Please confirm that the role of the Vendor as nominee and bare trustee is intended to ensure that the Applicants can continue to benefit from Infrastructure Ontario funding despite no longer being controlled in Ontario.

18. [Sch. G] Please provide the December 31, 2017 audited financials of Collus Powerstream Corp.

19. [Sch. H] Please provide the December 31, 2017 audited financials of EPCOR Utilities Inc.

20. [Sch. G, p. 12, Sch. H, p. 10] Please advise whether the capitalization and depreciation accounting policies of the distributor are consistent with those of the Purchaser, including but not limited to the useful lives being applied. Please advise whether any changes to accounting policies will occur after the closing date. If the answer is yes (or maybe), please describe the Applicants' proposal for how to ensure that the customers are not subjected to any double-recovery of amounts in rates due to accounting changes.

21. [Sch. G, p. 25] Please provide the accounting order of the Board approving the deferral account for the Sensus ICON meters.

22. [DSP] With respect to the DSP:

    a. Please provide a table showing capital spending by category (with as much detail as possible) for 2013-2017, and forecast for 2018-2022.

    b. Please confirm that the DSP proposes significantly higher capital spending in the future compared to the average for 2013-2017.

    c. For each of the categories of spending in which a significant increase in capital spending is being proposed, please provide an explanation for the increase.

    d. Please advise what involvement, if any, the Purchaser had in the development of the DSP.

23. [General] Attached to these interrogatories is a copy of an article dated February 27, 2018 at the CBC News website describing a judicial inquiry into the sale of 50% of the distributor to Powerstream. Please describe the status of this inquiry, and the implications of this inquiry, if any, on the proposed transactions.

24. [General] Attached to these interrogatories is a news release dated February 21, 2018 on the Town of Collingwood website describing a material billing problem between the distributor and the Town. Please describe the status of this matter, and any implications on the proposed transactions.

Respectfully submitted on behalf of the School Energy Coalition this April 19, 2018.

Jay Shepherd
Counsel for the School Energy Coalition

CBC Investigates

Collingwood calls for judicial inquiry into 'serious questions' about public utility sell-off

Investigation by a judge marks latest chapter as OPP continue probe into multi-million dollar deals with town

By Dave Seglins, CBC News Posted: Feb 27, 2018 6:00 AM ET Last Updated: Feb 27, 2018 9:20 AM ET

Politicians in the booming ski and vacation community of Collingwood, Ont., located northwest of Toronto, are asking a Superior Court judge to step in to investigate the mystery-filled sell-off in 2012 of the town's public power utility.

Town council voted Monday night to invoke a rarely used section of Ontario's Municipal Act to set up a formal judicial inquiry into the sale of a 50 per cent stake in Collus (the Collingwood Utility Services Corp.) to the private company PowerStream.

- OPP probe Collingwood mayor, deputy over bid-tampering allegation

"If critical questions about a massive transaction like this can't be answered then we have problems," deputy mayor Brian Saunderson told CBC News explaining his support Monday for a judicial probe.

"Who benefited? If things were done in such a way that people benefited, then people in this community need to know."

At Monday's meeting, lawyer William McDowell, who was hired by the town, outlined how a judicial inquiry could help answer who benefited from the sale, potential conflicts and where the money from the sale went.

The vote for an inquiry — expected to cost a minimum of $1 million — passed by a margin of 5-1, with Mayor Sandra Cooper the lone dissenter.

Slippery millions, no paper trail

The sale has been controversial from the beginning after the mayor and head of the public utility first trumpeted it as a $15 million windfall for the town. But some on council soon began asking question and discovered a lack of documentation, finding that the buyer, PowerStream, only actually paid $8 million into public coffers.

In 2013, CBC News revealed that the Ontario Provincial Police opened an investigation after citizens formally complained and questioned why Mayor Cooper never disclosed that her brother, former Liberal MP Paul Bonwick, was working directly for PowerStream, as well as other companies doing business with the town.

Cooper told CBC News at the time there was nothing to disclose and that her brother's involvement is not a conflict of interest.

- Collingwood town officials face OPP probe
- Collingwood mayor's brother paid by casino, power companies

Bonwick has acknowledged to CBC News that he was on a monthly retainer with PowerStream providing "strategic advice" on their purchase of the utility from the town. But he declined Monday to discuss the amount of his compensation or the work he performed.

Bonwick has told CBC News in the past that he and his sister, Mayor Cooper, discussed his work as an outside consultant with the town clerk and determined there was no conflict given Ontario's conflict of interest laws do not extend to siblings.

The now-private utility has had even more recent problems, with the town revealing last week that due to a metering problem the utility had been double billing some electricity customers in Collingwood for years to the tune of millions of dollars in overcharges, and is now looking to refund affected customers.

Seeking transparency

Collingwood's current deputy mayor, Saunderson, says the public deserves answers, claiming Mayor Cooper signed off on the 2012 sale of Collus with very little input from others on council or town solicitors.

Saunderson also wonders whether the public got a fair price when initially selling off the 50 per cent share.

"We got $8 million dollars for our shares in the first sale. We've now entered into a second sale for our remaining 50 per cent, where we've realized $12 and a half to 13 million. So that kind of growth over a four or five year period makes you wonder," Saunderson said.

He explains an inquiry, by a yet-to-be appointed judge, could cost in excess of $1 million depending on whether the justice decides to call witnesses or hold public hearings.

But the deputy mayor insists other cities have benefited from shining light on major public expenditures where questions have been raised around contracts, computer leasing or alleged conflicts of interest.

"This is about making sure we fix it so that it can't be done again," Saunderson said. "And if you look at the other public inquiries that have been held across the province, whether it be Toronto, Mississauga or Kitchener, the upshot was — how do we fix things going forward? That's the prime motivation."

Send tips on this story to dave.seglins@cbc.ca.

Published on *Town of Collingwood* (http://www.collingwood.ca)

Home > Collus PowerStream advises Collingwood about electricity overcharging error

Collus PowerStream advises Collingwood about electricity overcharging error

21 February 2018 –The Town of Collingwood recently learned that it has been overcharged in error for electricity consumed at the Town's water filtration plant. Collus PowerStream advised that this overcharging has been ongoing for many years.

The error arose when a second electricity meter, installed in the late 1990's to monitor power consumption related to Collingwood's water distribution system, was billed to the Town of Collingwood in error. Collus PowerStream advises that the overcharging issue has now been corrected.

To date, Collingwood has received a refund from Collus PowerStream in the amount of $410,747.42. The Town continues to explore with Collus PowerStream, any additional customer refund amount associated with the overbilling.

Council will consider options to reimburse those specific water ratepayers affected by the overcharging error.

The Town will provide additional information regarding this matter in due course.

-30-

For more information, contact:

Communications Officer
Jennett Mays
T. 705-445-1030 Ext. 3293
jmays@collingwood.ca

Yes

Source URL (retrieved on *Feb 27th - 11:04 am*): http://www.collingwood.ca/node/17919

COLLUS POWERSTREAM CORP.

2018 - 2022 Distribution System Plan

March 15, 2017

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Introduction

COLLUS PowerStream Corp. ("CPC") is an electricity distributor licensed by the Ontario Energy Board. In accordance with its Distribution License ED-2002-0518, the Applicant provides electricity distribution services in four communities in Simcoe County: Collingwood, Stayner and Creemore (part of Clearview Township) and Thornbury (part of The Town of the Blue Mountains).

This is CPC's first consolidated Distribution System Plan prepared in accordance with Chapter 5 of the Ontario Energy Board's Filing Requirements for Electricity Distribution Rate Applications.

CPC is incorporated under the Ontario Business Corporations Act and is 50% owned by the Town of Collingwood and 50 % owned by PowerStream Inc. PowerStream Inc. purchased their 50% interest on July 31, 2012 (MADD application approved by OEB July 12, 2012).

CPC receives power from Hydro One 44kV feeders and as such is considered an embedded distributor. Revenue is earned by CPC by delivering electric power to the homes and businesses in the service territory. The rates charged for this and the performance standards that the energy delivery system must meet are regulated by the Ontario Energy Board.

As of December 31, 2015, CPC currently serves approximately 16,616 electricity distribution customers across its service area:

<u>Service Connections</u>

Collingwood	12,464
Stayner	1,979
Thornbury	1527
Creemore	648

The Town of Collingwood functions as the major commercial centre for northwest Simcoe County and northeast Grey County. The municipality has experienced a significant shift toward tourist-related service industries since the closure of the Collingwood Steamship Lines (CSL) shipbuilding operation in 1986. Other key large manufacturing losses, specifically affecting electricity demand, include the loss of large electricity users such as Magna and Collingwood Ethanol and load reductions from remaining users such as Pilkington Glass (no longer a large user). Today, Collingwood is a major tourist destination for the Greater Toronto Area (GTA). Collingwood is considered a regional hub for recreation, health care, commercial services and various types of employment. It is a prime tourist destination for both summer and winter recreational activities.

Stayner, Creemore and Thornbury are smaller communities with a mix of residential and light general service customers.

CPC is responsible for maintaining distribution and infrastructure assets deployed over 45 square kilometers (including 354 kilometers of overhead lines and underground lines).

CPC's main objective is to optimize performance of assets at a reasonable cost with due regard for system reliability, public & worker safety and customer service expectations.

CPC's Distribution System Plan documents CPC's asset management processes and capital expenditure plan for the 2018-2022 period. The Distribution System Plan documents the practices, policies and processes that are in-place to ensure that investment decisions support CPC's desired outcomes in a cost effective manner and provides value to the customer.

CPC's Distribution System Plan is designed to support the achievement of the four key OEB established performance outcomes. The Distribution System Plan integrates qualitative and quantitative information which results in an optimal investment plan covering:

- System expansion considerations
- System renewal considerations
- Regional planning considerations
- Renewable generation considerations
- Smart grid considerations
- Customer value considerations
- Public policy considerations

CPC has adopted Good Utility Practices ("GUP") of the electricity distribution industry. This has included adhering to the OEB's Distribution System Code that sets out both good utility practices, minimum performance standards for electricity distribution systems in Ontario, and minimum inspection requirements for distribution equipment. Consistent with good practices, over the years CPC has maintained its equipment in safe and reliable working order and, only when economically justified, upgraded or replaced its equipment. Consistent maintenance of its equipment has permitted CPC to, in some circumstances, extract an extended useful working life from certain assets (i.e. overhead switch maintenance, etc.). Historically, this has been achieved with only a moderate increase in the customers' bills. CPC has been prudent when incurring costs since customer satisfaction survey results indicate that the low price of electricity is an important factor to customers.

By prudently controlling all expenditures and therefore moderating any increases in its customers' bills, the distribution system has evolved into an array of equipment of different vintages spanning a number of technological eras. Funds were not spent on replacing functioning equipment in order to simply have more modern technologies in place.

CPC considers performance-related asset information including, but not limited to, data on reliability, asset condition, loading, customer connection requirements, and system configuration, to determine investment needs of the distribution system.

CPC's DSP demonstrates prudence and rate mitigation consideration in the pacing and prioritizing of discretionary investments, specifically those related to replacement or renewal of end-of-life plant.

5.2 Distribution System Plan

CPC's Distribution System Plan ("DSP") has been prepared in accordance with Chapter 5 of Filing Requirements for Electricity Transmission and Distribution Applications ("Distribution System Plan Filing Requirements"). The DSP reflects CPC's integrated approach to planning, prioritizing, managing assets and includes regional planning, local stakeholder consultations, renewable generation connections and smart grid considerations.

CPC has organized the required information using the section headings in the Distribution System Plan Filing Requirements. Investment projects and activities have been grouped into one of the four OEB defined investment categories listed below, based on the 'trigger' driver of the expenditure:

System access - investments are modifications (including asset relocation) to the distribution system CPC is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via CPC's distribution system

System renewal - investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of CPC's distribution system to provide customers with electricity services.

System service - investments are modifications to CPC's distribution system to ensure the distribution system continues to meet CPC operational objectives while addressing anticipated future customer electricity service requirements

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

The electric distribution system is capital intensive in nature and prudent capital investments and maintenance plans are essential to ensure the sustainability of the distribution network. CPC's Distribution System Plan documents the practices, policies and processes that are in-place to ensure that decisions on capital investments and maintenance plans support CPC's desired outcomes in a cost effective manner and provides value to the customer.

This Distribution System Plan documents the capital and maintenance activities that CPC has completed in the 2013 – 2017 historical period and the 2018 – 2022 forecast period.

The following tables summarize the proposed capital investments (annual $ and % spend) within the four designated categories for the 2018 – 2022 period:

	2018	2019	2020	2021	2022
System Access	$ 581,270	$ 311,956	$ 317,884	$ 323,923	$ 330,078
System Renewal	$ 1,895,340	$ 2,527,530	$ 2,283,120	$ 2,339,224	$ 2,562,300
System Services	$ 51,087	$ 52,058	$ 53,047	$ 54,055	$ 55,082
General Plant	$ 651,930	$ 364,816	$ 657,757	$ 585,755	$ 298,809
Total	$ 3,179,627	$ 3,256,361	$ 3,311,809	$ 3,302,958	$ 3,246,270

	2018	2019	2020	2021	2022
System Access	18%	10%	10%	10%	10%
System Renewal	60%	78%	69%	71%	79%
System Services	2%	2%	2%	2%	2%
General Plant	21%	11%	20%	18%	9%
Total	100%	100%	100%	100%	100%

Table 1 – CPC Capital Investment Summary 2018 - 2022

5.2.1 Distribution System Plan overview

a. Key elements of the Distribution System Plan

It is expected that the operational and service requirements driving CPC's capital expenditures, and found within its DSP, will generally remain consistent through the 2018 to 2022 planning window. CPC's net total capital expenditure over the planning period 2018 through 2022 is forecasted to be $16.5 million, which reflects average annual spends of $3.3 million in 2018 through 2022. The projected expenditures for 2018 and going forward reflect:

- System Access spending to accommodate connections and road authority work;
- Focused planned capital System Renewal investments required to continue replacing aging assets found in CPC's distribution system;
- Minor System Service spending needs to maintain the functionality of the SCADA system;
- General plant spending focused on financial/customer software, hardware, tools and staged replacement of fleet units that are reaching economic end-of-life status over the 2018 – 2022 planning window.
- Rising costs, compared to historical values, due to the impact of the decreasing value of the Canadian dollar on procurement of supplies, services and equipment from sources outside of Canada (e.g. fleet vehicles)

There are a number of key elements that contribute to the determination of the planning investments through the period of the DSP:

Ontario Places to Grow Act – The Town of Collingwood has been identified as a settlement area in the Simcoe Sub-Region. It has not been identified as one of the Urban Growth Centres in the Greater Golden Horseshoe and as such is not the focus of growth covered by the intent of the Act.

Collingwood Community Based Strategic Plan (CCBSP) (2015)

The strategic plan outlines the Town of Collingwood's vision and goals. The CCBSP will be implemented over a 20-year horizon, and includes short, medium and long term action items. Collingwood's population has steadily grown over the last decade and the Town is projected to have a population of approximately 33,000 by 2031.

Town of Collingwood Vision Statement is as follows:

> **Collingwood is a responsible, sustainable, and accessible community that leverages its core strengths: a vibrant downtown, a setting within the natural environment, and an extensive waterfront. This offers a healthy, affordable, and four-season lifestyle to all residents, businesses, and visitors.**

The CBSP Vision expresses five Goals that were defined by the community to be:

- Accountable Local Government;
- Public Access to a Revitalized Waterfront;
- Support for Economic Growth;
- Healthy Lifestyle; and
- Culture and the Arts.

Awareness of the Vision and goals will help guide CPC's future work such that it will complement the Town's strategy.

Town of Collingwood Official Plan (December 2014)

The Town of Collingwood Official Plan establishes goals, objectives, land use, transportation, servicing and community improvement policies to direct the physical growth of the Town of Collingwood. The Official Plan establishes the general pattern for future growth to the year 2021.

The Official Plan framework is based primarily on Collingwood's geographic position as the commercial centre in northwest Simcoe County and as a gateway to Bruce and Grey Counties.

Land use details in the Official Plan reflect the strategic wishes and future needs of the community's residents.

The policies of the Official Plan reflect the long-range land use interests of the Province and County as expressed in the Provincial Policy Statement and County of Simcoe Official Plan.

Town of Collingwood Industrial Land Strategy (2007)

The purpose of this study, undertaken in 2007, was to determine the adequacy of the Town's existing employment land supply based on expectations for growth over a 25 year period and establish an implementation plan for the securing, developing and servicing of employment land in the Town over the longer term. Over 200 acres in Collingwood are designated industrial use however only about a quarter is ready for development.

Town of Collingwood Road Projects – The Town of Collingwood has ongoing road rehabilitation and widening projects some of which may require the relocation of CPC plant.

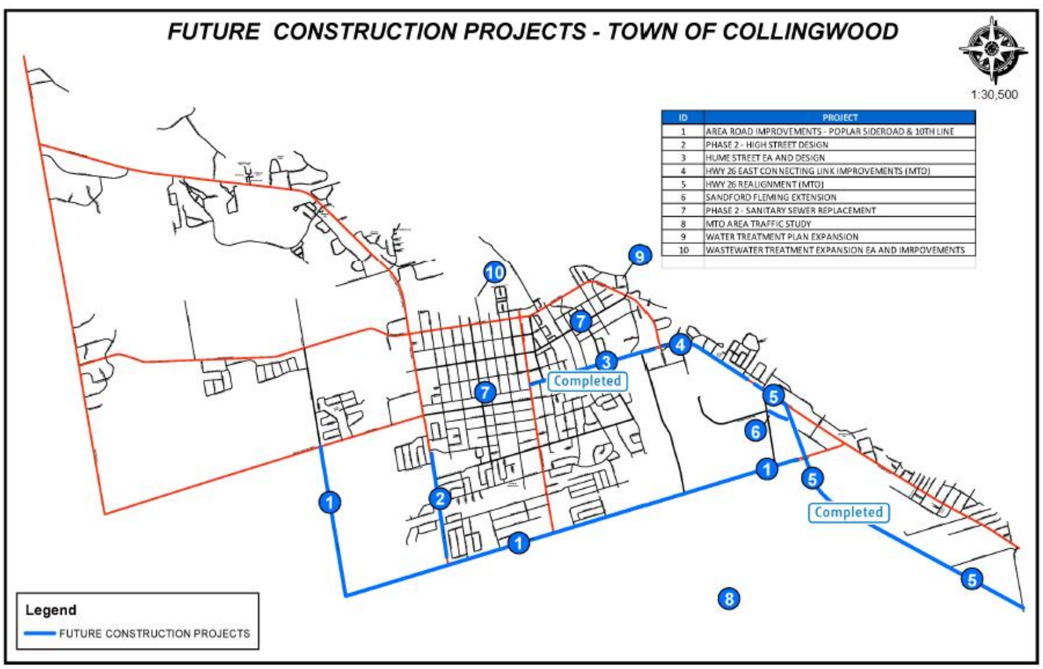

Figure 1 – Future Construction Projects – Town of Collingwood

Simcoe County Road Projects – Simcoe County has not identified any road construction projects in the Town of Collingwood service area (County of Simcoe GIS interactive maps).

Southern Georgian Bay/Muskoka Region Supply Study - CPC is in Group 2 - Southern Georgian Bay/Muskoka region. Study recommendations will likely not impact CPC 2018 – 2022 planning investments.

County of Simcoe Official Plan (2008 – updated 2012) - The Simcoe Official Plan is a document designed to assist in growth management to 2031. The Official Plan establishes density targets that will ensure a greater utilization of existing settlement areas through intensification and infilling so there is less demand on settlement area expansions. Housing growth is directed to existing settlements. Land use policies provide for and encourage the multi-use expansion of settlements, the development of rural business parks and highway commercial development where appropriate. Projections for Town of Collingwood housing availability to accommodate growth to 2031 are noted below:

Town of Collingwood Municipal Residential Land Budget - Summary Results				
Growth Plan Policy Area	**2011-2031**			**Difference** *Potential Unit Surplus at 2031*
	Schedule 7 *Population Growth*	**Demand** *Housing Units Needed*	**Supply** *Unit Potential*	
Delineated Built Boundaries and Undelineated Built-Up Areas	6,886	3,263	4,483	1,220
Designated Greenfield Areas	11,699	4,895	15,961	11,066
Outside Settlement Areas	-	-	-	-
Municipal-wide	18,585	8,158	20,444	**12,286**
This table summarizes the overall results for the local municipal residential land budget. The land budget examines the relationship between demand for additional housing units deriving from Schedule 7 forecast population growth and the municipality's available unit supply. The land supply analysis looks at housing units because this is the variable which requires land. Please refer to the Res-Detailed, Supply and Census Data sheets for more information on the inputs, assumptions and calculations underlying the analysis.	This is the number of additional permanent household residents that will need to be accommodated to meet the Schedule 7 forecast.	This is the number of additional housing units required to accommodate forecast population growth under Schedule 7 plus demand for seasonal and recreational units, not occupied by permanent residents.	This is the future housing unit potential based on currently approved units and additional unit potential through existing planning permissions.	This is the difference between the available unit supply and the anticipated unit demand. If a positive figure is indicated, there is sufficient supply identified to meet forecast demand. If a negative figure is indicated, there is a potential shortage of available supply to meet forecast demand. This is the starting point for evaluating further intensification potential or need for additional urban lands.

Table 2 – Simcoe County – Town of Collingwood Residential Land Budget

OEB 2015 CDM Guidelines – The guidelines were issued in December 2014 and reflect the OEB's expectations with respect to coordination and integration between electricity and natural gas and putting conservation first into distribution planning. CPC is expected to achieve 16.86GWh of CDM savings in the 2015 – 2020 period.

Business Conditions - Collingwood is an employment hub for the South Georgian Bay region. Collingwood, like many communities in south-western Ontario, has been significantly exposed to the manufacturing downturn (and specifically the loss of key anchor industrials such as the Collingwood shipyard, Magna and Collingwood Ethanol). Other businesses have moved into the area. Collingwood's top 5 industry sectors include Health Care, Construction, Advanced Manufacturing and Arts, Entertainment & Recreation. Collingwood's growth rate (2006 – 2014) has been 2x the provincial average which makes it one of the top 10 locations to open a small business in Ontario.

End of life Assets – CPC has identified a need to proactively manage the replacement of assets that are at or near end of life. Age and deteriorating conditions are beginning to affect reliability performance. Replacement plans covering a multiyear period have been developed to begin dealing with key assets at end of life. Replacement plans ensure that planning objectives related to reliability, customer satisfaction and operating cost control are achieved.

b. Sources of cost savings

CPC planning and investment processes follow Good Utility Practice ("GUP") that is executed through the Distribution System Plan. Good utility practices have inherent cost savings represented as avoided costs through sound decision making, thoughtful compromises, right timing and optimum expenditure levels. Some specific CPC Distribution System Plan cost savings/avoided costs are expected to be achieved through the following:

- Plant relocation related to the Town/County road works will be coordinated with Town/County and other utility work schedules to ensure that plant is not replaced prematurely and then replaced again shortly afterwards. Capital contributions from Town/County sources will offset a portion of the total relocation costs. Town/County pays for all costs in excess of like for like and non-standard replacement.
- Testing (i.e. oil testing of power transformers) coordinated with maintenance programs, allows for the efficient use of resources. Pole testing (Resistograph method) will provide more accurate information on pole remaining life to help prepare multi-year replacement plans.
- Proactive maintenance and replacement of plant will reduce reactive maintenance costs and maintain existing customer reliability levels. This will have a beneficial impact on the cost of outages to customers. A structured program will also smooth out financial rate impacts in an effort to avoid disruptive rate spikes to address the volume of plant reaching end of life.
- The use of software (e.g. SPIDAcalc) to optimize plant designs will reduce overdesign and ensure that current CSA standards for non-linear design of pole loading and structural stability are adhered to.
- Coordination of pole, conductor/cable and transformer replacement will reduce overall installation costs through reduced mobilization costs; at the same time transformer sizing can be coordinated to accommodate forecasted renewable generation and/or EV charger deployment. For example, replacement of 5kV underground cable will be coordinated with removal and replacement of live front transformers and poletran units.
- 15kV jacketed TR-XLPE cable is specified for underground subdivisions. Operations at 5kV will result in minimizing electrical insulation stresses thereby potentially achieving an extended life for this type of cable. Using terminations at equipment rather than splices will eliminate potential weak links in the cable system.
- Improved use of the GIS to capture/access plant attribute data (i.e. nameplate data, condition, inspection/maintenance histories, etc.) will aid in cost control through optimization of the asset's lifecycle.
- The application of SmartMAP as a hosted application eliminates direct hardware and IT maintenance costs. SmartMAP provides proactive (e.g. asset management) and reactive (e.g. outage management) benefits to system operations. Enhanced outage documentation and more accurate statistics will result from this initiative. Prudent investment in distribution automation (i.e. remotely operated switches), as part of CPC's Smart Grid development, will improve day to day switching operations and have a positive impact on improving outage restoration times thereby mitigating customer outage costs.
- CPC has attained efficiencies by the pooling of resources and building a strong knowledge based environment, primarily from its involvement with three co-operative organizations – Cornerstone Hydro Electric Concepts Inc. (CHEC Group); Utility Collaborative Services Inc. (UCS); and the Utility Standards Forum (USF).

  - The CHEC Group is an association of 13 LDCs, modeled after a cooperative to combine resources and competencies to best meet the requirements of the changing electrical industry. The CHEC Group is committed to exceeding expectations through the sharing of services, opportunities, knowledge and resources.
  - UCS is a billing and service corporation created to provide members with reliable cost competitive long term software and service solutions. UCS owns the Harris NorthStar electricity, water and sewer billing system. CPC is one of 10 LDCs who work collaboratively on standardization of systems leading to major cost savings for each other. Cost savings through pooled product procurement and utilization are passed directly back to each utility.
  - The use of standards developed through the Utility Standards Forum, significantly reduces unit cost for standard development and equipment approvals. USF is owned by 50 of Ontario's electricity distribution utilities. The cooperative approach to standards development provides members with a consistent, cost effective and ESA approved set of standards. Common material requirements result in readily available stock and economies of scale pricing.
- Meter services (settlements, MSP) are contracted out that result in cost-effective market based rates for services provided.
- PowerStream Inc. co-ownership, through a Master Shared Service Agreement (“MSSA”), is expected to provide synergy savings over the plan period in the following areas:
  - Operations - Control Room After-Hours Dispatch (O&M)
- The use of PowerStream resources to design and deliver CPC’s conservation programs. Collaboration is expected to provide more CDM offerings to CPC’s customer base.
- Mobile equipment (i.e. laptops/tablets) provides paperless access to CPC standards and GIS asset specific information for work crews. Inspection and maintenance forms on the mobile devices facilitate timely and accurate electronic transmission of information versus cumbersome paper processes.
- Pole replacement, in conjunction with 3rd party attachment requests, reduces the overall cost to CPC ratepayers as a result of cost sharing arrangements. This generally affects poles near end of life and/or structurally unable to accommodate the 3rd party attachment in its present form.
- Existing LTLTs where CPC is the geographical distributor will be transferred through service area amendments to the physical distributor. Load transfer customers will become customers of the existing physical distributor as it has been determined by the OEB that this is the most economic efficient approach to serve such electricity consumers.

Activity	Inherent/intangible/avoided cost/other savings
Road relocations	Material and labour saving devices at 50%
Coordinated maintenance and testing	Efficient labour use; optimized asset replacement
Proactive maintenance	Reduced customer outage costs
Design software	Optimized plant design
Pole/conductor/transformer replacement coordination	Reduced mobilization;
15kv insulated UG cable/no splices	Extended service life/minimize cable failure points
GIS asset data repository	Optimized asset lifecycle
Distribution Automation – SmartMAP hosted services	Reduced customer outage costs; hosted savings
Joint Construction Standards development (50 LDCs) - USF	Development and maintenance costs shared
Billing services - UCS	Pooled procurement savings
MSP contracted	Market competitive costs
PowerStream synergies – CDM services	Enhanced offerings to customers
Mobile equipment	Improved data quantity and quality effort
3rd party pole replacements	Cost sharing for pole replacement
LTLTs	OEB assessed savings

Table 3 – 2018 – 2022 Activity savings

The above reflects CPC's ongoing commitment to continuous performance improvement.

Finally, CPC notes that according to PEG's August 2016 benchmarking update published by the OEB, CPC has improved from Cohort 3 to Cohort 2 resulting in a lower stretch factor ranking for 2016 based on improved cost performance. Based on 2015 data, CPC ranks at -13.6% better level of efficiency compared to the model predictions for the 2013-2015 period and as such is considered to be a better than average cost performer (Cohort 2).

c. Period covered by the Distribution System Plan

For the purposes of this Distribution System Plan, 2013 to 2017 is the historical period and the forecast is for 2018 to 2022. 2017 is the bridge year and 2018 is the test year.

d. Vintage of the information

The information generally used throughout the DSP are based on available information established to late 2016, and should be considered as current. Specific variances from this are as noted. CPC statistics based on 2015 RRR filings.

e. Important changes to CPC asset management process

This is the first Distribution Plan filed by CPC and as such there are no changes from any previously filed plan. Previous information with respect to CPC's Asset Management processes, including the 2012 Asset Management Plan, was filed in CPC's 2013 COS application.

Since CPC's last Cost of Service filing in 2013 a Capital investment prioritization process, aligned with corporate and asset management objectives, has been developed to assist in the prioritization of discretionary capital investments. This occurs during the budgeting part of the planning process. During the budget process, capital investments are identified and investment justifications are put together for each one that identifies the cost of the project and its expected benefits. A benefit and Risk deferral assessment of the investment is performed. Investment scores determine an initial priority of the investment for current or future budget periods. Detailed management review of the resulting priority listing may result in investment priority position movement within the 2018-2022 DSP period to accommodate resource availability and available funding.

Asset data quality continues to improve with the population of plant attribute data in the GIS.

f. Contingent activities/events affecting the Distribution System Plan

There are a number of ongoing and future activities in the CPC service areas that may/will impact on capital project prioritization and spending as outlined in the Distribution System Plan.

<u>Customer Connections</u>

Customer connection forecasts are based on timing information received from County and Town Planning staff, planning reports (provincial, regional, municipal), developer submissions and inquiries, and historical connection rates. Variances in connection timing/quantity over the period of the DSP will impact on actual connections and related System Access expenses. If growth accelerates beyond current patterns in the Town of Stayner, then a new MS could possibly be required within the period covered by the DSP. A new MS is not currently planned for in the 2018 – 2022 period.

<u>Town of Collingwood Road Projects</u> – The Town carries out road improvements and road resurfacing on an annual basis. Timing and location for these works is subject to ongoing change. CPC will be required to react to these road projects as they occur during the period of the DSP.

<u>Simcoe County Road Projects</u> – The County has detailed their 2016 Capital Budget for road work. There is no information on post 2016 road works. CPC will be required to react to road project work that affects the distribution plant, as it occurs during the period of the DSP.

<u>Municipal Approvals – UG cable replacement</u>

CPC has identified the need to replace end-of-life underground distribution cable through a multi-year program of spending that has been detailed in this DSP. The timing for annual individual cable replacement projects, forming part of the UG cable replacement program, is contingent upon receiving timely municipal approvals for related excavation work. Projects will be identified and prioritized, through the budget process, in advance and communicated to the Municipality to ensure correct coordination of effort between CPC and the Municipality.

<u>Meter reverification</u>

CPC is required to have its residential type meters tested to ensure compliance with Measurement Canada standards. In 2017, approximately 3,000 of CPC's electronic residential meters will require testing by Measurement Canada compliance sampling methods. If the units pass the sample testing, their seal period will be extended and they can remain in service for the number of years determined by the statistical sampling process. If the units fail sample testing, they will have to be removed from service and replaced by the end of the year they are sampled in (2017). The meter population is divided into 2 groups. It is expected that the meters should pass compliance sampling however any failed groups would result in an unbudgeted capital expenditure in the order of $600,000. The DSP assumes that the meters will successfully pass reverification testing.

5.2.2 Coordinated Planning with third parties

a. Description of the consultations

CPC participates in a number of third party consultations as described below:

Regional Planning - Southern Georgian Bay/Muskoka region

CPC is in Group 2 - Southern Georgian Bay/Muskoka region. The other service providers in this Region are:

- Hydro One Networks Inc.
- Innpower (Innisfil Hydro)
- Lakeland Power Distribution Ltd.
- Midland Power Utility Corporation
- Newmarket-Tay Power Distribution Ltd.
- Orangeville Hydro Limited
- Orillia Power Distribution Corporation
- Parry Sound Power Corp.
- PowerStream Inc. (Barrie)
- Veridian Connections Inc.
- Veridian-Gravenhurst Hydro Electric Inc.
- Wasaga Distribution Inc.

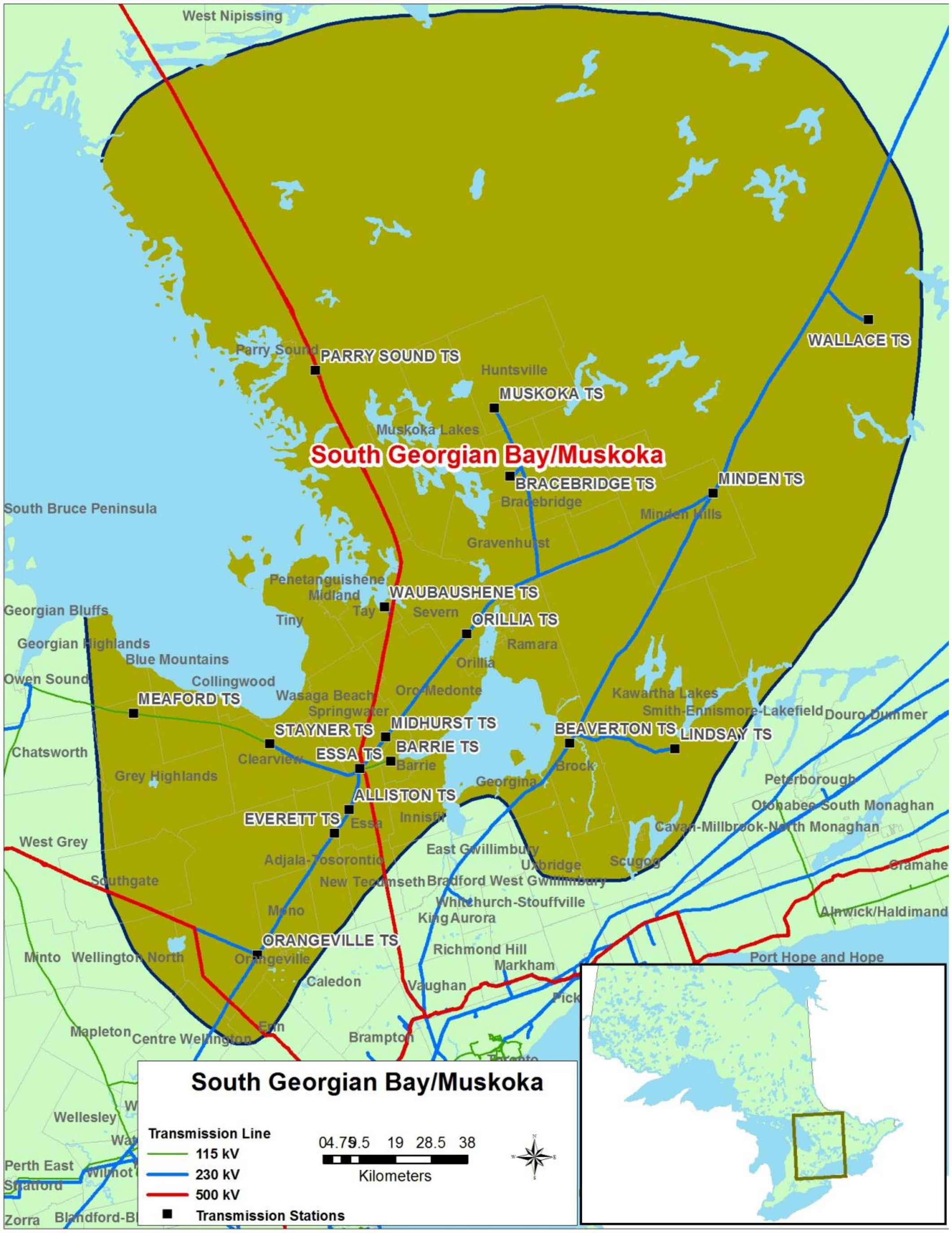

Figure 2 – Southern Georgian Bay/Muskoka Region

This region was scheduled for the 2014-2015 planning cycle. Information gathering started in October, 2014 and the Needs Assessment Report was completed in March 2015. During information gathering, CPC provided its load forecasts for its service area to Hydro One for incorporation into the Needs Assessment process. The load forecast show that CPC is winter peaking. The load forecasts for winter and summer are shown in Tables 4 and 5 below:

South Georgian Bay - Muskoka Region - Embedded LDC Load Forecast

Summer Peak Load													
Transformer Station Name	Embedded Supply Point(s)	Historical MW				Forecast Gross MW (Before CDM)							
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Meaford TS	*Thornbury PME*	3.77	3.91	3.55	5.24	3.62	3.66	3.70	3.73	3.77	3.81	3.85	3.89
Stayner TS	*Collingwood - Aggregate*	44.21	40.49	38.85	40.15	39.63	40.03	40.43	40.83	41.24	41.65	42.07	42.49
Stayner TS	*Creemore*	1.70	1.91	1.75	1.82	1.78	1.80	1.82	1.84	1.85	1.87	1.89	1.91
Stayner TS	*Stayner - Aggregate*	5.32	5.54	4.98	5.16	5.08	5.13	5.18	5.23	5.28	5.34	5.39	5.44

Table 4 – CPC Summer Peak Load Forecast

South Georgian Bay - Muskoka Region - Embedded LDC Load Forecast

Winter Peak Load													
Transformer Station Name	Embedded Supply Point(s)	Historical MW				Forecast Gross MW (Before CDM)							
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Meaford TS	*Thornbury PME*	4.38	4.51	4.85	4.90	4.95	5.00	5.05	5.10	5.15	5.20	5.25	5.31
Stayner TS	*Collingwood - Aggregate*	45.31	42.55	44.24	44.69	45.13	45.59	46.04	46.50	46.97	47.44	47.91	48.39
Stayner TS	*Creemore*	2.18	2.34	2.44	2.46	2.49	2.51	2.54	2.56	2.59	2.61	2.64	2.67
Stayner TS	*Stayner - Aggregate*	5.35	5.85	5.95	6.01	6.07	6.14	6.20	6.26	6.32	6.38	6.45	6.51

Table 5 – CPC Winter Peak Load Forecast

A South Georgian Bay/Muskoka Region Scoping Assessment Outcome Report was published in June 2015. In the report, the Regional Participants identified two sub-regions – Barrie/Innisfil and Parry Sound/Muskoka—that require regional coordinated planning and are proposing that two Working Groups be established to undertake Integrated Regional Resource Plans (IRRP) for each sub-region to address the needs in these areas. CPC is outside of both these sub-regions as it was determined that local needs can be addressed through local planning between the transmitter (HONI) and CPC. CPC is taking no further part in the IRRP process.

The IRRPs (to be issued in Q4 2016) are expected to have no impact on the 2018 – 2022 DSP.

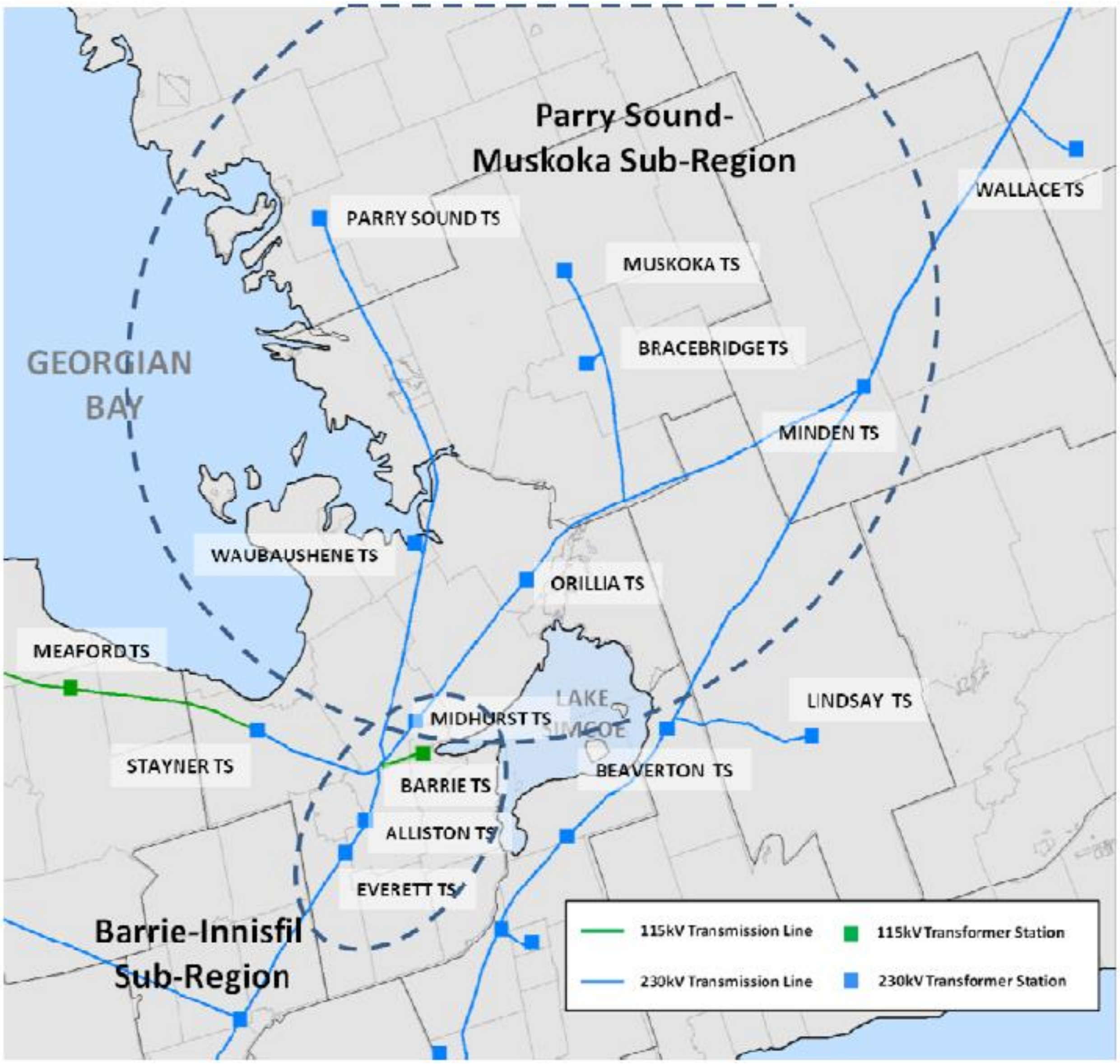

Figure 3 – Barrie-Innisfil/Muskoka Sub-Regions

Customer Consultations

CPC keeps in contact with its customers generally through meetings and discussions that arise usually in the context of new loads anticipated, opportunities for improvement of performance or events that have occurred that affected them.

The IESO FIT/microFIT programs and CPC's CDM programs, delivered through PowerStream Inc., result in almost daily consultation with customers regarding program information and required customer actions to take advantage of these programs.

CPC conducts customer satisfaction surveys on a periodic basis. Surveys show that the customers are very satisfied with CPC's service. CPC reviews the survey results to determine if adjustments to corporate programs and strategies are warranted.

The 2014 UtilityPULSE Customer Satisfaction Survey included questions to residential and commercial customers to determine their preference with respect to issues such as Outage Communications and Prioritizing Investments. This was used to determine level of ratepayer support for CPC's plant investment position in the DSP that is designed to maintain existing service levels. This level of ratepayer support for plant investment is a key driver of DSP investments over the 2018 – 2022 planning period.

Large User consultation

Every Thursday, an electronic newsletter is sent to CPC's large users. It provides information on electricity and TOU pricing, safety issues, emergency preparedness and other matters of general interest to the consumer.

Other Consultations

CPC consults with its neighbouring utilities, such as Hydro One Distribution and the CHEC group, on various matters such as joint use on poles, mutual assistance during severe weather incidents, LTLT resolution, etc. The CHEC Group is an association of 13 LDCs, modeled after a cooperative to combine resources and competencies to best meet the requirements of the changing electrical industry. The CHEC Group is committed to exceeding expectations through the sharing of services, opportunities, knowledge and resources. The CHEC group meets 2 – 4 times a year to discuss Operational matters. For example, the most recent meeting discussed a number of items including member's plans to eliminate their LTLTs by the June 21, 2017 deadline.

Town of Collingwood Emergency Plan

The Town has an Emergency plan and CPC are participants in the Town's Municipal Control Group (i.e. participate in the Annual training / exercise and provide Utility specific info). CPC also participates with the CHEC group in their members' emergency planning.

b. Final deliverables of the Regional Planning process

A South Georgian Bay/Muskoka Region Scoping Assessment Outcome Report was published in June 2015. The Integrated Regional Resource Planning (IRRP) Terms of Reference for the Parry Sound/Muskoka sub-region is expected to be released in Q4 2016.The IRRP is not expected to have any impact on the 2018 – 2022 DSP.

c. HONI and IESO comment letters

CPC has requested and received comment letters from HONI and the IESO with respect to:

1. Status update on Regional Planning initiatives;
2. CPC REG investment plans.

Comment letters are shown in Appendix D

5.2.3 Performance Measurement for continuous improvement

a. Metrics used to monitor distribution system planning performance

CPC has been and continues to be, focused on maintaining the adequacy, reliability and quality of service to its distribution customers. CPC reviews plan performance on an ongoing basis through various mechanisms such as:

Customer oriented performance - Customer survey

On a periodic basis, CPC undertakes a customer satisfaction survey to obtain feedback on the overall value of service offered to customers. Customers (residential and commercial) are engaged to provide high level feedback on their perceptions of CPC performance and where they think CPC could improve service.

Customer oriented performance - Service Reliability

Service reliability issues (i.e. Trouble Calls), as noted in crew Field & Time Reports, are reviewed by the VP Operations on a daily basis. Control Room logs are also received that cover any after-hours calls received by PowerStream Inc. Control Room staff who provide after-hours call answering service for CPC. Meetings and discussions are held to review issues of an exceptional nature.

OEB defined baselines will be used to compare rolling 5 year averages for SAIDI and SAIFI (excluding loss of supply and major event days). Current baselines are based on 2010-2014 reliability performance and will remain in place for most of the DSP period. The baselines are used as targets for reliability performance expectations in the current year. SAIDI and SAIFI are defined as:

SAIDI = System Average Interruption Duration Index

$$= \frac{\text{Total Customer-Hours of Interruptions}}{\text{Total Customers Served}}$$

SAIFI = System Average Interruption Frequency Index

$$= \frac{\text{Total Customer Interruptions}}{\text{Total Customers Served}}$$

CPC also monitors CAIDI, another standard reliability index. CAIDI is defined as:

CAIDI = Customer Average Interruption Duration Index

$$= \frac{\text{SAIDI}}{\text{SAIFI}}$$

These indices provide CPC with an annual measure of its service performance for internal benchmarking and for comparisons with other distributors. In accordance with Section 7.3.2 of the OEB Electricity Distribution Rate Handbook, CPC records and reports SAIDI and SAIFI figures annually.

Beginning in 2014 all outages are classified according to cause code, as per OEB reporting requirements, to provide further insight into the root cause of the outage.

Code	Cause of Interruption
0	**Unknown/Other** Customer interruptions with no apparent cause that contributed to the outage.
1	**Scheduled Outage** **Customer interruptions** due to the disconnection at a selected time for the purpose of construction or preventive maintenance.
2	**Loss of Supply** Customer interruptions due to problems associated with assets owned and/or operated by another party, and/or in the bulk electricity supply system. For this purpose, the bulk electricity supply system is distinguished from the distributor's system based on ownership demarcation.
3	**Tree Contacts** Customer interruptions caused by faults resulting from tree contact with energized circuits.
4	**Lightning** Customer interruptions due to lightning striking the distribution system, resulting in an insulation breakdown and/or flash-overs.
5	**Defective Equipment** Customer interruptions resulting from distributor equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance.
6	**Adverse Weather** Customer interruptions resulting from rain, ice storms, snow, winds, extreme temperatures, freezing rain, frost, or other extreme weather conditions (exclusive of Code 3 and Code 4 events).
7	**Adverse Environment** Customer interruptions due to distributor equipment being subject to abnormal environments, such as salt spray, industrial contamination, humidity, corrosion, vibration, fire, or flowing.
8	**Human Element** Customer interruptions due to the interface of distributor staff with the distribution system.
9	**Foreign Interference** Customer interruptions beyond the control of the distributor, such as those caused by animals, vehicles, dig-ins, vandalism, sabotage, and foreign objects.

Table 6 – Causes of Interruption Codes

Tracking outage performance by cause code provides valuable information on specific outage causes that need to be addressed to improve negative trending. As with the reliability indices, the past historical performance range is used as a target and results outside this range indicate positive or negative trending. At the present time historical information on cause codes is limited to data from 2014 onwards.

<u>Customer oriented performance - Bill impacts</u>

Over 75% of a customer's bill is due to factors (i.e. generation, transmission, global uplift, etc.) outside the control of the LDC. Notwithstanding that, surveys indicate that it is the overall cost of the bill, not the individual components, that are of concern to the customer.

CPC considers the short and long term customer bill impacts as part of the asset management process and bill impact mitigation is a consideration in investment planning decisions. Where possible, CPC's forward looking asset management plans and programs are structured to smooth customer bill impacts over the years. This is especially evident in discretionary programs, such as asset refurbishment/replacement, where Risk and rate mitigation inputs are considerations to program scheduling. While the majority of investment scheduling can be smoothed, specific capital expenditures, such as large Line Trucks, are individually expensive items which may result in small expenditure spikes in a specific year.

Customer oriented performance - Billing accuracy

In CPC and other utility surveys, billing related issues have been identified as a key identifier of customer satisfaction. When billing is wrong, adjustments have to be made to provide the customer with a corrected bill. Sometimes there is a disconnect between what the customer perceives to be a billing problem and what CPC considers to be a billing problem. Employee training helps deal with the problems that cause the most concern with customers. Billing accuracy reduces disputed bill re-work, delayed payments and improves customer confidence. Billing is one of the principal forms of communication with the customer.

Cost Efficiency and Effectiveness – Project/program variance analysis

CPC monitors capital projects and maintenance program spending. Going forward, for material capital projects, actual costs are to be compared to estimates and variances exceeding designated thresholds will require detailed explanation by operating staff that executed the project and engineering staff that planned the project. The performance measure is that these projects and programs are completed within the budget year unless carryover spending has been specifically identified. Planned maintenance programs are expected to be completed within the budget and calendar year.

Cost Efficiency and Effectiveness - DSP Spending Progress Report

CPC will be monitoring its execution of the projects and programs included in the DSP. On an annual basis, CPC will calculate for that year, and on a cumulative basis for the five years of the DSP, its actual capital spending compared to the approved capital budget.

Asset/System Operations Performance – Reg. 22/04

As with every other Ontario distributor, CPC's design, construction, inspection, maintenance practices are audited on a yearly basis as required by Ontario Regulation 22/04. The utility can be deemed to be in one of three performance categories:

1. In compliance
2. Needs Improvement
3. Not in compliance

CPC's target is to remain in compliance in all categories being audited.

Asset/System Operations Performance –Substation loading

CPC's municipal substations have been identified as being single most critical asset category within its distribution system. CPC looks to maintain substation normal loading at approximately 75% of the ONAN (Oil Natural Air Natural) MVA capacity of the substation transformer. CPC deems this a reasonable operating philosophy in that the use of the asset is optimized and overload capacity exists for contingency situations. Substation loading information is collected and reviewed on a monthly basis. The substation loading indicates the effectiveness of CPC's asset utilization planning.

Asset/System Operations Performance –Feeder loading

As part of CPC design and operating philosophy, 4kV and 44kV feeders are loaded to 50% of capacity to ensure that contingency situations can be addressed with the minimal amount of service interruption to the customer. Most MS feeders are sized to handle up to 600 Amps maximum load. Feeder loading is collected and reviewed on a monthly basis. The feeder loading indicates the effectiveness of CPC's asset utilization planning and contingency capability.

Asset/System Operations Performance – System Losses

CPC system losses are monitored annually. System design and operation is managed such that system losses are maintained within OEB thresholds as defined in the OEB Practices Relating to Management of System Losses. Losses are monitored to ensure that the OEB 5% threshold is not exceeded.

RRFE Performance Scorecard

The OEB RRFE performance scorecard is reviewed annually to ensure performance trending aligns with the overall corporate business strategy and objectives, as well as regulatory targets. Underperformance trending would result in measures being taken to realign performance trending with expectations.

b. Summary of historical performance and performance trends

Customer oriented performance - Customer survey

Within range of the historical period, CPC has had three customer surveys performed by UtilityPULSE; one in 2010, one in 2013 in conjunction with the Cornerstone Hydro Electric Concepts (CHEC) Group and one in 2014. The two customer survey results are shown in the table below:

	2010	2013	2014
Customer Care	A	B+	B+
Company Image	A	A	A
Management Operations	A	A	A
Customer Centric Engagement Index (CCEI)	-	86%	80%
Customer Experience Performance rating (CEPr)	-	87%	84%

Table 7 – 2010, 2013 & 2014 Customer Survey Results

The survey results indicate consistent customer perception of CPC key performance categories of Company Image and Management Operations. The survey result for Customer Care decreased slightly in 2014 reflective of increased need to answer inquiries promptly, provide sound information and keep customers informed. It is also reflective of the impact of the 2013 Ice Storm on customer communication effectiveness perceptions. In all surveys, CPC scored at or higher than National and Ontario benchmarks in all three performance categories. New categories introduced in the 2013 Customer Survey provide specific feedback on customer interaction perceptions and their engagement connection with the CPC brand. CPC's performance in this area exceeds National and Ontario performance.

CPC also participated in the Cornerstone Hydro Electric Concepts (CHEC) Group, of which it is a member, 2017 Customer Satisfaction survey performed by Redhead Media Solutions Inc. Key survey results are shown in the table below:

	2017
Services provided satisfaction	77%
Reliability satisfaction	88%
Bill accuracy satisfaction	75%
Customer Service satisfaction	53%
Communications satisfaction	62%
Overall Customer Satisfaction Index score	71.8%

Table 8 – 2017 CHEC Group Customer Survey Results

Customer oriented performance - Service Reliability

The CPC interruption history for all interruptions and interruptions excluding loss of supply are shown in Figure 4 (2016) and Table 9 (2013 – 2016) below:

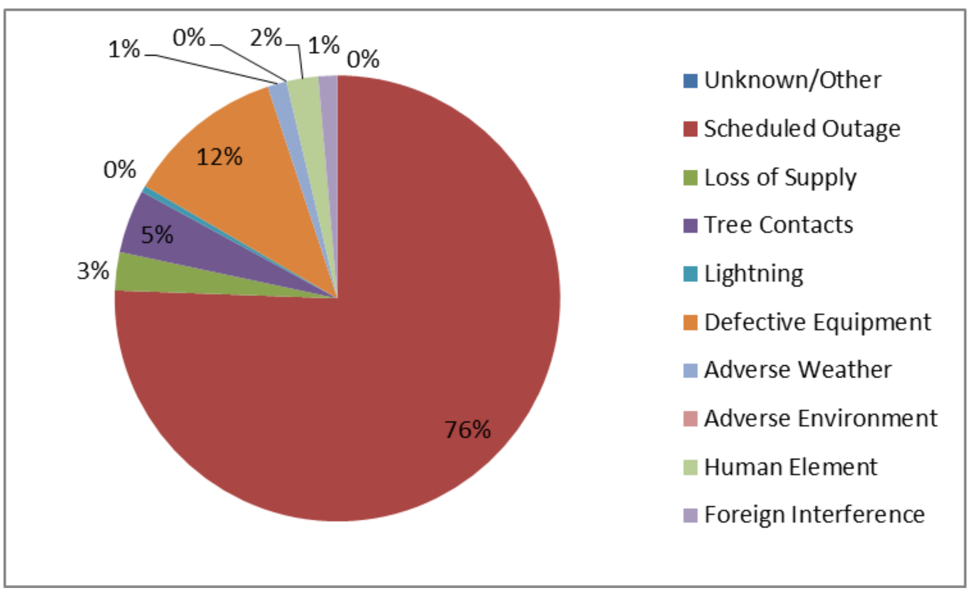

Figure 4 - 2016 Outages by Type

Year	All interruptions	% of total interruptions due to Loss of Supply	All interruptions excluding Loss of Supply
2013	61,820	81%	11,891
2014	15,741	34%	10,424
2015	19,616	26%	14,541
2016*	30,921	25%	23,340

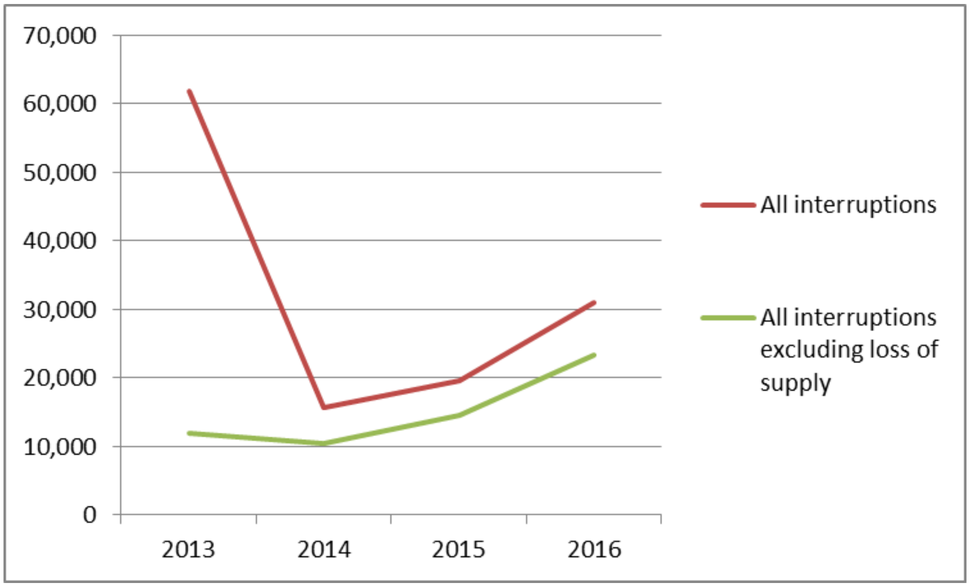

Table 9 – 2013 – 2016 Interruption history

*2016 data is as of end of October 2016. Service reliability statistics are compiled monthly (see sample reliability statistics summary in Appendix B).

The 2013 - 2016 interruption history table shows the significant impact of Loss of Supply on overall reliability. HONI Improvements to the supply from Stayner TS in 2014 is reflected in lower percentage of interruptions due to Loss of Supply in the 2014 through 2015 figures. Increase in 2016 interruption count due to major storm in October.

In 2015, continuing on into 2016, CPC saw a significant increase in the number of and duration of Scheduled Outages as a result of a major project initiated by Bell Canada who is installing Bell Fibre throughout CPC's service territory. In 2015 there were a total of 176 scheduled interruptions affecting 4,114 customers for a total of 14,115 customer hours of interruptions. As a comparison, in 2014 there were a total of 98 scheduled interruptions affecting 1,430 customers for a total of 258 customer hours of interruption.

CPC's SAIFI, SAIDI and CAIDI statistics for the 2013 – 2016 historical period are shown below:

Year	SAIFI	SAIDI	CAIDI
2013	3.81	1.78	0.47
2014	0.95	0.03	0.03
2015	1.19	2.77	2.32
2016*	1.84	5.58	3.03

Table 10 – 2013 – 2016 Reliability Statistics

Increase in 2016 SAIDI and SAIFI due to major storm in October that will be treated as an MED.

Without the loss of bulk supply and 2016 October MED, the statistics would be as follows:

Year	SAIFI	SAIDI	CAIDI
2013	0.73	0.10	0.14
2014	0.63	0.03	0.05
2015	0.88	2.36	2.68
2016*	1.02	1.70	1.67

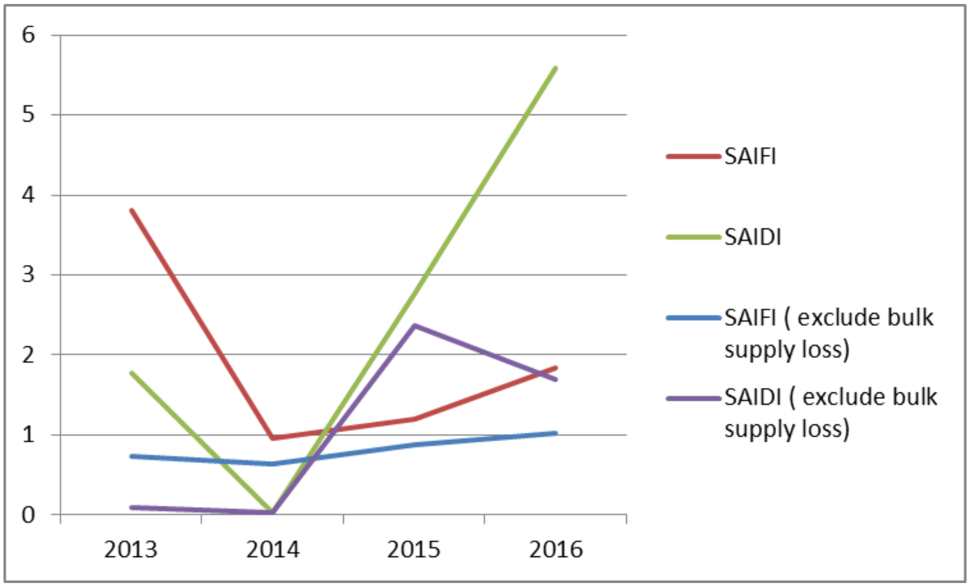

Table 11 – 2013 - 2016 Reliability statistics – Bulk loss of supply excluded

*2016 data is as of end of October 2016. The reliability statistics, excluding loss of bulk supply, indicate a relatively stable trending over the historical period.

SAIFI has been averaging approximately 1.94 over the historical period. This equates to a CPC customer experiencing an outage once every 11 months. This performance compares favourably with the OEB published Ontario performance figure of 2.26 (2010 – 2014 average - no Major Event Days (MED); Code 2 included).

SAIDI has been averaging approximately 2.54 over the historical period. This equates to a CPC average of 152 minutes of outages per customer. This performance compares very favourably with the OEB published Ontario performance figure of 5.14 (2010 – 2014 average – no MED; Code 2 included).

CAIDI has been averaging approximately 1.46 over the historical period. The key contributor to this number is the increase in planned outages throughout 2015. This performance compares very favourably with the OEB published Ontario performance figure of 2.27 (2010 – 2014 average – no MED; code 2 included).

Historical outage causes are listed below:

Code	Primary Cause	2013	2014	2015	2016*	Average
0	Unknown/Other	-	6	8	0	5
1	Scheduled Outage	-	98	176	164	146
2	Loss of Supply	-	3	5	6	5
3	Tree Contacts	-	8	1	10	6
4	Lightning	-	1	0	1	1
5	Defective Equipment	-	29	25	25	26
6	Adverse Weather	-	9	5	3	6
7	Adverse Environment	-	0	0	0	0
8	Human Element	-	9	5	5	6
9	Foreign Interference	-	3	2	3	3

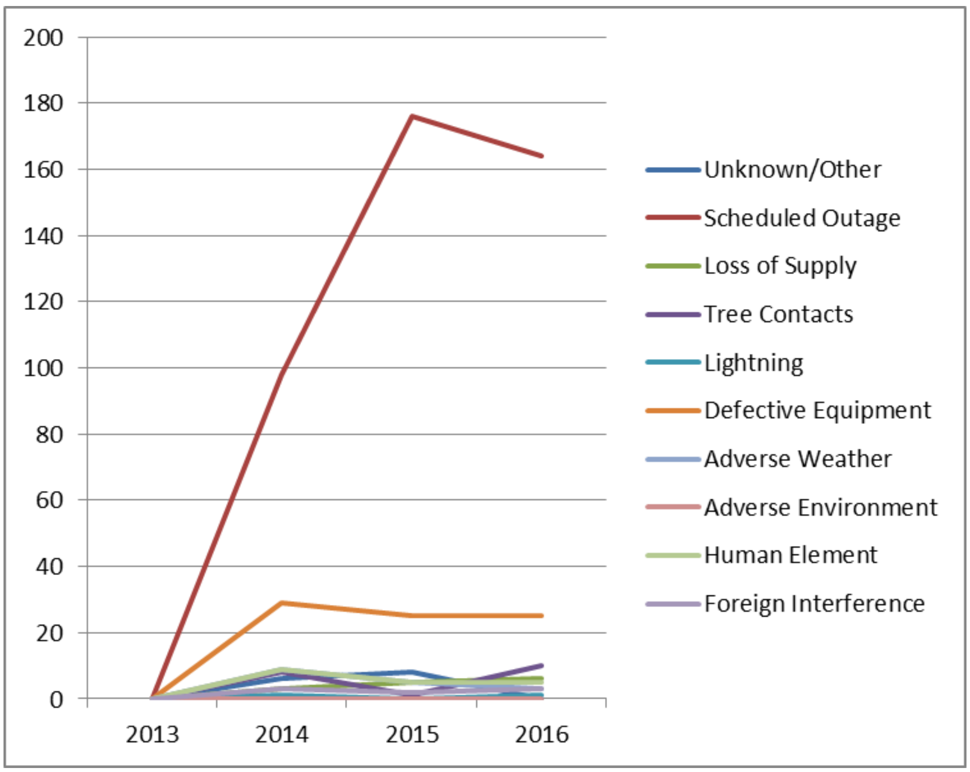

Table 12 – 2014 – 2016 Outage causes

*2016 data as of end of October 2016

CPC started collecting reliability statistics by cause code beginning in 2014. No information has been compiled, by cause code, for 2013. There has been a considerable increase in scheduled outages primarily due to the need to replace plant to accommodate 3rd party (Bell multi-year fibre installation project) attachments.

Code 1 outages are high due to need to schedule outages to accommodate significant third party (Bell) pole work in 2015 and 2016.

Code 3 outages, tree contacts, show an oscillating trend. Code 3 outages are mitigated through effective tree trimming programs to maintain line clearance standards.

Code 5 outages, defective equipment, show a neutral trend. Code 5 outages are mitigated through effective maintenance programs and renewal programs for assets at end of useful life.

Code 6 outages, adverse weather, show a decreasing trend. Code 6 outages are mitigated through efforts to climate harden the distribution system.

Code 8 outages show a decreasing trend. Code 8 outages are mitigated through improved training and records information.

Code 9 outages, foreign interference, show a neutral trend. Some Code 9 outages (i.e. animal contact) are mitigated through increased use of barriers and environmental design considerations. Other Code 9 outages (i.e. vehicle impacts) are more difficult to mitigate.

Customer oriented performance - Bill impacts

Over the historical period, CPC residential, GS<50 and GS>50 customers have had an average annual distribution component rate increase, since CPC's 2013 Cost of Service application, of 5.12%, 6.42% and 11.27% respectively (2014 – 2016). The averages reflect a significant reduction in variance account refunds to customers beginning in 2014. Excluding variance accounts, the distribution component annual averages are -1.24%, -1.22% and 1.6% respectively.

Customer oriented performance - Billing problems

CPC has received general feedback on billing accuracy through the annual customer survey. Annual statistics are shown below:

	CPC	National	Ontario
2010	11%	10%	12%
2014	15%	16%	25%

Table 13 - Percentage of respondents indicating a billing problem in the last 12 months

CPC performance has been near to or exceeded Ontario and National performance levels in the two surveys undertaken.

CPC's calculated billing accuracy for 2014, as part of its annual RRR filing, was 99.94%.

Cost Efficiency and Effectiveness – Project/program variance analysis

In 2014, CPC completed 71% of planned capital projects while in 2015, it completed 50% of planned capital projects. The decline in project completion CPC experienced can primarily be attributed to low line staff levels due to absences and staff turnover. Throughout 2016, CPC has reacquired a full complement of line staff to complete the 2016 and future capital plans. CPC budget to actual spending will also be monitored going forward through detailed variance analysis reporting to accumulate improved data on infrastructure installation costs (e.g. unit pole installation costs).

Cost Efficiency and Effectiveness - DSP Spending Progress Report

As this is the first DSP filing, there are no historical statistics.

Asset/System Operations Performance – Reg. 22/04

CPC has achieved compliance in this portion of the audit each year since the regulation came into effect in 2004. Issues noted as “Needs Improvement” are addressed to ensure that they are “In Compliance” for the following year audit. Exceptions to “In Compliance” audit findings are shown in the table below:

Audit Year	Not in Compliance	Needs Improvement
2013	0	0
2014	0	1
2015	0	0

Table 14– 2013 – 2015 ESA Audit Results

Audits are performed in the following year. For example, the 2014 audit was done in the period May 1 – 30, 2015. The 1 Needs Improvement in 2014 reflected a documentation error versus an actual process issue. CPC has adopted a target of “zero” non-compliance and “zero” needs improvement as a performance benchmark for the period of the DSP.

Asset/System Operations Performance –Substation loading

The CPC service area is winter peaking. All MS peaks shown in the chart below are non-coincident.

MS Name	Capacity (MVA)	2016 Peak Load (MVA)	Avg % Utilization
Collingwood MS1	6/6.7	4.6	77
Collingwood MS2	8	4.7	59
Collingwood MS3	3 /3.4	2.0	67
Collingwood MS4	5/5.6	3.7	74
Collingwood MS5	10	3.7	37
Collingwood MS6	6/6.7	3.9	65
Collingwood MS7	5	2.6	52
Collingwood MS8	4	1.1	28
Collingwood MS9	10.67	4.0	37
Collingwood MS10	6	1.5	25
Stayner MS1	5	2.4	48
Stayner MS2	5	2.1	42
Thornbury MS1	6	2.5	42
Thornbury MS2	5	1.6	32
Total	84.67	40.4	48

Table 15– CPC 2016 Substation loading

Average station utilization is at 48%. The CPC service area loading demonstrates the relatively stable nature of a low load growth area.

Asset/System Operations Performance –Feeder loading

4.16kV and 8.32kV feeders loading is shown in section 5.3.2(d). There is considerable capacity on the 4.16kV and 8.32kV feeder systems to accommodate incremental load growth (i.e. electric vehicles).

Asset/System Operations Performance – System Losses

CPC system losses over the historical period are shown below:

2013	2014	2015
5.6%	3.7%	4.93%

Table 16 – CPC System Losses

Losses are trending in the 3.7 – 5.6% range over this historical period and within the OEB 5% threshold. The high value in 2013 is due to the use of HONI M1 feeder which was heavily loaded and not optimized for CPC's system. In 2014 the feed was switched to the HONI M7 feeder which reduced losses.

RRFE Performance Scorecard

The RRFE performance scorecard metrics indicate that CPC is effective in achieving RRFE performance outcomes. Most measures show historical performance is within target values. The OEB has ranked all Ontario LDCs in one of five efficiency groups (1 – 5) with Group 1 being deemed the most efficient and Group 5 being deemed the least efficient. CPC is currently ranked in Group 2 with respect to Efficiency Assessment (stretch factor = 0.15%).

c. Effect of performance information on the plan

The results of the performance measures are a contributing factor in determining the direction and investment priorities of the Distribution System Plan.

Customer Survey Results

CPC conducts customer satisfaction surveys on a periodic basis. Surveys show that the customers are generally satisfied with CPC's overall performance. CPC reviews the survey results to determine if adjustments to corporate programs and strategies are warranted. Any significant change to program/strategies would affect the DSP. The most recent (2017) survey indicates a need to focus on improving Customer perceptions of CPC's Customer Service and Communications performance.

From an overall industry perspective, a majority of customers (88%) prefer the telephone as their primary communication channel with their LDC indicating that investments in other channels of communication over the period of the DSP should be considered only if prudent and cost effective. CPC's phone system was replaced in 2013 and meets current CPC communication needs. The UCX telephone system has dramatically improved call tracking ability which will result in more accurate service quality statistics going forward. This reflects CPC's commitment to continual improvement in its processes and practices.

In the 2010 – 2014 surveys, Customers indicated high levels of support for:

- Maintaining and upgrading equipment (83% support)
- Reducing the time needed to restore power (79% support)
- Investing more in the electricity grid to reduce the number of outages (74% support0
- Educating customers about energy conservation (74% support)

The 2017 survey reaffirmed customer perceptions that CPC delivers high reliability services (88% satisfaction).

This indicates strong support for LDC asset renewal programs and based on CPC's existing reliability performance results, changes to program/strategies should be considered if such changes are required to **maintain** existing performance.

CPC will performs customer satisfaction surveys on a biannual basis, starting with the 2017 survey, as per the OEB RRR Filing Guide.

Customer oriented performance - Service Reliability

The reliability indices demonstrate the significant impact of planned outages and outages originating on the 44kV distribution system when compared to the 8.32kV and 4.16kV distribution systems. Many customers are affected by a single 44kVfeeder event as compared to an 8.32kv or 4.16kV feeder outage. Of note is the impact of Loss of Supply on total interruption numbers. This highlights the benefit of continuing the application of distribution automation on the 44kV system to mitigate the impact of outages.

As part of the Smart Grid development CPC has implemented SmartMAP. SmartMAP is an innovative software solution that has improved outage restoration and operational efficiency, decreased system expansion costs, reduced theft of power, energy savings, and improved customer service for CPC. It will result in improved outage documentation and information accuracy.

Outage cause codes and anecdotal information indicate that system renewal, specifically primary underground cable, requires attention in the DSP. Failure to address system renewal needs will affect long term system performance and not address the customer values identified through the customer survey process. Reliability was ranked high in customer surveys. Looking forward DSP investment priorities are expected to result in outcomes that **maintain** or enhance existing reliability performance.

Customer oriented performance - Bill impacts

Bill impact considerations are a key driver of CPC's DSP development. The smoothened investment plan reflected in the DSP contributes to minimized customer bill impacts over the period of the plan and is reasonable (within OEB mitigation guidelines). In the 2017 survey, only 19% of customers indicated that the CPC portion of their electricity bill was unreasonable.

Customer oriented performance - Billing problems

The relatively high performance by CPC staff and systems in billing accuracy precludes the need for specific investment needs in the DSP. The OEB target of 98% accuracy is deemed to be achievable with current systems in place.

Cost Efficiency and Effectiveness – Project/program variance analysis

Projects and programs have been prepared in consideration that spending must be achievable with the resources that are available (i.e. suppliers (material), design services, municipal approvals, contract labour, vehicles, etc.) in a timely manner. Programs are to be completed in the year they are budgeted unless carryover spending has been specifically planned for. Material projects exceeding a designated threshold of +/- 20% will require a detailed variance explanation.

Cost Efficiency and Effectiveness - DSP Spending Progress Report

The DSP has been prepared in consideration that program spending must be achievable with the resources that are available (i.e. suppliers (material), design services, municipal approvals, contract labour, vehicles, etc.) in a timely manner. Programs, especially discretionary ones, are expected to be completed in the period(s) they are budgeted. Annual DSP spending exceeding a designated threshold of +/- 10% will require a detailed variance explanation.

Asset/System Operations Performance – Reg. 22/04

CPC continues to demonstrate prudent compliance with O. Reg. 22/04 and as such ESA compliance continues to play a key role in project prioritization. There are no major changes to existing programs during the period of the DSP.

Asset/System Operations Performance – Substation loading

The substation loading pattern in the CPC's service area indicates that existing facilities have available capacity during the period of the DSP to accommodate expected load growth. This will continue to be monitored especially loading in the Stayner area. Every time a substation transformer is overloaded, even for short term operational purposes, loss of transformer life accumulates. As MS transformers tend to be one of the most expensive investments in the distribution system, prudent management of transformer loading will maximize lifecycle value.

Improving contingency capability between substations would be of value. For the period of the DSP, CPC has adopted a performance target of transformer peak demand <= nameplate rating.

Asset/System Operations Performance – Feeder loading

Existing performance is within planning capacity thresholds and as such there is no specific impact on the DSP. For the period of the DSP, CPC has adopted a performance target of peak feeder load <= 600 Amps.

Asset/System Operations Performance – System Losses

Existing performance is within performance targets and as such there is no specific impact on the DSP other than open point designation on certain feeders. For the period of the DSP, CPC has adopted a performance target of maximum 5% loss.

A summary of performance targets to be referred to throughout the period of the DSP are shown in Table 17 below:

Performance Indicator	**Targets**				
	2018	**2019**	**2020**	**2021**	**2022**
Reliability (SAIFI)	0.62	0.62	0.62	0.62	0.62
Reliability (SAIDI)	0.46	0.46	0.46	0.46	0.46
Customer Care*	-	A	-	A	-
Customer Image*	-	A	-	A	-
Management Operations*	-	A	-	A	-
Customer Centric Engagement Index(CCEI)*	-	85%	-	85%	-
Customer Experience Performance rating (CEPr)*	-	85%	-	85%	-
Billing Accuracy	98%	98%	98%	98%	98%
Billing Impact	Annual rates subject to OEB approval (within mitigation guidelines)				
Material Project variance	<=+/- 20%	<=+/- 20%	<=+/- 20%	<=+/- 20%	<=+/- 20%
DSP progress variance	<=+/- 10%	<=+/- 10%	<=+/- 10%	<=+/- 10%	<=+/- 10%
ESA Reg 22/04	0 NC	0 NC	0 NC	0 NC	0 NC
Substation loading (Normal)	Peak demand <=nameplate	Peak demand <=nameplate	Peak demand <=nameplate	Peak demand <=nameplate	Peak demand <=nameplate
Feeder loading	Feeder peak load <= 600 Amps	Feeder peak load <= 600 Amps	Feeder peak load <= 600 Amps	Feeder peak load <= 600 Amps	Feeder peak load <= 600 Amps
Losses	<5%	<5%	<5%	<5%	<5%

Table 17 – DSP performance targets

*Customer satisfaction surveys performed biennially

Annual performance variances that are not within target ranges or meet minimal performance thresholds would result in senior management review of the cause that may result in changes to immediate or future plans to direct future performance back to target levels.

<u>RRFE Performance Scorecard</u>

The RRFE Performance Scorecard supports the key plan objectives of maintaining current reliability levels and low overall cost to the customer during the forecast period.

Scorecard - COLLUS PowerStream Corp. 9/29/2016

Performance Outcomes	Performance Categories	Measures		2011	2012	2013	2014	2015	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		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		98.20%	98.20%	98.00%	70.90%	73.70%		65.00%	
	Customer Satisfaction	First Contact Resolution					99%	99.68			
		Billing Accuracy					99.94%	99.98%		98.00%	
		Customer Satisfaction Survey Results					A	A			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness						84.00%			
		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]		0.87	0.51	0.10	0.03	2.36			0.46
		Average Number of Times that Power to a Customer is Interrupted [2]		0.71	0.21	0.73	0.63	0.88			0.62
	Asset Management	Distribution System Plan Implementation Progress					In progress	In progress			
	Cost Control	Efficiency Assessment			3	3	3	2			
		Total Cost per Customer [3]		$508	$531	$500	$512	$528			
		Total Cost per Km of Line [3]		$23,544	$24,270	$23,849	$24,260	$24,739			
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]						9.71%			16.86 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time				100.00%	100.00%				
		New Micro-embedded Generation Facilities Connected On Time				100.00%	100.00%	100.00%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.34	1.42	1.25	1.10	1.40			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		0.39	1.49	1.41	1.27	1.41			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	8.01%	8.01%	8.98%	8.98%	8.98%			
			Achieved	2.26%	0.10%	8.40%	11.21%	10.86%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the fixed 5-year (2010 to 2014) average distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the new 2015-2020 Conservation First Framework. This measure is under review and subject to change in the future.

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

Table 18 – RRFE Performance Scorecard

5.3 Asset Management Process

This section of the Distribution System Plan (DSP) provides a high level overview of CPC's asset management process.

CPC's asset management process is a systematic approach used to plan and optimize ongoing capital, operating and maintenance expenditures on the distribution system and general plant. Electricity distributors are capital intensive in nature and prudent capital investments and maintenance plans are essential to ensure the sustainability of the distribution network. CPC is continuing efforts to improve the information available to the asset management process for all major equipment.

5.3.1 Asset Management Process overview

a. Asset Management objectives and relationship to corporate goals

CPC's asset management objectives align with CPC's corporate goals and are implicitly summarized in CPC's Corporate Vision and Mission statements

VISION - WHERE WE WANT TO GO
Together, we will grow, maximize opportunities and exceed customer and shareholder expectations

MISSION—WHO WE ARE
Our business provides people with the energy for success, and with the necessities of life

Figure 5 – CPC Mission and Vision statements

The key outcome is maintaining a professional level of customer service standards at a reasonable cost.

This is achieved through the adherence, in every day actions, to CPC Values which are:

VALUES - HOW WE ACT
We value the entrepreneurial spirit to responsibly and decisively challenge the conventional.
Trust - ***Building & Maintaining Customer Confidence*** ✓ We value a work environment based on public accountability, customer satisfaction, respect and giving back to the community; ✓ When problems arise, they are dealt with quickly, professionally and courteously; ✓ Citizens recognize our community relationship and responsiveness as key values of local ownership; ✓ We operate in an environment of openness and transparency while protecting our customers' confidentiality.
Responsibility - ***Committed to Service Quality, Reliability & Conservation*** ✓ We value prudent and responsible financial management; ✓ We value a high standard of environmental excellence; ✓ We value superior health and safety standards and practices; ✓ We value our obligation to protect our customers and staff by exceeding the highest standards of training for our employees.
Sustainability - ***Environmental, Economic, Social & Cultural*** ✓ We value sustainable community planning; ✓ We value the gold standard of environmental excellence; ✓ We value the four pillars of sustainability; environmental, Economic, Social & Cultural; ✓ We value a sustainable Regional approach.
People - ***Strong Relationships & Pride Make a Difference*** ✓ We value our employees as our most important asset and celebrate their accomplishments; ✓ We listen, and we respond in the best manner we can; ✓ We treat people with dignity, fairness and respect; ✓ We value individual and organizational accountability; ✓ We value timely, effective, honest, and open communication throughout the organization, with our stakeholders.
Partnerships & Collaboration ***- Leveraging & Sharing Resources*** ✓ We value integrated solutions that eliminate duplication and improve efficiency and effectiveness; ✓ We value peer and industry partnerships and the opportunity to improve cost and service levels in our community and the communities we serve.
Continuous Improvement - ***Business Processes & Technology That Delivers Results*** ✓ We embrace the opportunity of legislative & regulatory reform and the need to stay "one step ahead". ✓ We strive to remain at the leading edge of technology.

Figure 6 – CPC Values

CPC's Mission, Vision and Corporate Values form the foundation for CPC's Corporate Objectives which are:

1. To provide safe, high quality electricity services to all our customers.
2. To maintain a sound financial position while striving to meet the financial expectations of the shareholders by communicating business outcomes.
3. To build and strengthen customer relationships.
4. To pursue new entrepreneurial opportunities both locally and regionally which benefit our customers and provide value to the business and our shareholders.
5. To build and maintain a sustainable electricity system based on a strong asset management program.
6. To seek and encourage efficient and effective improvements by supporting integrated business solutions wherever appropriate and practical.
7. To be an "employer of choice" where employees are proud to work and others want to work.
8. To be recognized as a leader in environmental stewardship.
9. To promote conservation and the wise use of electricity resources.
10. To identify and build strong community relations.
11. To encourage and support local economic development.
12. To promote and encourage the advancement of technology and innovation

CPC has identified seven (7) asset management objectives that align with corresponding corporate objectives:

- Construct, maintain and operate all assets in a safe manner;
- Monitor and address asset condition issues in a timely manner to ensure the continued reliable supply of electricity delivery
- Ensure corporate performance and asset management plans align with customer service expectations
- Manage investment planning to mitigate rate impacts while maintaining corporate financial stability and long term sustainable performance.
- Develop and improve the GIS as the prime asset management register
- Ensure that environmental considerations are taken into account in the design and management of the distribution system.
- Achieve the 2015 – 2020 CDM targets allocated to CPC

The Corporate and Asset Management objectives form the high-level philosophy framework for CPC's investment program and are implicitly embedded in CPC's capital investment planning process and maintenance program.

The table below shows the linkages between RRFE Outcomes, Corporate Objectives and Asset Management objectives.

RRFE Outcome – Operational Effectiveness			
Corporate Objectives	Asset Management Objective	AM Objective Measure	AM Objective Target
To provide safe, high quality electricity services to all our customers.	Safety - Construct, maintain and operate all assets in a safe manner	ESA Non-Compliance	"Zero" NC
To build and maintain a sustainable electricity system based on a strong asset management program	Reliability - Monitor and address asset condition issues in a timely manner to ensure the continued reliable supply of electricity delivery	1.SAIDI 2.SAIFI	1.SAIDI within range of past 5 year performance 2.SAIFI within range of past 5 year performance
RRFE Outcome – Customer Focus			
To build and strengthen customer relationships	Customer Service - Ensure corporate performance and asset management plans align with customer service expectations	Customer Survey	Customer survey results => previous survey for: a) Customer Care b) Company Image c) Mgmt Operations
RRFE Outcome – Financial Performance			
To maintain a sound financial position while striving to meet the financial expectations of the municipality by communicating business outcomes to the owner	Financial Integrity - Manage investment planning to mitigate rate impacts while maintaining corporate financial stability and long term sustainable performance	DSP implementation	DSP annual investment category spending +/- 10% of plan
To seek and encourage efficient and effective improvements by supporting integrated business solutions wherever appropriate and practical.	Effective integration - Develop and improve the GIS/SmartMAP as the prime asset management register	Development of GIS/SmartMAP Asset Management capabilities	2020 GIS capabilities > 2015 GIS/SmartMAP capabilities for Asset Management
RRFE Outcome – Public Policy Responsiveness			
To be recognized as a leader in environmental stewardship	Environmental - Ensure that environmental considerations are taken into account in the design and management of the distribution system.	Reportable spills to the MOE	Zero reportable spills to MOE from Code 5 events
To promote conservation and the wise use of electricity resources	Conservation - Achieve the 2015 – 2020 CDM targets allocated to CPC	Energy (GWH) saved through annual CDM programs	16.86 GWh saved by 2020

Table 19 – RRFE Outcomes - Corporate Objectives - Asset Management linkage

For investment benefit and Risk assessment, it is necessary to identify the relative priority of each asset management objective with respect to each other. Different investments will have different benefits and Risks with respect to the asset management objectives and weighting the asset management objectives will aid in identifying those investments that best align with them from an overall benefit and Risk perspective. The seven objectives are each assigned a relative weight of 0 - 1.0 with the total sum of the objectives equalling 1.0.

Safety – This objective has been given the highest priority by CPC. Safety comprises organizational efforts to ensure that worker and public safety is paramount in day to day activities. No other objective is weighted higher than safety. The Safety objective is assigned a weight of 0.25

Reliability – This objective is the second highest priority. Together with safety it is a key corporate objective outcome. In customer surveys, it has ranked high in importance of customer needs. The Reliability objective is assigned a weight of 0.20

Customer Service – This objective ranks relatively high in ensuring that business outcomes meet the value needs of the customer. The Customer objective is assigned a weight of 0.20

Financial integrity - A stable rate of return, low electricity rates and ability to sustainably invest in distribution system access, service, renewal and general plant are key to the long term success of this objective. Balancing of stakeholder interests in this area is an ongoing exercise. In customer surveys, low electricity rates ranked first in importance of customer needs. In consideration that CPC's controllable portion of the customer bill is less than 25%, the Financial integrity objective is assigned a weight of 0.15

Effective integration – This objective ensures that continual improvement of processes and practices ranks high in consideration of program development and deliverables. It is assigned a weight of 0.10.

Environmental – It is recognized that environmental considerations benefit the community as a whole. Considering the low likelihood of CPC to affect the environment (e.g. oil spills, aesthetics, etc.) this goal does not carry the priority of the previous goals. The Environmental objective is assigned a weight of 0.05

CDM achievement –The successful delivery of the CDM program supports public policy objective of electricity conservation. The CDM objective is assigned a weight of 0.05.

Objective	Weight
Safety	0.25
Reliability	0.20
Customer Service	0.20
Financial Integrity	0.15
Effective Integration	0.10
Environmental	0.05
CDM	0.05
Total	1.00

Table 20 – Objective weighting summary

An integral part of achieving the asset management objectives is a maintenance program to ensure system performance is sustained during the entire asset service life. CPC has in place inspection and routine maintenance programs to achieve this.

CPC has adopted an Asset Management policy to ensure a continual and consistent focus on delivering services in a way that balances Risk and long-term costs (Appendix A). The policy establishes the core asset management principles that drive CPC's planning framework.

b. Asset Management process components

CPC's Asset Management planning cycle is shown in Fig. 7 below.

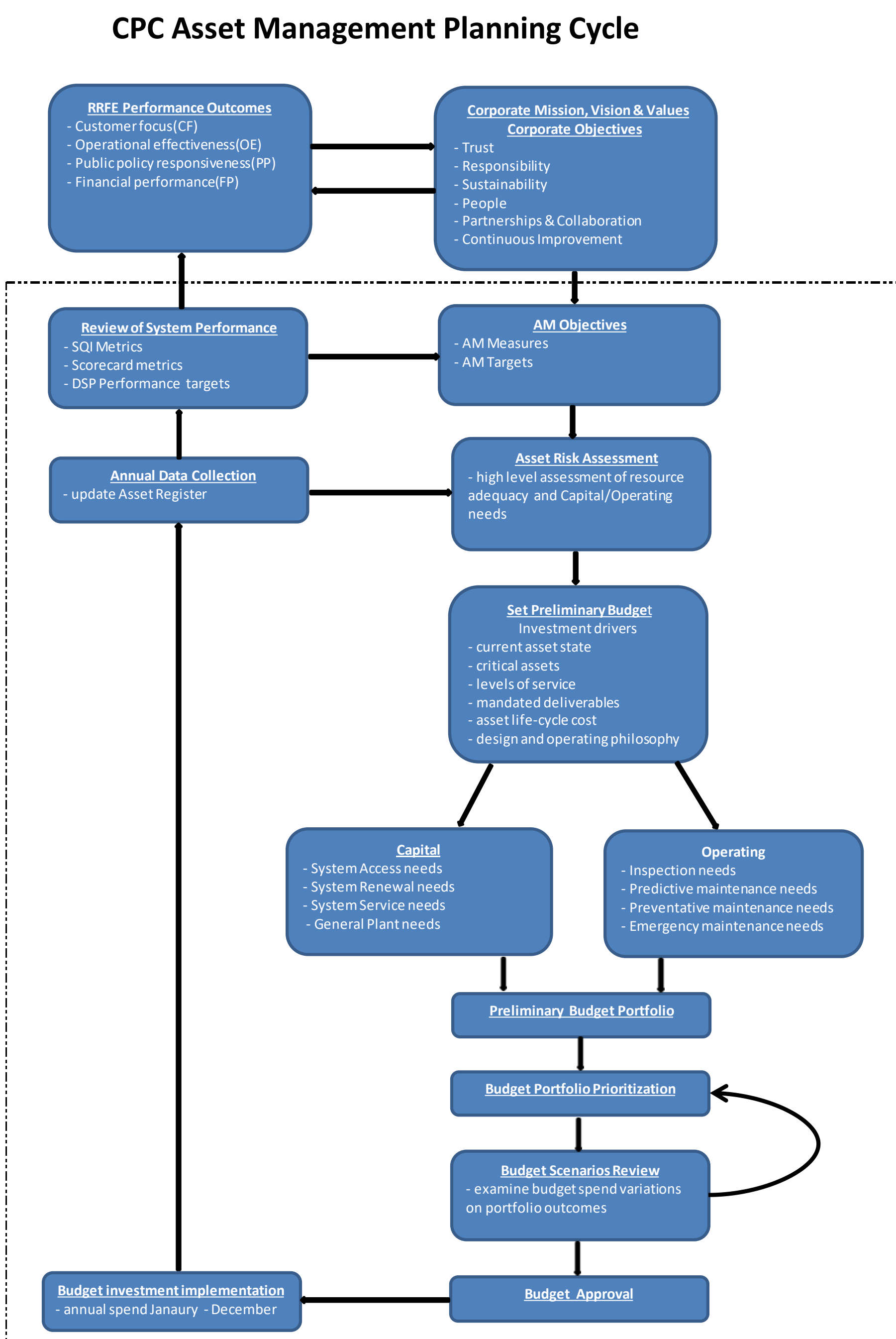

Figure 7 – CPC Asset Management Planning Cycle

The Asset Management planning cycle is a process designed to achieve CPC's Asset Management Objectives. The process is a cyclical one that begins with a review of system performance and whether current performance meets CPC's asset management objectives. Asset performance information and annual asset data collection is used to update CPC's asset register for the investment planning part of the cycle. Performance data normally reflects the previous year's data. Data collection is ongoing as new/replaced assets are added to the system. Asset performance information collected is used to calculate annual OEB SQI and Scorecard performance metrics which tie back to RRFE outcomes. Performance information is also used to determine how well CPC's Asset Management objectives have been achieved in the past investment period.

The asset management process has at its foundation an asset register where asset information is held. For CPC, the asset register is not a single information source but is composed of digital and paper records in separate locations with specific owners. The four key components that comprise the Asset Register are the ESRI Geographical Information System (GIS), the Microsoft Dynamics GP financial management system, the Harris Northstar Customer Information System (CIS) and Operations Records databases/files.

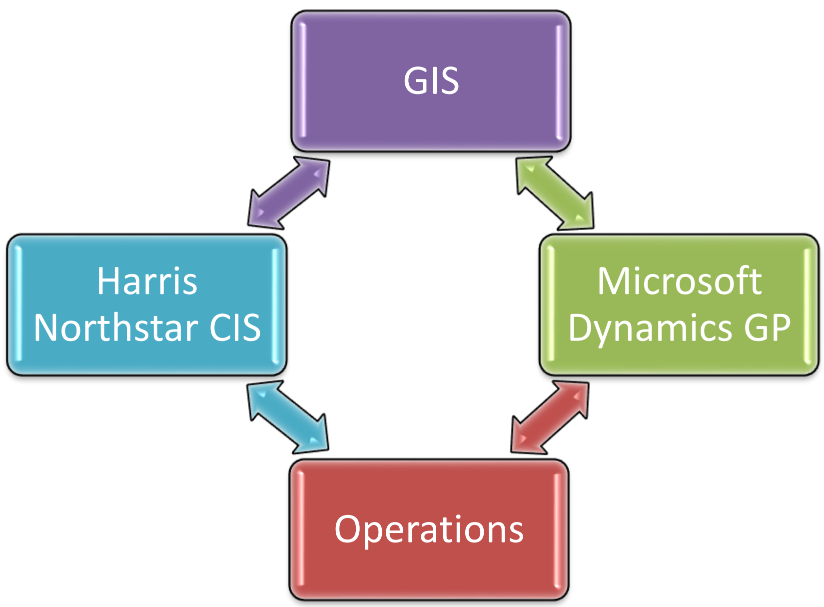

Figure 8 – CPC Asset Register structure

The Harris Northstar CIS platform is hosted by the UCS group, while the Microsoft Dynamics GP platform is owned and maintained by CPC.

The GIS is the primary asset register component for all non-general plant assets. See below for example of potential pole attribute information:

Pole attributes information

- Class
- Material Type
- Species
- Treatment Type
- Height
- Supplier
- Purchase Order number
- Cost
- Date Stamp
- Date Installed
- Work Order Number
- Ownership
- Pole Number
- GRID #
- Framing Type
- Attachments (e.g. joint use, etc.)
- Inspection history dates
- Inspection reports
- Strength test history
- Health Index score
- Maintenance history
- Bar Code designation

As can be seen, there is a significant amount of attribute information that can be collected from even the simplest of field assets. The GIS also holds asset inspection and maintenance information. The CPC GIS is a new system and the long term plan is to have increasing amounts of asset information in the GIS by moving/linking asset information from Operations paper files and dispersed electronic databases to the GIS. General Plant assets (other than land and buildings) are non-geospatial assets and managed separately through the Microsoft Dynamics GP financial management system.

The CPC GIS has evolved since its initial inception in 2007 and provides a high degree of functionality including:

- a Work Order layer that allows for accurate tracking and reporting of all jobs and tasks affecting the distribution system.
- a mobile platform of the GIS (ArcGIS) has been provided to field staff to provide up to date mapping information. Field staff use the mobile GIS platform to view and edit the information pertaining to the distribution system.
- the GIS is also available to PowerStream Control room staff who provide after-hours call centre services.
- an Outage map application that will allow users to view outage information on the CPC website.
- application addition of the Utilismart "SmartMAP" software provides a geographic analysis tool for the distribution system. Smart Map builds an analytic model of the distribution system and combines that with data from smart meters, wholesale meter points and other sensors to create a sophisticated simulation of the current system. Smart Map helps CPC Operations staff understand, plan and operate the system more effectively.

Asset Register			
Asset register component	**Owner/Location**	**Asset information**	**Information media**
ESRI GIS	- Operations	- Asset location (pole GPS coordinates) - Work order history - All attributes (voltage, size, conductor length) -	- digital database composed of multiple map layers of assets
Microsoft Dynamics GP financial management system	- Accounting	- IFRS financial asset value - asset useful life studies - contributed capital	-digital database
	- Accounting	Distribution Plant (bulk GL) - purchase history - depreciation amounts General Plant - purchase history - depreciation amounts (land, buildings, hardware, software, fleet)	-digital database
Harris Northstar CIS	- Customer Service (hosted by UCS Group)	- meter information (physical attributes, consumption, etc.)	digital database; Utilismart database
Operations Records	- Operations	Outage history -SAIFI, SAIDI stats database, trouble reports	digital and paper files
	-Operations	Maintenance Records -transformers, switchgear, poles, stations, meters	digital and paper files
	-Operations	Inspection Records - transformers, switchgear, poles, stations -	digital files
	-Operations	Asset utilization records -station, feeder loading -	digital and paper files Utilismart database(44kV)
	-Operations	Fleet history Tool, test equipment history	digital and paper files

Table 21 - CPC Asset Register

The investment planning part of the asset management process begins with updated asset register information and a high level assessment of resource adequacy and Capital/Operating needs. A preliminary budget for investment is set. The preliminary budget consists of capital and operating funds determined by asset investment drivers, financial/capability considerations and other factors:

- Investment drivers (asset state; sustainable level of service; critical assets; asset lifecycle cost; design, operations and maintenance strategies)
- Financial stability considerations (long term investment financing, depreciation stability, debt/equity ratio, etc.)
- Rate mitigation considerations
- Shareholder return considerations
- Historical spending considerations
- Resource capability considerations
- Regulatory/government directives/policy

CPC's asset management process identifies five key fundamental drivers of asset investment:

1. The current state of the assets
2. Assets critical to performance
3. CPC's desired level of service and mandated deliverables
4. CPC's asset life-cycle cost considerations
5. CPC's design and operating philosophies, and maintenance strategies

The preliminary budget provides the required information on organizational financial capability for ranking, prioritizing and pacing of investment projects that result in the achievement of the four RRFE performance outcomes.

With the preliminary budget as a guide, investment planning then proceeds. Capital Investments are placed in one of the four investment categories:

1. System Access
2. System Renewal
3. System Service
4. General Plant

Operating investments are reflected in the annual asset maintenance plan. The asset maintenance plan reduces unplanned and emergency repairs as it emphasizes preventative and predictive maintenance. It determines which assets are maintained to maximize asset life-cycle benefit and which assets are simply replaced reactively.

A base budget portfolio of capital investments is produced. Investment justification is compiled for projects in the portfolio along with more detailed business cases for the larger material project proposals.

At this stage of the process, discretionary capital investments are scored to provide an initial prioritization ranking based on Risk and benefit considerations. Non-discretionary capital projects are automatically included as per scheduled need. In general, non-discretionary projects are defined as:

- New/modified customer service connections (System Access)
- Road authority required plant relocation projects (System Access)
- Mandated service obligations (System Access)
- Renewable energy projects (System Access)
- Emergency plant replacement (System Renewal - reactive)
- Safety related projects (System Service)

The base budget portfolio is compared to the preliminary budget and prioritized investments are paced/scheduled to optimize system performance, costs and Risks relevant to service delivery. CPC uses a Risk and value scoring mechanism developed internally to classify and prioritize investments. Risk and value assessments provide an initial triage to determine projects that can wait (be deferred to future budget periods) and those that need closer review for potential inclusion in the immediate planning period. Assessments may also indicate that to optimize system performance the preliminary budget may require funding adjustment. Reasons for adjustment consider factors such as:

- Project interdependencies
- Resource (labour, material, etc.) availability
- Cost and benefit uncertainties/Risks
- Capital availability
- Rate impact
- Portfolio effectiveness (corporate goals)
- Portfolio effectiveness (customer value)

In this case revised budget scenarios (high/low) may be considered and the investment portfolio would be re-evaluated to optimize system performance.

Final budget and project selection determined through CPC senior management discussion and review.

Following final investment plan approval, the asset management process would then proceed to the plan implementation stage. Investment plans would be executed and resulting system performance outcomes would be collected and reviewed starting the asset management planning cycle over again.

5.3.2 Overview of Assets Managed

a. Description of the distribution service area

CPC's distribution service territory consists of four distinct geographically separated urban areas which includes the Towns of Collingwood, Stayner and Thornbury and the Village of Creemore. The CPC service area contains mostly urban customers with a diverse local industrial sector. Key industrial sectors include:

- Retail Trade
- Accommodation and food services
- Health Care and Social Assistance
- Construction
- Manufacturing
- Arts, entertainment and recreation

Tourism is a key industry in CPC that offers four-season recreation and leisure pursuits for both residents and visitors alike.

As of December 31, 2015, CPC serves approximately 14,715 residential customers, 1,742 GS<50 customers and 126 GS>50 customers in a combined service area of 45 square kilometers.

CPC is located on the shores of Georgian Bay in West Simcoe County. The service area is not contiguous with Thornbury, Stayner and Creemore being geographically separate from the Town of Collingwood. The service areas of CPC are all within a short drive from each other.

The CPC service area has warm and sometimes hot summers with cold, longer winters (Köppen climate classification Dfb). Along the shores of Georgian Bay, frequent heavy lake-effect snow squalls increase seasonal snowfall totals upwards of 3 m (120 in).

Severe weather in the summer manifests itself mostly in the form of thunderstorms that can damage overhead distribution plant. In the winter, severe weather may consist of snow squalls, high winds and the occasional episode of freezing rain.

CPC is responsible for maintaining distribution and infrastructure assets deployed, including 219 kilometers of overhead lines and 135 kilometers of underground lines.

CPC's customer growth since 2013 has been low. From 2013 to 2015 the average annual growth rate was 1.0%.

CPC is embedded off Hydro One's Stayner TS and Meaford TS. CPC is a registered Market Participant dealing directly with the IESO and has eight metering points metered by Hydro One. Consequently, CPC deals with both the IESO and with Hydro One for the purchase of electricity which is passed through to its customers. As an embedded utility, CPC is billed monthly by Hydro One for Transmission and Low Voltage Charges.

CPC does not act as a host distributor to any utilities.

CPC's service area is bordered by the following utilities:

• Hydro One

• Wasaga Distribution Inc.

Map of the CPC service area is shown below.

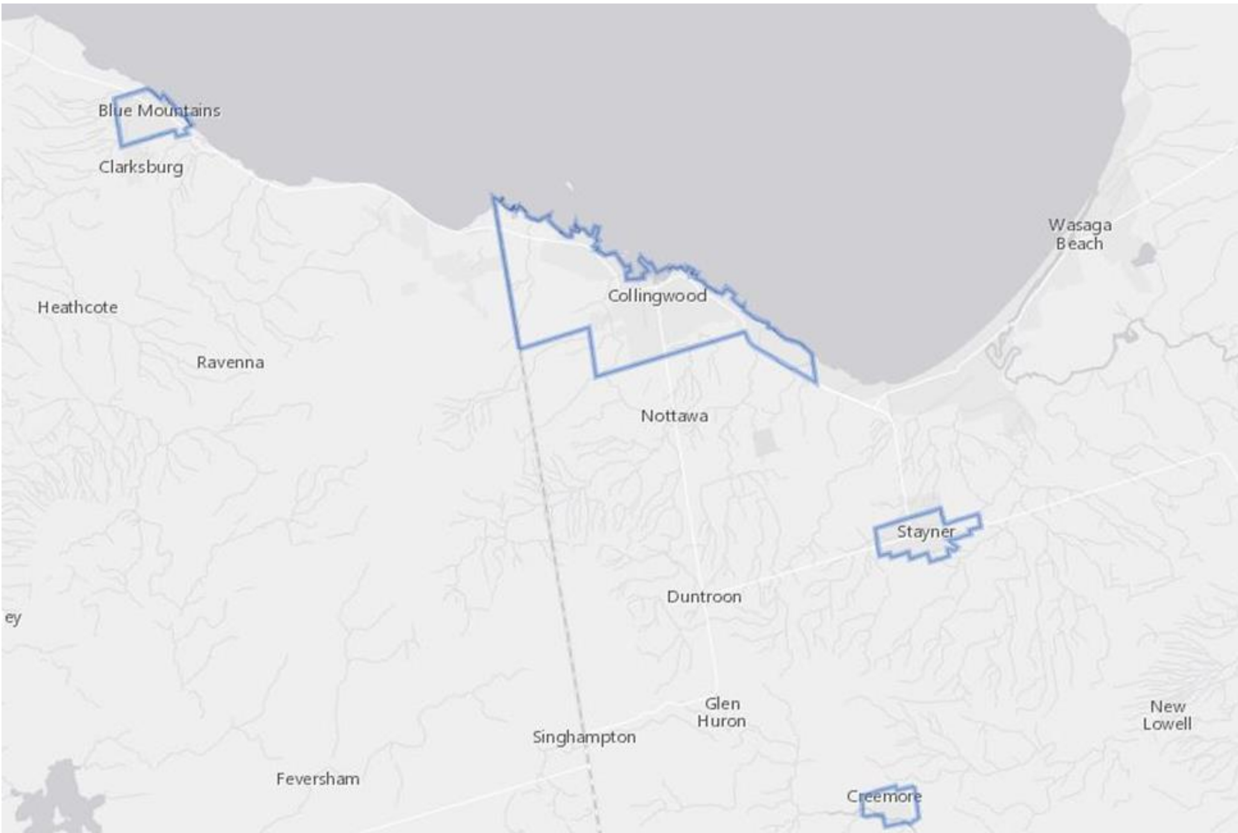

Figure 9 – CPC Service Territory

b. System configuration

The CPC service area receives deliveries of bulk power through 44kV feeders emanating from the HONI owned Stayner TS and Meaford TS.

Collingwood's wholesale electric supply comes from three 44kV sub-transmission feeders (M3, M7, M8) originating at Stayner TS. These feeders are dedicated to CPC supply. There is also one shared 8.32kV feeder (F1) originating at Hydro One owned Brocks Beach DS. This feeds parts of Highway 26 in the east end of Collingwood.

Stayner's wholesale electric supply comes from two 44kV sub-transmission feeders (M2, M5) originating at Stayner TS. The M2 supplies Stayner MS#2 and the M5 supplies Stayner MS#1.

Thornbury's wholesale electric supply is a radial 44kV sub-transmission feeder (M2) originating at Meaford TS.

Creemore's wholesale electric supply comes from one 8.32kV express feeders (F1) from Hydro One owned Creemore DS. A second feeder is expected to become available early in 2017. The upstream supply to Creemore DS is the M2 feeder from Stayner TS.

The 44kV feeder system is owned and operated by HONI outside the municipal boundaries. CPC owns and operates the portions of the 44kV feeders inside CPC service territory. There are 8 IESO Registered Wholesale Metering points at the service area borders. Communications with the PMEs is through cellular VPN through PUI/Rogers network. Metering point information is provided in Table 22 below:

IESO ID# **Main Meter** Alternate Meter	**Meter Seal Expiry**	**Name**	**Circuit ID**	**Voltage**	**Metering Installation Type**	**Built**
1000006500	**2018**	Thornbury PME	Meaford M2	44kV	Primary	2004
1000006501	2024	"	"			
1000010440	**2017**	Creemore DS F2 PME	H1 Creemore DS F2	8.32 kV	Primary	2005
1000010441	2024	"	"			
1000008670	**2019**	Collingwood South PME	Stayner TS M3	44kV	Primary	1992
1000008671	2024	"	"			
1000006080	**2018**	Collingwood West PME	Stayner M7	44kV	Primary	2004
1000006081	2024	"	"			
1000006100	**2019**	Collingwood East PME	Stayner M8	44kV	Primary	1997
1000006101	2024	"	"			
1000006090	**2019**	Wasaga Beach PME3	H1 Brocks Beach DS F1	8.32 kV	Primary	1996
1000006091	2025	"	"			
1000016630	**2017**	Stayner MS1	Stayner M5	4.16 kV	Secondary	1976/ 2006
1000016631	2018	"	"			
1000009890	**2017**	Stayner MS2	Stayner M2	4.16 kV	Secondary	1988
1000009891	2018	"	"			

Table 22 – IESO Registered Wholesale Primary Metering Points

While there are a number of large users (>500kVA service capacity) that take power directly from the 44kV feeders through customer owned substations, the majority of customers are served from CPC's distribution substations. One user is an IESO registered market participant. There are 14 municipal substations in CPC service territory.

MS Name	**Year**	**Details**	**Transformer Sizes**	**Feeders**
Collingwood MS1	1972	Primary 44kV; Secondary 4.16kV	6/6.7 MVA	5
Collingwood MS2	1978/2008(T)	Primary 44kV; Secondary 4.16kV	8 MVA	5
Collingwood MS3	1966	Primary 44kV; Secondary 4.16kV	3/3.4 MVA	3
Collingwood MS4	1967	Primary 44kV; Secondary 4.16kV	5/5.6 MVA	4
Collingwood MS5	2007	Primary 44kV; Secondary 4.16kV	10 MVA	6
Collingwood MS6	1985	Primary 44kV; Secondary 4.16kV	6/6.7 MVA	5
Collingwood MS7	1989	Primary 44kV; Secondary 4.16kV	5 MVA	5
Collingwood MS8	2007	Primary 44kV; Secondary 4.16kV	4 MVA	4
Collingwood MS9	2010	Primary 44kV; Secondary 4.16kV	10.67 MVA	5
Collingwood MS10	2008	Primary 44kV; Secondary 4.16kV	6 MVA	3
Stayner MS1	1973	Primary 44kV; Secondary 4.16kV	5 MVA	3
Stayner MS2	1986	Primary 44kV; Secondary 4.16kV	5 MVA	3
Thornbury MS1	1976	Primary 44kV; Secondary 8.32kV	6 MVA	3
Thornbury MS2	1986	Primary 44kV; Secondary 8.32kV	5 MVA	3

Table 23 – CPC MS summary

Municipal station locations are shown in Figures 9, 10, 11 and 12 below:

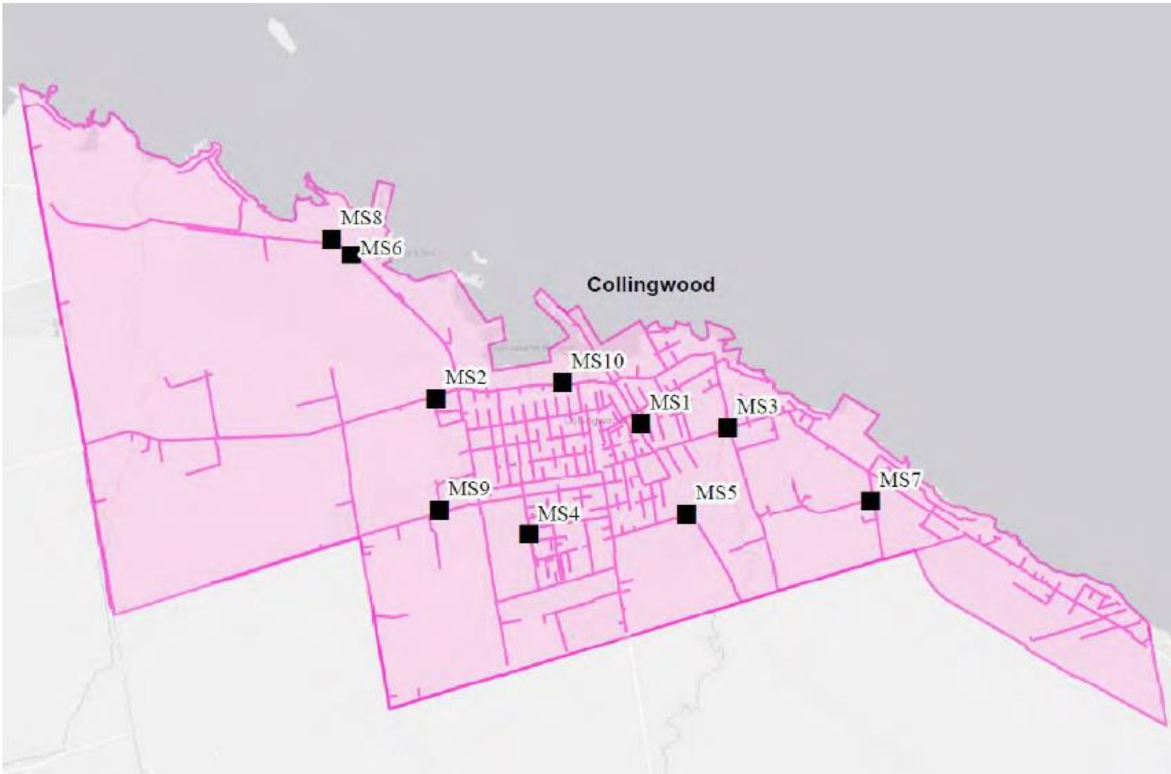

Figure 10 – Collingwood MS locations

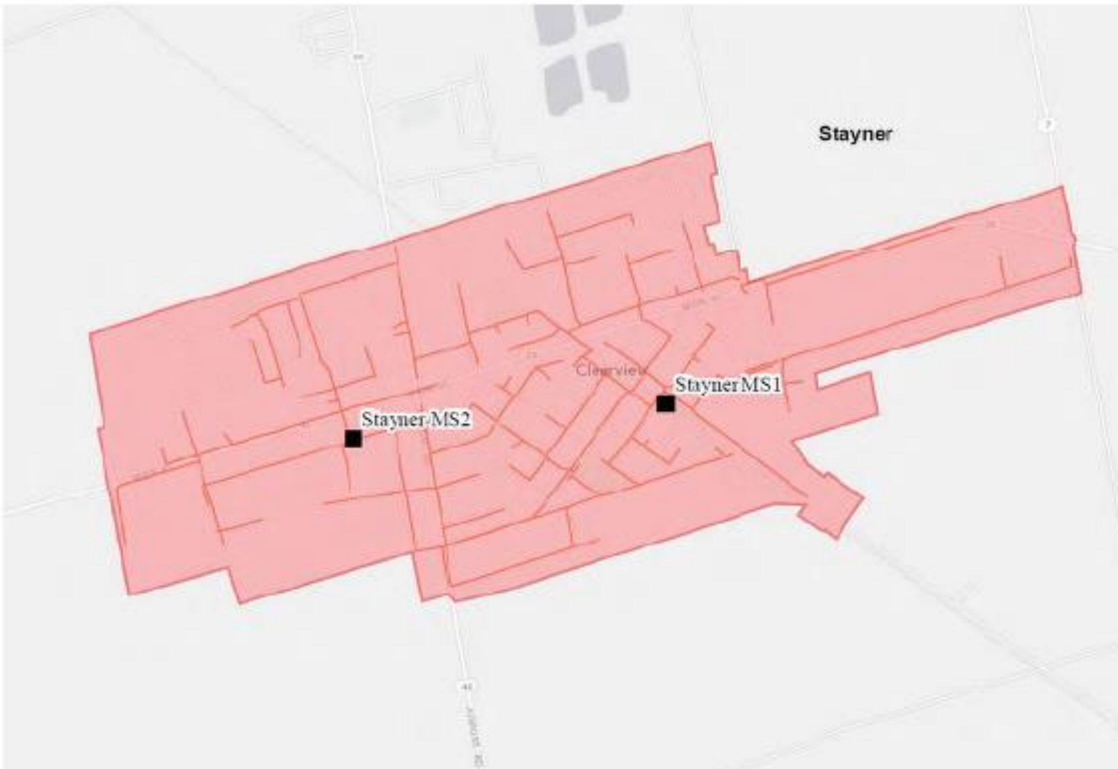

Figure 11 – Stayner MS locations

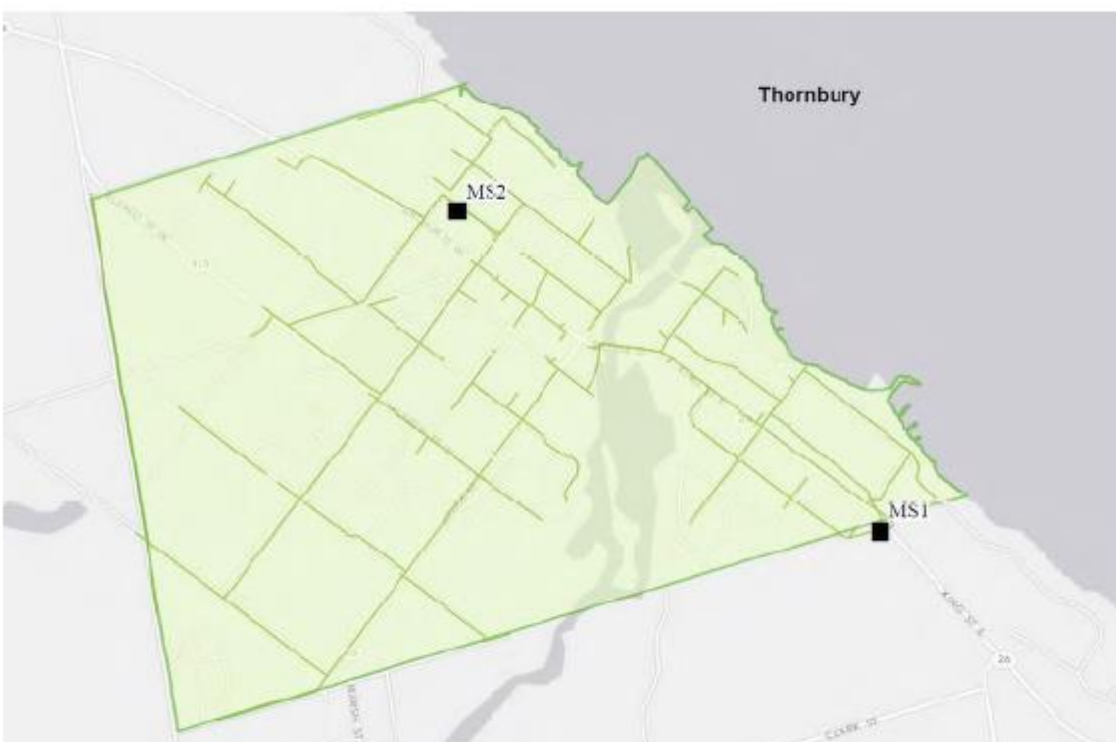

Figure 12 – Thornbury MS locations

Figure 13 – Creemore DS location (HONI)

In the Collingwood and Stayner areas, a network of 4.16kV feeders is used to move the power to residential and small commercial neighbourhoods where it is again transformed down, through local overhead, padmount and vault transformation facilities to user utilization levels of 600/347V, 120/208V and 120/240V. The Thornbury and Creemore areas are serviced by 8.32kV distribution feeders. As of the end of 2015, there are approximately 145km of overhead and 123km of underground 4.16kV circuitry and a total of 35km of overhead and 12km of underground 8.32kV circuitry. There also are a total of 36km of 44kV circuitry owned by CPC. A significant amount of the underground 4.16kV circuitry is single phase distribution within residential subdivisions.

There are no submersible transformer installations, cable chambers, room vaults or other confined spaces in the distribution system.

Distribution feeder maps for the respective service communities are shown below:

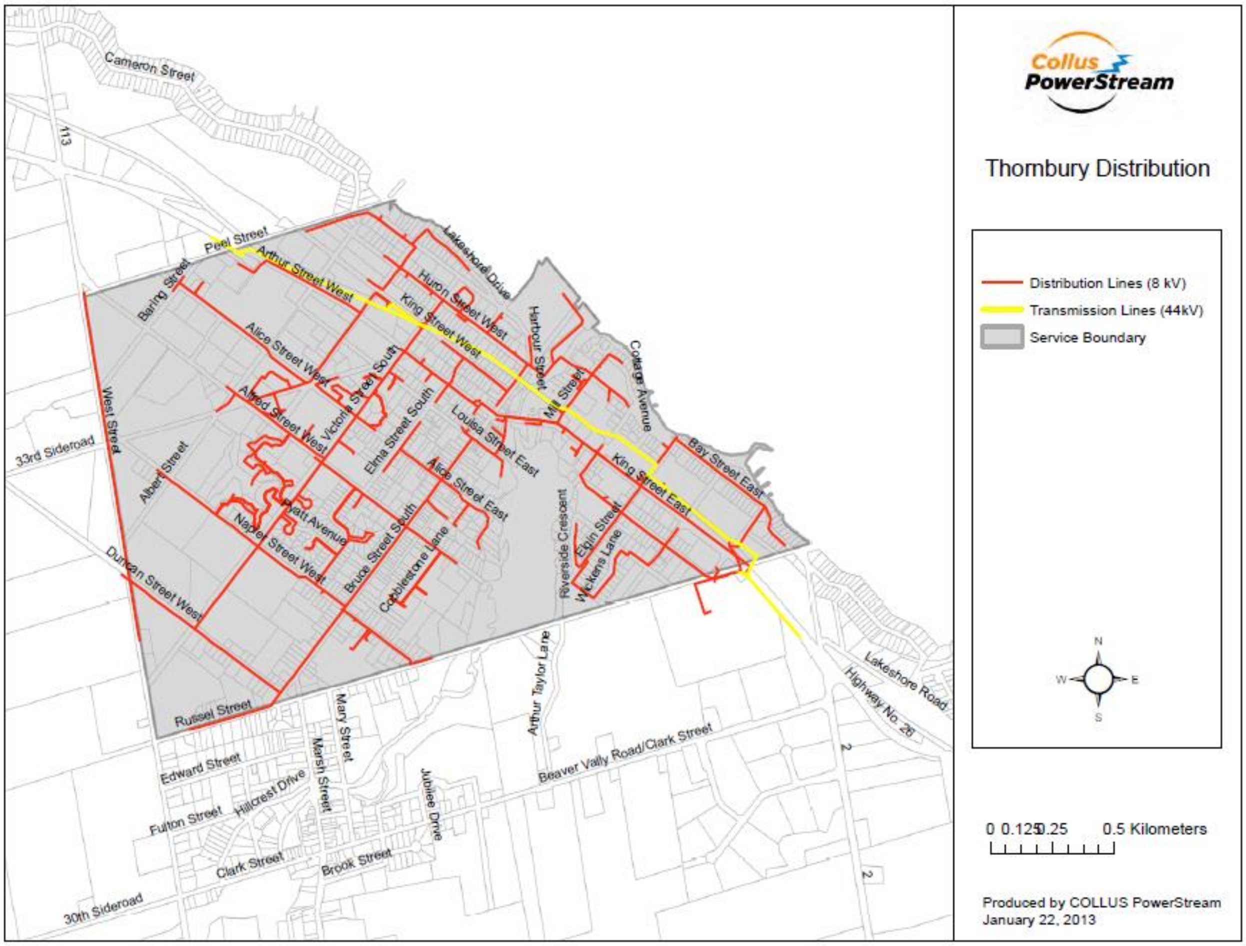

Figure 14 – Thornbury Distribution - Feeder System

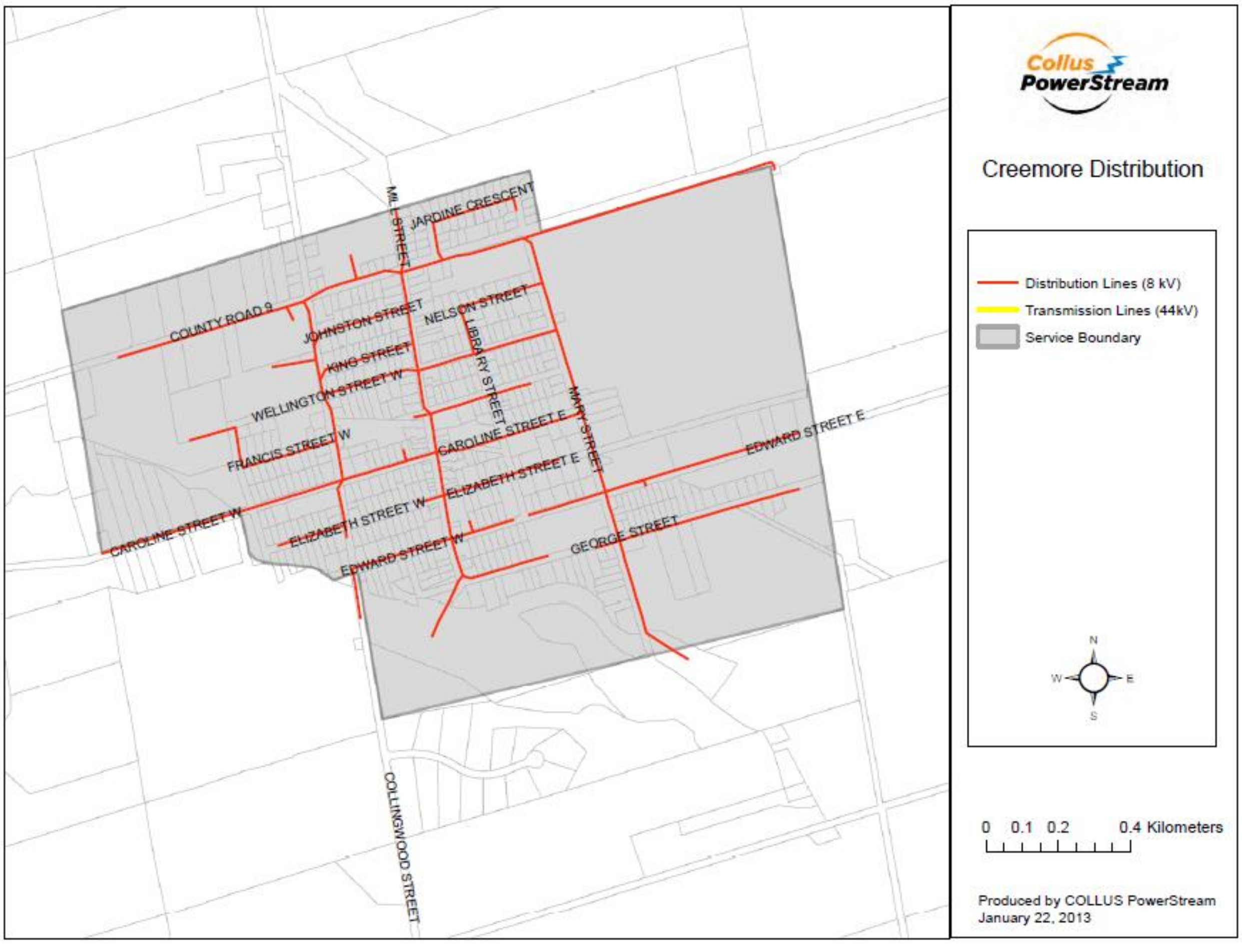

Figure 15 – Creemore Distribution - Feeder System

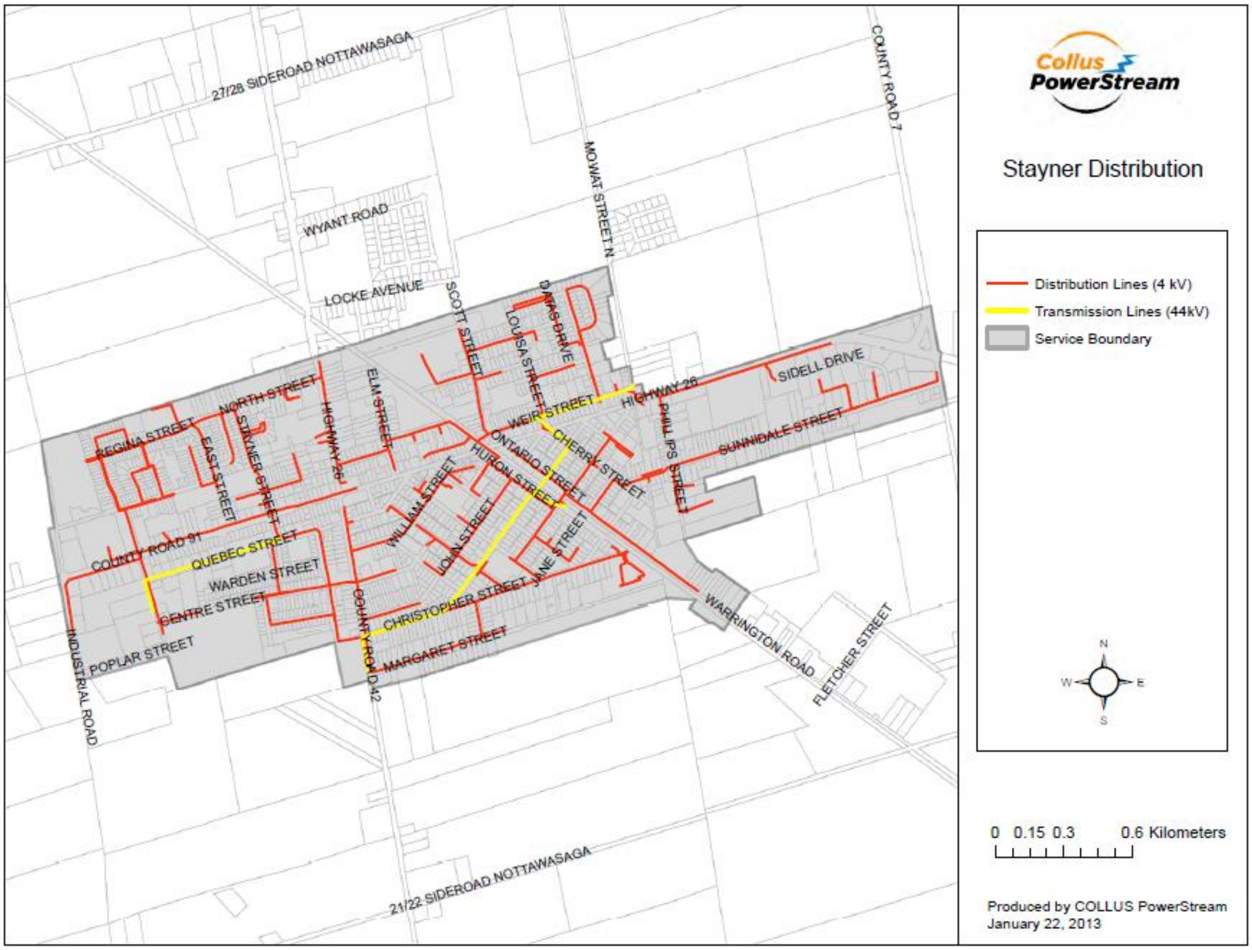

Figure 16 – Stayner Distribution - Feeder System

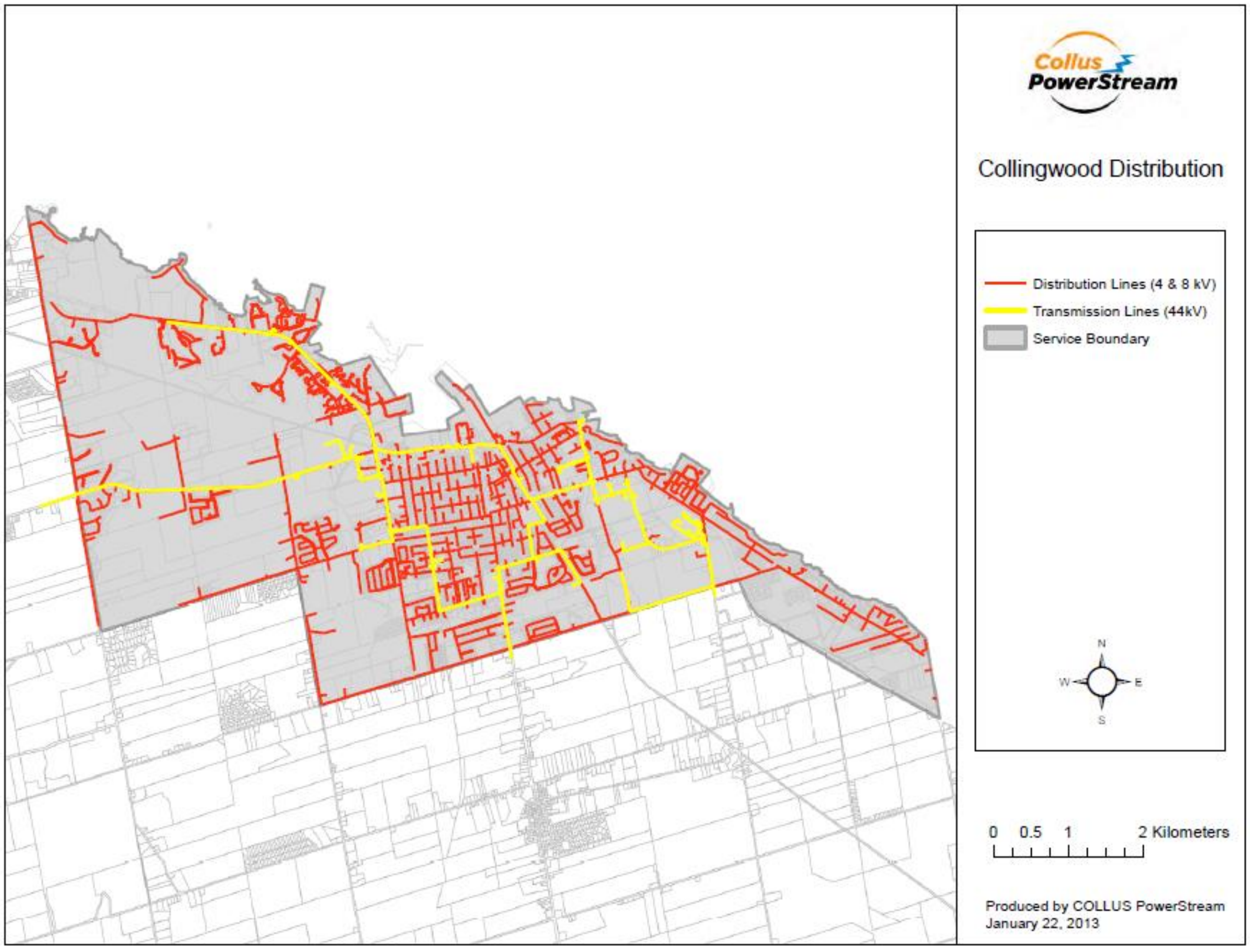

Figure 17 – Collingwood Distribution - Feeder System

c. Information by asset type

Information regarding CPC's key assets by asset type, quantity/years in service and condition is shown in the table below:

Asset	Sub-Category	Quantity[2]	TUL[1] (years)	Asset Life Remaining (TUL base)					Average Age (years)
				<10%	11%-35%	36-65%	66%-89%	>90%	
				Replace	Poor	Fair	Good	Very Good	
Substation Transformers		14	45	4	4	1	5	0	27
Circuit Breakers		36	45	12	9	0	9	6	26
PME		16	40	1	2	6	7	0	19
Meters[3]		16700	15	0	0	12100	3002	1604	5
Pole Mounted Transformers[4]		1016	40	0	0	1016	0	0	N/A
Poletrans[4]		21	N/A	21	0	0	0	0	N/A
Pad Mounted Transformers[4]		1134	40	0	0	1134	0	0	N/A
Pad Mounted Switchgear[4]		35	30	0	0	35	0	0	N/A
Overhead switches (44kV) [4]		80	45	0	0	80	0	0	N/A
Overhead switches (4/8kV cutouts) [4]		1299	45	0	0	1299	0	0	N/A
Poles[4]	Wood Poles	5016	45	614	734	1037	600	1800	N/A
Overhead Conductor [2,5]		216	N/A	0	0	0	100	116	N/A
Underground Cable [2,5]	5kV XLPE cable	3 km	25	3	0	0	0	0	N/A
	15kV Jacketed TRXLPE	132 km	30	0	0	0	80	52	N/A

Note 1 - Typical Useful Life derived from Kinectrics "Asset Depreciation Study for the Ontario Energy Board", July 8, 2010
Note 2 - December 2015 data
Note 3 - November 2016 data
Note 4 - Assets assumed in mid-life condition based on inspection/patrol exception reporting
Note 5 - Assets assumed in early – life condition based on inspection/patrol exception reporting

The data is as of December 2015 except as noted.

Table 24 - Asset Information

Asset condition information varies with the criticality of the asset. Critical station equipment (i.e. power transformers and circuit breakers) are inspected, tested and maintained regularly and generally have more information such as installation date, etc. Tests would readily indicate if the TUL of the equipment is overstated. Equipment installation data is used with the TUL to assess the remaining useful life of the station assets.

Poles are periodically tested. Testing using the Resistograph method began in 2015. This non-destructive test method will provide enhanced condition information going forward. TUL remaining assessments based on inspection results.

Transformers and switchgear have no age information and as such have been assessed in their groups at mid-life condition based on exception reporting from patrols and inspections. Exception reporting would identify individual transformer or switchgear in conditions that would lead to end-of-life determination and near term actions to replace those units would be put in place.

Non-key distribution assets (low unit cost) or those that require no maintenance in themselves (i.e. overhead wire) are not specifically tracked for individual condition assessment. Other assets had too little information to be classified (i.e. overhead switches) but will be included in future condition assessments once data is collected. In general, determination of issues of immediate or future asset performance concern is augmented by CPC staff expert knowledge and distribution system awareness.

Asset categories where significant portions of the population were in poor or replace condition were substation transformers, substation circuit breakers, pole trans, 5kV UG primary cable and wood poles.

CPC has standardized on 336 ACSR for overhead 8.32kV and 4.16kV circuits. The 336 ACSR conductor has well in excess of 500 Amps current carrying capacity.

All 5kV underground primary cable is considered to be in replacement condition and at end of life (<35% life remaining). Programs are in place to replace this cable (3km remaining), at specified locations, with 15kV rated cable of 1/0 size.

Over 1300 wood poles are considered to be in poor or replace condition.

Proactive replacement strategies have been adopted for these key asset types. Other asset types (i.e. substation transformers) are being closely monitored to determine the specific replacement/refurbishment period. At this time no station replacement/refurbishments are planned during the 2018 – 2022 period. Reactive replacement strategies have been adopted for the remainder.

A multiyear long term optimized replacement plan (rate and resource mitigation) for the key end of life pole assets has been prepared.

d. Assessment of existing system capacity

CPC is a winter peaking utility. Winters in CPC's service area are year over year consistent and generally cold, which influences the use of electricity for space heating. Summers are generally hot and humid influencing the use of electricity for space cooling. Canada overall has been warmer than normal for 19 consecutive years and 2015 was Canada's 11th warmest year on record. Although the summers have been getting warmer over the years (resulting in more Cooling Degree Days (CDD)) the summer demand peak is still less than the winter demand peak.

Station Capacity

Station capacity for planning purposes is based on 75% of the normal rating of the station transformers. Short time fluctuations in demand load would not be expected to exceed the normal rating of the station transformer. When normal loading exceeds 75% of the transformer rating the excess amount would be permanently transferred to another station with capacity or if this is not possible, due to system constraints or other issues, new facilities would be planned to be constructed.

In the Collingwood service area, the 75% loading guide allows MS to back each other up to various degrees to handle short term system disturbances and maintenance needs. Limitations in feeder interconnectivity may result in some loading over transformer normal rating for short periods of time.

In the Stayner and Thornbury service areas there are two stations in each which allows for switching between stations/feeders for operational and maintenance. Load growth in Stayner is not expected to exceed the combined planned loading and operating guidelines of the existing stations within the period of the DSP. Should this not be the case, then new facilities will be planned for.

In the Creemore service area there is no CPC owned station. HONI's Creemore DS is being reconstructed to provide for load growth. Completion is expected sometime in 2017 and a new second feeder will be available to service additional load growth in Creemore.

The chart below indicates an average utilization rate of 48% for MS capacity based on 2016 peak demand numbers.

MS Name	Capacity (MVA)	2016 Peak Load (MVA)	Avg % Utilization
Collingwood MS1	6/6.7	4.6	77
Collingwood MS2	8	4.7	59
Collingwood MS3	3 /3.4	2.0	67
Collingwood MS4	5/5.6	3.7	74
Collingwood MS5	10	3.7	37
Collingwood MS6	6/6.7	3.9	65
Collingwood MS7	5	2.6	52
Collingwood MS8	4	1.1	28
Collingwood MS9	10.67	4.0	37
Collingwood MS10	6	1.5	25
Stayner MS1	5	2.4	48
Stayner MS2	5	2.1	42
Thornbury MS1	6	2.5	42
Thornbury MS2	5	1.6	32
Total	84.67	40.4	48

Table 25 – CPC 2016 MS Utilization

CPC has a spare MS transformer (Primary 44kV; Secondary 4.16kV 3 MVA) that can be used for emergency replacement of any of the CPC MS transformers that supply the 4.16kV distribution system. A spare transformer with 8.32kV secondary is available from the CHEC group in the event of a need on the 8.32kV distribution system.

44kV feeder capacity

CPC is embedded within HONI's 44kV distribution system. Recent regional planning consultations have determined that there are no loading constraints at the 44kv feeder level. CPC has standardized on 556 ACSR for overhead 44kV circuits.

8V and 4kV feeder capacity

The 8kV and 4kV feeders, except for the 8kV HONI feeders supplying Creemore, emanate from CPC distribution stations. The feeder loading statistics are from February – April 2016. CPC is winter peaking. The feeder loading stats are non-coincident and are shown in the following chart:

Feeder	Planning Capacity (Amps)	Feeder Capacity (Amps)	2016 Peak Load (Amps)	% Planning Utilization
Collingwood MS1	625			
F1	125	500	115	92%
F2	125	500	79	63%
F3	125	500	163	130%
F4	125	500	153	122%
F5	125	500	129	103%
Collingwood MS2	833			
F1	167	500	149	89%
F2	167	500	71	43%
F3	167	500	205	123%
F4	167	500	80	48%
F5	167	500	146	87%
Collingwood MS3	312			
F1	104	360	64	62%
F2	104	360	70	67%
F3	104	360	138	133%
Collingwood MS4	520			
F1	130	360	97	75%
F2	130	500	198	152%
F3	130	360	32	25%
F4	130	400	187	144%
Collingwood MS5	1040			
F1	260	400	81	31%
F2	260	200	5	2%
F3	260	500	339	130%
F4	260	400	85	33%
F5	0	400	0	0%
F6	0	400	0	0%
Collingwood MS6	625			
F1	125	500	160	128%
F2	125	500	203	162%
F3	125	500	42	34%
F4	125	500	58	46%
F5	125	500	75	60%
Collingwood MS7	520			
F1	130	400	0	0%

F2	130	400	149	115%
F3	130	400	179	138%
F4	130	400	0	0%
F5	185	400	34	18%
Collingwood MS8	416			
F1	104	400	54	52%
F2	104	400	16	15%
F3	104	400	41	39%
F4	104	400	45	43%
Collingwood MS9	1110			
F1	0	500	0	0%
F2	278	500	242	87%
F3	278	500	282	101%
F4	278	500	2	1%
F5	278	500	31	11%
Collingwood MS10	625			
F1	313	500	20	6%
F2	313	500	186	59%
F3	0	500	0	0%
Stayner MS1	520			
F1	130	400	55	42%
F2	130	400	63	48%
F3	130	400	121	93%
Stayner MS2	520			
F1	130	400	59	45%
F2	130	400	135	104%
F3	130	400	7	5%
Thornbury MS1	312			
F1	104	400	87	84%
F2	104	400	19	18%
F5	104	400	68	65%
Thornbury MS2	278			
F1	87	400	17	20%
F2	87	400	46	53%
F3	87	400	46	53%
Creemore DS (HONI)				
F1	280	400	126	45%

Table 26 – CPC 8kV and 4kVFeeder Utilization

Default feeder planning capacity limited to rating of MS transformer capacity. Capacity equally allocated to feeders based on quantity in service to ensure cumulative feeder loading does not overload MS transformer. This assumes a homogenous balanced system. In actual practice, feeder peak loads in excess of planning capacity are balanced by other feeder peak loads under planning capacity so that in the end, the MS transformer capacity is not overloaded. Feeder positions not in service are indicated as having “0” planning capacity.

Feeder loading is generally within planning guidelines and as such is not a key driver of material investments according to System Service needs. Loading in excess of planning guidelines to be reviewed through grid optimization studies.

5.3.3 Asset Lifecycle Optimization Policies and Practices

This section of the Distribution System Plan (DSP) provides a high level overview of CPC's asset lifecycle optimization policies and practices.

a. Formal policies and practices

CPC's policies and practices towards asset lifecycle optimization are derived from CPC's Asset Management Policy and Asset Management Objectives. In managing its distribution system assets, CPC's main objective can be summarized as to optimize performance of assets at a reasonable cost with due regard for system reliability, public & worker safety and customer service expectations.

Key asset lifecycle practices are:

Asset Register development - CPC's GIS is the designated asset register for Field Assets. The asset register is intended to hold/link to asset attribute information as well as linkages to historical financial and non-financial information over each asset's lifecycle. At the current time the GIS holds locational data, inspections data and maintenance data. It is the intent of CPC to populate, over time, the GIS with additional attribute data and linkages to non-operational information (i.e. financial, procurement, etc.).

General plant asset information resides with the respective owners of the asset (i.e. fleet assets reside with the Manager Hydro Services). The asset register will provide the relevant information for ongoing development and optimization of assets inspection, maintenance, refurbishment and replacement programs, assist with asset planning, assist in meeting regulatory/legislative compliance and IFRS accounting standards. The asset register will aid in cost control through optimization of the asset's lifecycle.

For example, subdivision cable is generally installed from a common lot of cable and if cable tests and reliability performance indicate end of life for particular cable sections, it is likely that the other cable sections may be in similar condition thereby warranting a full subdivision cable replacement program versus the "whack-a-mole" approach of repairing fault after fault after fault. The asset register (GIS) can identify common asset attributes and historical performance to develop an appropriate scope for the cable replacement program.

Asset Inspection and Maintenance – CPC follows criteria stated in the Distribution System Code, Regulation 22/04 and ESA guidelines in the development and implementation of its asset inspection and maintenance practices that meet its Asset Management Objectives. CPC maintains the efficiency and reliability of its distribution system through an active inspection, maintenance and asset management program that focuses on customer service, employee safety and cost-effective maintenance, refurbishment and replacement of assets that can no longer meet acceptable utility performance standards. CPC's maintenance strategy is, to the extent possible, to minimize reactive and emergency-type work through an effective planned maintenance program, including predictive and preventative actions.

Predictive maintenance activities involve the testing of elements of the distribution system. These activities include infrared thermography testing, transformer oil analysis, planned visual inspections and pole testing.

Preventative maintenance activities include inspection, servicing and repair of network components. This includes overhead and pad-mounted switch maintenance. Also included are regular inspection and repair of substation components and ancillary equipment.

Emergency maintenance includes unexpected system repairs to the electrical system that must be addressed immediately. This includes equipment failure repair, storm damage repair, emergency tree trimming and other unplanned repair activities. Some emergency maintenance can be considered reactive maintenance for low cost non-critical assets, not under predictive or preventative maintenance, that when they break down, they can be replaced readily (spares available) and pose no safety Risk.

Predictive and preventative maintenance activities are identified through various methods and sources, primarily through feedback from distribution system operations, manufacturer's maintenance recommendations, and annual asset Inspections. Predictive and preventative maintenance is performed to ensure equipment continues to provide its essential functionality in a safe manner over its lifecycle. Some assets require very frequent maintenance efforts (e.g. fleet vehicles), others require infrequent maintenance efforts (e.g. pole structures) and some are essentially maintenance free (e.g. overhead conductor). For most assets, uniform maintenance programs have been set up for the whole class. For very large and critical assets (e.g. station transformers) maintenance programs can be unit specific depending on the nature of asset issues discovered. For example, oil tests on station transformers are very detailed and performed annually to provide the most up to date health assessment of the units:

Oil Sample tests
Dielectric breakdown voltage: ASTM D 877 and/or ASTM D 1816
Acid neutralization number: ANSI/ASTM D 974
Specific gravity: ANSI/ASTM D 1298
Interfacial tension: ANSI/ASTM D 971 or ANSI/ASTM D 2285
Color: ANSI/ASTM D 1500
Visual Condition: ASTM D 1524
Water in insulating liquids: ASTM D 1533
Power-factor or dissipation-factor in accordance with ASTM D 924
Dissolved-gas in oil analysis in accordance with ASTM D3612
Metals & Furans

Table 27 – Oil tests for MS power transformers

CPC has a combined inspection and maintenance practice for field assets. General patrol requirements, as outlined in the Distribution System Code, are adhered to. Asset inspection and maintenance is designed to optimize the asset lifecycle until such time that the asset has reached a condition requiring refurbishment or replacement. Inspection and maintenance program details are provided below:

Program	Field Asset	Practice	Schedule
Distribution Lines			
	44kV Loadbreak switch	Visual Inspection & mtce	Yearly
	44kV Insulator	Washing	As required
	44kV Feeder circuit	Visual, Infrared inspection	Visual every 3 years I/R biannually
	8.32/4.16kV loadbreak switch	Visual inspection	Every 3 years
	8.32/4.16kV Insulator	Washing	As required
	8.32/4.16kV Feeder circuit	Visual, Infrared inspection	Visual every 3 years; I/R biannually
	8.32/4.16kV Cutouts	Visual inspection	Every 3 years
	8.32/4.16kV Padmount Switchgear	Visual inspection	Every 3 years
	8.32/4.168kV Padmount Transformers	Visual inspection	Every 3 years
	Poles	Resistograph test for poles > 5 years old	Biannually
	Overhead lines	Patrol	Every 3 years
	Overhead lines	Tree trimming	3 year rotation
	Meters	Reverification	Measurement Canada guidelines
Stations			
	Station sites, RTU	Inspection	Annually
	Station transformers	Oil tests	Annually
	Station equipment (arrestors, circuit breakers, relays, RTUs)	Maintenance and testing	Every 3 years
	Station equipment	Infrared inspection	As required
General Plant			
	Fleet vehicles(large)	Hydraulic Inspection	Quarterly
	Fleet vehicles	LOF	Every 3 – 4 months
	Fleet vehicles	Rustproofing	Annual only for pickups

Table 28 – Inspection and Maintenance Program

At a minimum, most assets undergo regular visual inspection unless it is not feasible to do so (i.e. direct buried cable).

A summary report of annual Distribution System Maintenance activities is prepared. Maintenance activities are reviewed quarterly by CPC Senior Management to ensure programs are on track.

Asset Refurbishment /Replacement - CPC considers a wide range of factors when deciding whether to refurbish or replace a distribution asset, including public and employee safety, service quality, rate impacts, maintenance costs, fault frequency, asset condition, and life expectancy so that investment in replacement plant is a prudent one. Plant is replaced at the end of life when all refurbishment options have been exhausted.

When an asset has reached end of life and the cost of maintenance and/or the frequency of service disruptions have reached an unacceptable or uneconomic level, the asset is identified for refurbishment or replacement. If the malfunction of these identified assets would create a significant safety, reliability or service impact, the assets are replaced within the current year’s budget. Assets that have not reached their end of life are left in service and refurbished as required based on service reliability, condition assessment and regular inspections as required under the Distribution System Code. Fleet and other general plant assets are assessed through in-house developed approaches.

For poles, discretionary replacement priority is based on three primary criteria:

- The estimated remaining life of the pole;
- Customers impacted by pole failure;
- Criticality of pole location

In order to optimize equipment value and minimize replacement costs, CPC has developed a procedure for re-use of equipment returned from the field. The procedure is in compliance with O. Reg. 22/04, section 6(1)(b) – Approval of Electrical Equipment and ensures that used equipment meet current standards and pose no undue hazard for re-use in new construction. Examples of equipment subject to potential reuse are distribution transformers and line openers. All equipment subject to reuse has to meet certain minimum condition criteria and has to be deemed safe to use by a competent person.

Asset investment determination - Asset replacement is considered annually as part of CPC's investment planning process along with the other capital projects scheduled for completion in the upcoming year. Non-discretionary asset replacements, due to near term significant safety or reliability issues are automatically included in the budget spend envelope. Discretionary asset replacements are prioritized and scheduled as described in section 5.3.1. Discretionary replacements provide a degree of planning flexibility to help keep annual capital expenditures stable. The outcomes of the investment planning process will align with the proposed budget or may indicate that the budget needs revision to adequately address underinvestment Risks. With increasing need to address assets at end of life, multi-year asset replacement programs have been structured to smooth out budget and resource impacts.

When assets are replaced as a result of system renewal investments, the new assets are incorporated into the inspection and maintenance programs. As the average health index of the group (i.e. poles) improves through system renewal investments, it should have a beneficial impact on how much effort is spent on reactive emergency maintenance. Due to the lengthy nature of the proposed replacement programs for existing assets in very poor and poor condition, significant reductions in historical reactive maintenance does not typically realized until program completion.

b. Lifecycle Risk management

CPC has determined that asset inspection, condition assessment and comprehensive data collection will provide a better understanding of each distribution asset's stage in their lifecycle which will lead to more cost effective decisions with respect to Risk management. This complements the information received through the maintenance programs to assess asset Risk.

Asset performance during an investment cycle is collected and utilized in the next investment planning period. Non-discretionary investments are automatically included in the investment plan regardless of Risk. Discretionary asset investment is valued and scored. The scoring process considers the implicit Risk of not investing in the upcoming investment cycle. For example, critical asset investments such as station transformers and 44kV plant will score relatively high on benefit compared to distribution transformer investment due to the higher widespread impact that a failure of a critical asset has. This has also led to the development of proactive replacement strategies for higher Risk high cost critical assets (i.e. poles and underground cable) and reactive replacement strategies for lower Risk low cost assets (i.e. distribution transformers).

It is evident that in discretionary distribution asset replacement investments, there is a need for a long term smoothed proactive investment program for pole and underground cable. The programs are structured to remain within OEB rate mitigation guidelines and will result in an increasing amount of Risk for those assets nearing end of life that await replacement towards the later years of the replacement program. In this sense Risk is balanced against the reality of unsustainable rate increases that would be needed to eliminate all asset Risk in a short period of time. Assets with the lowest life remaining index in a particular category (i.e. poles, UG cable) are addressed first. Other assets with higher remaining life are deferred to future investment periods. Individual asset priority position in the program will be managed as more asset information is obtained through ongoing annual inspection and testing so as to optimize replacement Risk decisions.

In consideration of CPC's Asset Management Objectives and the other drivers of investment planning, it has been determined that multi-year renewal programs for poles with less than 35% life remaining ("very poor" and "poor" condition) will best balance Risk, value and rate impact. A one year program has been established for the elimination of live front transformers. Other assets in similar condition will be dealt with on a reactive basis.

Asset	Quantity (<35% life)	Program length	Program Cost
Poles	1300+	5+ years	$10 M+
Live-front transformers	5	1 year	$295,000

Table 29 – Key Renewal Programs

The pole replacement program is expected to replace approximately 1070 of the 1300 poles currently in poor or very poor condition during the 2018 – 2022 DSP period. Long term replacement for material fleet and general plant assets will be accompanied by specific business cases as required.

5.4 Capital Expenditure Plan

CPC's Distribution System Plan details the programme of system investment decisions developed on the basis of information derived from CPC's asset management and capital expenditure planning process. Investments, whether identified by category or by specific project, are justified in whole or in part by reference to specific aspects of CPC's asset management and capital expenditure planning process.

CPC's Distribution System Plan includes information on prospective investments over a five year forward looking period (2018 – 2022) as well as planned and actual information on investments over the historical five year period (2013 – 2017).

5.4.1 Plan Summary

a. Capability to connect new load or generation customers

CPC's distribution system is efficiently utilized. The capability to accommodate new load growth is not constrained at the distribution station or feeder level. Redistribution of feeder loading subject to system optimization studies.

Based on the applications to connect new renewable energy generation, CPC has determined that there are no CPC limitations to the connections at present. CPC notes that two 4.16kV feeders that have REG connected are at capacity and unable to connect additional REG.

Generation connection capacity may be severely impacted by even a modest penetration of natural gas generation behind the meter. Interest in this type of generation has increased due to government subsidy programs. Natural gas generation has 5-7 times the impact on system capacity as renewable inverter based generation.

b. Total annual expenditures 2018 – 2022

The following table summarizes the planned capital expenditures, by investment category, over the period of the DSP:

	2018	2019	2020	2021	2022
System Access	$ 581,270	$ 311,956	$ 317,884	$ 323,923	$ 330,078
System Renewal	$ 1,895,340	$ 2,527,530	$ 2,283,120	$ 2,339,224	$ 2,562,300
System Services	$ 51,087	$ 52,058	$ 53,047	$ 54,055	$ 55,082
General Plant	$ 651,930	$ 364,816	$ 657,757	$ 585,755	$ 298,809
Total	$ 3,179,627	$ 3,256,361	$ 3,311,809	$ 3,302,958	$ 3,246,270

Table 30 – 2018 – 2022 Planned Capital Expenditures by Category

c. Effect of asset management and capital investment process outputs on capital expenditures

The asset management and capital investment process identify system access, system renewal, system service and general plant requirements. These requirements result in a list of non-discretionary and discretionary investments to be done over the investment period. Non-discretionary capital investment needs are documented, costed and scheduled according to timeline needs. Discretionary investments needs are documented, costed and prioritized according to Risk of deferral and the benefit each investment has towards achieving corporate asset management objectives, regardless of which investment category they reside in. In general, investments with a high safety Risk and benefit will take precedence over other investments. The capital budget is allocated among the categories according to the non-discretionary and prioritized discretionary investments in the final capital investment portfolio. The final investment portfolio considers the balance between achieving CPC's Asset Management objectives and impact on customer rates.

System Access – The investments are externally driven and generally non-discretionary. Timing of investment is driven by the needs of the external parties. Large projects, such major road widenings requiring plant relocation, require large amounts of capital and other resources. This category will generally have priority in capital budget allocation. Program spending is expected to be relatively consistent and limited over the forecast period and as such have less of an influence on remaining capital budget allocation.

System Renewal – Planning outputs have determined that a long term smoothed proactive investment program is required for replacement of pole assets. This need has been reflected in the increase of spending in this category over the period of the DSP. Other spending in this category will be for discrete projects and will be determined on the basis of ongoing system asset performance. Future funds have been reserved in this category for renewal needs due to unanticipated asset failure. Category spending will remain relatively consistent over the forecast period and does not detract from the other investment categories. Specific discretionary system renewal projects have been identified and prioritized.

System Service – System Service investment spending and timing is generally discretionary. There will be only minor System Service spending during the 2018-2022 investment period.

General Plant - General Plant investment spending and timing is generally discretionary. Fleet management has determined that material fleet investments can be smoothed over the 2018-2022 investment period.

d. Material capital expenditure projects/activities

In accordance with OEB Guidelines, CPC's 2018 *calculated* materiality threshold is $33k, based on 0.5% of CPC's 2018 distribution revenue requirement of $7M. For this report, CPC follows the OEB's *default* materiality threshold and provides justification for capital expenditures of $50k or higher. Material capital expenditures over the DSP period are summarized in the table below:

Material Capital Expenditures (2018 – 2022)							
Category	Category Total Expenditure $'000	Project Name	2018 $'000	2019 $'000	2020 $'000	2021 $'000	2022 $'000
System Access	$ 1,865,112	Residential and Commercial additions	$ 127,375	$ 129,795	$ 132,261	$ 134,774	$ 137,335
		Road relocations and Customer initiated	$ 772,785	$ 507,110	$ 516,746	$ 526,563	$ 536,568
		Smart Meters	$ 139,533	$ 142,184	$ 144,885	$ 147,638	$ 150,443
		Capital Contributions	-$ 458,423	-$ 467,133	-$ 476,008	-$ 485,052	-$ 494,268
System Renew al	$ 11,528,992	Planned pole replacements	$ 305,700	$ 311,400	$ 317,100	$ 322,800	$ 328,500
		Unplanned pole replacements	$ 101,900	$ 103,800	$ 105,700	$ 107,600	$ 109,500
		Pole Line Rebuild projects	$ 1,508,120	$ 1,546,620	$ 1,860,320	$ 1,809,922	$ 2,124,300
		UG primary cable replacement	$ -	$ 259,500	$ -	$ -	$ -
		Live Front transformer replacement	$ -	$ 306,210	$ -	$ -	$ -
System Service	$ 265,330	SCADA	$ 51,087	$ 52,058	$ 53,047	$ 54,055	$ 55,082
General Plant	$ 2,289,364	Vehicle Replacement	$ 500,000	$ 210,000	$ 500,000	$ 425,000	$ 135,000
		Computer Softw are/Hardw are	$ 100,000	$ 101,900	$ 103,836	$ 105,809	$ 107,819
Total	**$ 15,948,798**		**$ 3,148,077**	**$ 3,203,444**	**$ 3,257,888**	**$ 3,149,109**	**$ 3,190,280**

Table 31 – Material Capital Expenditures (2018 – 2022)

Material System Access projects consist of annual programs to connect residential and commercial customers and plant relocation due to road work.

Material System Renewal projects consist primarily of overhead pole line rebuilds.

Material System Service projects consist primarily of support spending for the SCADA system.

Material General Plant projects consist primarily of a large vehicle replacement and support spending for computer systems and office requirements.

e. Material impacts of Regional Planning Process/Infrastructure Plan

A South Georgian Bay/Muskoka Region Scoping Assessment Outcome Report was published in June 2015. The Integrated Regional Resource Planning (IRRP) Terms of Reference for the Parry Sound/Muskoka sub-region is expected to be released in Q4 2016.The IRRP is not expected to have any material impact on the 2018 – 2022 DSP.

f. Customer engagement activities to ascertain plan alignment

Customer engagement is considered essential to achieving CPC's Customer Focus outcomes. CPC uses a variety of activities to engage customers and determine their preferences for the development of CPC's distribution system going forward.

In September 2017, CPC held a Public Information Centre on its draft DSP. X members from the public attended the PIC. The comments and customer preferences received at the PIC will aid refining and finalizing the DSP.

Another method CPC uses is the customer satisfaction survey. The satisfaction survey is done on a periodic basis to compare evolving customer satisfaction over time. CPC believes that customer engagement with respect to DSP outcomes should provide useful information, be cost-effective, and be able to engage as many customers as reasonably possible. The goal is to capture preferences with respect to the underlying principle of the DSP - to maintain existing service levels over the period of the plan. One way to accomplish this is through telephone based customer surveys. Knowledge of historical and present customer high level preferences helps with the initial development of the DSP.

Customer surveys provide a high level assessment of customer preferences with respect to service reliability and operational effectiveness. For accuracy purposes, survey samples should be representative of the service territory population. The 2014 and 2017 survey results indicate satisfaction with current reliability service performance levels which indicates that plan efforts to maintain historical reliability levels are reasonable thereby supporting system renewable efforts and prudent smart grid development. Concern about rates supports the need to consider rate mitigation efforts while managing Risk and smoothing spending over time for discretionary investments. Survey results are implicitly considered in the development of the asset management strategy, objectives and plans.

According to the 2014 residential and commercial customer survey, together with the CHEC 2013 survey results for comparison sake, the most important service improvements that CPC could undertake, from the customer's perspective, are shown in Table 32 below:

One or two most important things 'your local utility' could do to improve service		
	CPC 2014	CHEC 2013
	% of all suggestions	% of all suggestions
Better prices/lower rates	53%	45%
Improve/simplify/clarify billing	8%	12%
Remove hidden costs on bills	8%	5%
Information & incentives on energy conservation	7%	5%
Better communications with customers	6%	8%
Better on-line presence	6%	5%
Eliminate/Concerns about SMART meters	5%	8%
Be more efficient	5%	4%
Don't charge for previous debt	5%	3%
Improve power reliability	4%	10%
Staff related concerns	4%	8%
Increase service hours/availability of hydro representative	4%	3%
Better Maintenance	1%	-

Table 32 – Customer service preferences (2013 & 2014 UtilityPULSE Surveys)

In light of the 2013 Ice Storm and aging electricity distribution infrastructure in general, the 2014 UtilityPULSE residential and commercial customer survey asked customers for their views regarding prioritizing investments and activities. Survey respondents could score an investment/activity from Very High Priority to Very Low Priority. The top two “Very High Priority” and “High Priority” investment needs for all participating Ontario LDCs is shown in the table below:

Priority investments	
Top 2 Boxes "Very High Priority" and "High Priority"	Ontario LDCs
Maintaining and upgrading equipment	83%
Reducing the timeneeded to restore power	79%
Investing more in the electricity grid to reduce the number of outages	74%
Educating customers about energy conservation	74%
Burying overhead wires	60%
Investing more in tree trimming	58%
Providing sponsorship to local community causes	43%
Providing more self-serve services on the website	38%
Developing a smart phone application	31%
Making better use of social media	30%

Table 33 – Customer Priority Investments

The top priority supports the DSP objective of maintaining existing reliability standards through the plan period. The next two priorities indicate a desire for improving response time and reducing outages.

CPC has also posted the 2018 – 2022 DSP to its website along with a short survey form for customers to provide feedback about the DSP and their preferences. Comments and preference information received will aid refining and finalizing the DSP.

Project information handouts have been provided to customers affected by specific projects proposed in the DSP. Handouts/flyers have been hand delivered to customers. The flyers have some basic information on the project with a link to the CPC website for more information. Customers have been provided with telephone contact information should they wish to leave comments on the proposed works (and if they want to be called back for more discussion). The handout also advised customers of the September x DSP Public Information Centre.

CPC also presented the 2018 – 2022 DSP investment plans to the Town of Collingwood Chamber of Commerce to solicit feedback from the commercial sector. Feedback was….. As part of its long term engagement strategy, CPC staff plan to update the Chamber of Commerce, on an annual basis, on the upcoming capital works plans for the following year.

CPC often has presence at local events (i.e. Great Northern Exhibition, Environment Networks summer day camp, etc.) where information (i.e. CDM programs) and knowledge (i.e. Electrical Safety) is provided to attendees. CPC has found this to be a low cost method of engaging its customers.

Weekly information e-mails are sent to a number of large industries as well as the media throughout CPC service territory.

Council engagement is undertaken as described in section 5.4.2d. As part of its long term engagement strategy, CPC staff plan to update the Council, on an annual basis, on the upcoming capital works plans for the following year.

Public Safety workshops are held at local schools on an annual basis.

Customer meetings are held generally to discuss issues that are unique to a specific customer or a small group of customers.

Meetings are held on an ongoing basis with customers to promote and market CPC's CDM program and advise on connection process for distributed generation.

The corporate website and Twitter feeds also provide forums for customer engagement. Information obtained from customers, as a result of continuous feedback through the year, is considered in the development of the investment portfolio and the investment prioritization process.

In summary, CPC's customer engagement strategy and plan over the period of the DSP is as follows:

2018	2019	2020	2021	2022
Council/Chamber of Commerce Information Session	Council/Chamber of Commerce Information Session	Council/Chamber of Commerce Information Session	Council/Chamber of Commerce Information Session	Council/Chamber of Commerce Information Session
-	Customer survey -	-	Customer survey -	-
Local event presence	Local event presence	Local event presence	Local event presence	Local event presence
Public Safety Workshops	Public Safety Workshops	Public Safety Workshops	Public Safety Workshops	Public Safety Workshops
Municipal consultation	Municipal consultation	Municipal consultation	Municipal consultation	Municipal consultation
Customer meetings	Customer meetings	Customer meetings	Customer meetings	Customer meetings
CDM/DG meetings	CDM/DG meetings	CDM/DG meetings	CDM/DG meetings	CDM/DG meetings
Weekly major	Weekly major	Weekly major	Weekly major	Weekly major

account updates	account updates	account updates	account updates	account updates
Website/ Twitter – general info	Website/ Twitter – general info	Website/ Twitter – general info	Website/ Twitter – general info	Website/ Twitter – general info

Table 34 – CPC 5 Year Customer Engagement Plan

The engagement strategy is primarily achieved through the use of internal resources and is not expected to exceed $25,000 per annum for external support needs.

g. System forecast development 2018-2022

It is expected that the operational and service requirements driving CPC's capital expenditures, and found within its DSP, will generally remain consistent through the 2018 to 2022 planning window. CPC expects moderate load and customer growth in line with development plans that directly impact CPC's service territory:

1. Ontario Places to Grow Act
2. Collingwood Community Based Strategic Plan
3. Town of Collingwood Official Plan
4. Thornbury, Stayner, Clearview growth plans
5. County of Simcoe Official Plan

System Access investments will provide for new customer connections over the period of the DSP. This will be accommodated through existing infrastructure. There are two identified pole relocation projects due to road widening by the Town.

System Renewal investments (end of life replacement) will ensure that customer service levels with respect to reliability are maintained. Inspection and performance analytics help direct preventive maintenance to specific at-Risk equipment and extend further the safe reliable useful life of all equipment. Major focus will be on pole replacement due to end of life status. Over 1600 poles have been determined to be in poor or very poor condition. Approximately 1400 of these poles will be addressed by replacement programs through the DSP period.

Smart grid investments will be pursued where prudent and prioritized. At this time there are no plans to increase the present level of automation (i.e. overhead switch automation) in the distribution system. SmartMAP use and information development will continue to be a focus of Operations efforts.

The accommodation of renewable energy generation projects is not expected to drive any significant system developments over the next five years.

h. Total capital cost of planned projects/activities

Capital investments related to:

1. customer preferences (CP);
2. technology-based opportunities (TBO) and
3. innovative processes, service, business models or technologies(IP/T)

are summarized in the table below:

Category	Investment Name	Cost	Description
CP	System Renewal	$10M	Replacement of end of life plant to maintain current levels of reliability

TBO	N/A	N/A	N/A
IP/T	SCADA/SmartMAP	$0.3 M	Continue development of SCADA and SmartMAP systems to provide more timely detailed and accurate information to Operations staff

Table 35 – Capital Investments Customer Preferences/Technology/Innovation

CPC believes that it has incorporated customer preferences through the feedback it has received from the communication channels that it maintains as described in Section 4.5.1(f).

CPC has successfully engaged customers and promoted their participation in CDM and DG programs. The CDM 2013 Annual Report submitted to the OEB demonstrated CPC's efforts in delivering the OPA-Contracted Province-Wide CDM Programs to the residential and commercial customer sectors.

CPC is partnering with PowerStream Inc. to deliver a variety of CDM services and offerings to CPC customers during the period of the DSP.

Near term actions to support the partnership program are not expected to have a material impact during the 2018 – 2022 period of the DSP.

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5.4.2 Capital Expenditure Planning Process Overview

This section of the Distribution System Plan (DSP) provides a high level overview of CPC's capital investment planning process. The capital investment planning process is embedded within CPC's Asset Management process.

The annual Asset Management capital planning investment cycle consists of seven steps:

1. Review of System Performance
2. Determination of Asset Inventory condition and augmentation needs
3. Set preliminary budget based on investment drivers
4. Establish investment requirements
5. Develop and prioritize budget investment portfolio
6. Budget investment alternatives review; budget investment approval
7. Budget investment plan implementation

The planning investment process is linked to CPC's Asset Management objectives which guide the investment decision making.

a. CPC Capital expenditure planning objectives, criteria and assumptions

Planning Objective

CPC's planning objective can be summarized as determining the optimum level of investment in and configuration of distribution capacity while having due regard to:

- corporate objectives;
- stakeholder interests;
- relative costs and benefits associated with distribution development strategies;
- acceptable levels of Risk;
- environmental factors that directly or indirectly impact on the efficient and reliable operation of the distribution network.

Planning Criteria

In terms of the overall planning criteria, CPC, like most Ontario utilities, has adopted a deterministic philosophy for distribution system planning. Contingency criteria drive the planning and capital works program. For example, most transmission systems have an N-1 contingency level which means that loss of any one element (circuit, station transformer, etc.) does not result in an interruption to customers. Most distribution utilities operate at an N-0 level. In most situations, customers will experience an interruption, upon loss of a distribution system element (pole, transformer, etc.), while backup capacity is engaged or an asset is replaced. Outage time is also impacted by the level of distribution automation present in the system. Deterministic planning levels (N-0, N-1, N-2…) determine levels of investment and reliability of supply.

CPC planning criteria (N-0) will trigger an investment need when the capability of an asset, such as a substation transformer, is exceeded under normal or contingency operating standards depending on the type of asset.

CPC, like other distribution utilities strives to ensure its distribution system provides a reliable level of service to existing customers and connection capacity for forecasted demand growth and as such must be able to handle customer supply needs during normal and certain contingency situations. Overloading of distribution equipment, as a result of inadequate investment, is avoided as much as possible.

Municipal Station Transformers

Municipal Stations are critical components of the distribution system whose service disruption results in a large number of customers being out of supply. To this end distribution stations are planned, configured and loaded to 75% normal rating so as to provide some measure of reserve capacity for contingency situations. A distribution station transformer should not be loaded above its normal rating during non-contingency situations. Operating above normal rating will result in a shortening of the transformer service life. Under contingency situations, the transformer can be operated at its emergency rating for a short period and load is to be transferred to other distribution stations, without exceeding the normal rating of the distribution station transformers or circuits receiving the load, as soon as possible.

44kV, 8.32 and 4.16kV feeders

44kV feeders are the main supply feeders from HONI TS to CPC owned MS. 44kV feeders are critical components of the distribution system. Service disruption results in a large number of customers being out of supply. To this end 44kV feeders are planned, configured and loaded so as to provide some measure of reserve capacity for contingency situations.

8.32kV and 4.16kV feeders traverse the distribution area with multiple interconnections between the feeders at various points. In order to facilitate this restoration capability, normal feeder loading is planned to be a maximum of 50% of circuit rating under normal operation. Under contingency situations, all interrupted load should be restored within a short time period. Sectionalizing devices are installed on circuits to isolate faulted conductors and to permit the circuits to be subdivided if required. Normally open ties are provided between adjacent circuits to permit transfer of load during contingencies.

Other distribution assets service a much smaller number of customers and may not have as high a disruptive impact when unavailable. To this end, planning criteria are established to provide planners with guides to the design and operation of the distribution system under normal and contingency situations.

The distribution system will achieve certain levels of reliability performance depending on the planning criteria in place and asset lifecycle support programs. For CPC, the planning criteria should ensure that the following annual reliability service level objectives are achieved:

Service function	**Objective**
System Outage Duration	SAIDI at/below OEB 5 year baseline target
System Outage Frequency	SAIFI at/below OEB 5 year baseline target
Index of Reliability	IOR within range of past 5 year performance
Emergency response	60 minutes maximum/80% of the time

Table 36 – Reliability performance objectives

The 2010 OEB sponsored Pollara survey solicited the opinions of consumers from across the Province regarding electricity outages and other reliability related issues. The survey indicated that the majority of consumers are generally satisfied with current levels of system reliability and do not favour increasing their rates in order to fund improvements in system reliability. CPC believes that maintaining reliability performance within range of OEB targets is appropriate and sustainable. In this sense CPC is seeking to balance reliability performance with customer cost.

The planning criteria assume:

- that equipment maintenance, refurbishment and replacement programs are in place to ensure that the capacity and capability of the distribution system is maintained at reasonable level of Risk of disruption due to lifecycle related equipment failure;
- that incidences of extreme weather will continue to be manageable under existing standards of design and construction.

The following is a summary of CPC's key planning criteria:

Criteria	Planning guideline
General	In planning the system, “good utility practice” shall be followed.
System Voltages	The primary supply voltages for the CPC Service area shall be 44kV , 8.32kV or 4.16kV
Municipal Stations	Municipal Stations will be 44kV primary supply. The MS secondary supply voltage shall be 8.32kV or 4.16kV. Minimum MS transformer size shall be 5 MVA. Maximum MS station size shall be 2 x 5MVA transformers where justified due to load growth and available feeder egress
	MS Transformer planned loading shall be 75% of normal nameplate rating to allow for contingency capability.
	MS Transformers maximum allowable loading, under normal conditions shall be their ONAN ratings. Under contingency conditions, MS transformers can be loaded to ONAF ratings for short time periods only as this will result in loss of transformer life. The distribution system shall be constructed and configured to allow for MS transformers to be backed up by one or more neighbouring MS stations in the event of a station contingency situation.
	For the purpose of determining the number of feeders emanating from a MS, an average loading of 20 MVA per 44kV feeder, 3 MVA per 8.32kV feeder and 1.2 MVA per 4.16kV feeder will be used.
Feeders	All 44kV, 8.32kV and 4.16kV feeders shall be designed for full backup capability over peak loading conditions through the switching of load to an adjacent feeder or multiple adjacent feeders. In order to facilitate this restoration capability, normal feeder loading will be planned to a maximum of 50% of circuit rating under normal operation. Overhead circuit rating is primarily a thermal rating determination such that the conductor does not sustain significant loss of strength due to annealing over its useful life. Underground circuit ratings are based on applicable cable ampacity ratings based on the type of cable and conditions of installation, to optimize cable loss of life over its lifecycle.
	Overhead 44kV shall be 556 kcmil Al. on poles with armless construction. Overhead 8.32kV and 4.16kv shall be 336 kcmil Al conductors. Overhead laterals of more than 200A that could be tied to another feeder or feeder lateral will also have similar size conductors for the respective voltage class.
	Overhead 8.32kV feeders shall be 556 kcmil Al. on poles with armless construction. Laterals shall be 3/0 Al
	Underground 4.16kV feeders in subdivisions shall be 1/0 TRXLPE CU cables Maximum cable loading shall be 200A
	Current unbalance is defined as the maximum phase current deviation from the average phase current, as a percentage of the average phase current. Feeders with a phase current deviation in excess of 20% from average will be considered for rebalancing. New single phase load additions should be connected to the phase with the least connected KVA, if it is available, to maintain a balanced circuit.
	Under normal and contingency situations, circuit voltage drop shall be managed such that customer service voltages shall comply with the standards of the Canadian Standards Association, CSA Standard CAN3-C235 (latest edition).
	Losses on three phase feeders should be kept to a minimum through the use of appropriately sized conductor, optimal feeder loading and load sharing, phase balancing, and in some cases, applications of shunt capacitors. At the present time the industry standard for a typical urban utility is in the range of 2.5 - 3.5%.
Planning Horizon	The planning horizon shall be 5 years to align with the Distribution System Plan requirements. Regional planning exercises may identify planning needs in excess of the DSP 5 year planning horizon
Distribution Automation	Distribution automation through remote switching is to be provided, when cost justified, to ensure that load lost during single contingencies can be restored in a minimum amount of time
Protection Philosophy	CPC 44KV is primarily an overhead distribution system. Feeder protection shall incorporate appropriate auto-reclose settings to mitigate the impact of transient faults. In certain circumstances the auto-reclose setting will be disabled where all faults on the circuit are expected to be permanent in nature. Trip saving protection will be enabled to allow fuses and reclosers to isolate faults where they provide the first line of protection
Distribution Transformers	Distribution transformers with a normal residential load profile can be loaded up to 150% of nominal rating. For other loads, 130% of nominal rating
Fleet and tools	Replacement of fleet vehicles and tools shall be scheduled and prioritized to ensure the reliable and timely execution of maintenance and capital expenditure programs.
Equipment Asset Management	Equipment shall be procured, installed, maintained and disposed of through CPC’s Asset Management process
Undergrounding	Undergrounding of existing CPC overhead assets shall be considered where there are external cost recovery mechanisms, outside the electricity rate setting process.

Table 37 – CPC Planning Criteria

Distribution System Contingencies

Contingency Plans are required to deal with any asset related event that affects the proper functioning of the distribution system. Contingency planning deals with potential high-impact/low-probability (HILP) events that can have major repercussions on the distribution system and CPC customers. This will mostly apply to critical assets such as distribution station transformers and 44kV feeders. All other events, that are generally regular occurrences, low-impact/low-scope and have established processes to deal with them, are not detailed here. The HILP events considered here are shown in the Table 38 below:

Asset Class	Contingency Event	Contingency Plan
MS Power Transformers	Transformer failure requiring off-site servicing	1. Spare Transformer (from CPC or CHEC) 2. Plans to move spare to affected MS 3. Ties to alternate MS supplies
MS Circuit breaker or fuses	Circuit breaker failure	1. Spares – Critical parts list 2. Contact plan for manufacturer repair support 3. Feeder emergency loading capability 4. Ties to alternate MS supplies
MS Feeder cables	Failure of one or more underground cables	1. Spare cable reel 2. Ties to alternate MS supplies
MS RTU	Failure of RTU leading to loss of station telemetry/control	1. Standby staff to man station (if required) 2. Contact plan for manufacturer repair support
Station Protective Devices	Device failure leading to full/partial loss of station	1. Spare – Critical Parts list 2. Ties to alternate MS supplies
Poles/conductors	Loss of high number of pole structures through high impact event (severe weather, etc.)	1. Stock poles/conductors 2. Supplier stock 3. Neighbouring LDC stock

Table 38 – Contingency events and plans

In all cases if available contingency measures prove insufficient, load shedding may be required to ensure equipment is not loaded beyond approved tolerances.

It is CPC's assessment that the distribution system has sufficient capacity to accommodate foreseeable renewable generation connections within the period covered by the Distribution System Plan. CPC's planning objective with respect to renewable generation is to continue to facilitate the connection of renewable generation in a timely manner consistent with the provisions of the Distribution System Code.

Distribution Planning is part of the Asset Management process and is a year round activity. Issues of growth and reliability are evaluated on an ongoing basis to determine optimal solutions that feed into the investment process. Computer modelling tools, such as DESS, are used in conjunction with GIS information to evaluate distribution system configuration performance with respect to the planning criteria. Solutions incorporate a balance of corporate and stakeholder interests.

b. CPC policy and procedure on incorporating non-distribution system alternatives

CPC does not have any specific policy or procedure related to utilizing non-distribution system alternatives for system capacity or operational constraint relief. CPC's activities in this area are delivered through the CPC 2015-2020 CDM programs in accordance with the CDM requirement included in CPC's licence as issued by the OEB. CPC's total 2015 – 2020 CDM target is 16.86 GWh as determined by the IESO.

CPC's 2015-2020 CDM programs are consistent with OEB policy and the OEB's 2015 CDM Guidelines of putting conservation first into distribution planning. CPC's CDM programs, provided through the PowerStream partnership, are designed to reduce electricity consumption and draw from the grid upstream of the customer. CPC's CDM program consists of IESO funded programs and specific programs that are to be funded solely through distribution rates.

Proposed distribution rate funded programs <u>may</u> consist of:

1. CDM programs that target peak demand (kW) reductions to address a local constraint of CPC's distribution system.
2. Demand response programs whose primary purpose is peak demand reduction in order to defer capital investment for specific CPC distribution infrastructure.
3. Programs to improve the efficiency of the distribution system and reduce distribution losses. (i.e. re-conductor to larger size, voltage conversion, etc.)
4. Energy storage programs whose primary purpose is to defer specific capital spending for the CPC distribution system

CPC notes that non-distribution investments to relieve capacity or operational constraints need to be optimal solutions. The solution must be optimal with respect to the uncertainty of future system loading. The non-distribution system investments need to ensure that distribution system investments can be deferred by a specific time period with certainty. Future uncertainties about local distribution capacity demand need to be factored into the value of the non-distribution system investment.

The impact of CDM programs is factored into the load forecast for determining capacity growth/decline impacts. The 2015 – 2020 forecasted CDM impacts are noted in Table 38 below:

	CDM MW	CDM MWh
2015	0.28	1,738
2016	0.32	2,047
2017	0.44	3,044
2018	0.59	3,231
2019	0.58	3,049
2020	0.93	3,751
Plan Total	**3.14**	**16,860**

Table 39 – Forecast CDM contributions

The amount of proposed CDM program impact, during the period of the Distribution System Plan does not offer any significant capacity or operational constraint relief to CPC's distribution system.

c. Processes, tools and methods used to identify, select, prioritize and pace projects in each investment category

Project Identification

The projects that CPC selects for its capital budget are the ones that are required to ensure the safety, efficiency, and reliability of its distribution system to allow CPC to carry out its obligation to distribute electricity within its service area as defined by the Distribution System Code.

System Access projects such as development and municipal plant pole relocation projects are identified throughout the year by external proponents. Most of these projects are non-discretionary in nature and are budgeted and scheduled to meet the timing needs of the external proponents.

System renewal projects are discretionary in nature and are identified through CPC's Asset Management process. The project needs for a particular period are supported by a combination of asset inspection, individual asset performance, and asset condition assessments.

System Service projects are discretionary in nature and are identified through CPC's Asset Management process and operational needs to ensure that any forecasted load changes that constrain the ability of the system to provide consistent service delivery are dealt with in a timely manner.

General plant projects, such as fleet vehicle acquisition or replacement, software/hardware, etc., are discretionary in nature and are identified internally by specific departments (engineering, finance, operations, administration, etc.) and supported through specific business cases for the particular need.

Project Selection and Prioritization

Non-discretionary projects are automatically selected and prioritized based on externally driven schedules and needs. Most System Access projects fall into this category and may involve multi-year investments to meet proponent needs. Pole relocations due to road widenings are examples of this.

Discretionary projects are selected and prioritized based on value and Risk assessments for each project. Most System Renewal, System Service and General Plant projects fall into this category and some projects, such as System Renewal – Poles, may involve multi-year program investments to meet Asset Management objective needs.

Reliability and safety are key considerations in project prioritization. In determining reliability priorities, CPC considers the following characteristics of its distribution system:

- Failure of one 44 kV feeder line interrupts approximately 20% of total system load
- Failure of a municipal station interrupts approximately 10% of total system load
- Failure of a 8.32kv or 4.16 kV feeder line interrupts approximately 2-3% of total system load
- Overhead lines take hours to repair while underground cables take days

In this sense, when prioritizing individual projects, 44 kV asset impacts will score relatively high in value and Risk impact followed by municipal stations and 8.32kv and 4.16kV facilities.

Project Pace

Project pace for System Access projects is generally determined by external schedules and needs. System Service and General Plant projects tend to be planned, short duration projects and most are paced to begin and be completed within a particular budget year. System Renewal projects tend to be multi-year programs and are paced to balance the Asset Management objective needs of the particular program with regard to available resources and managing the program impacts on the customer's bill. In this sense program value and deferral Risk are weighed against the ability of the customer to pay.

CPC's multi-year System Renewal programs have been prepared and paced based on CPC's desire to mitigate bill impacts for expenditures within CPC's control. OEB rate mitigation guidelines are targets that CPC strives to adhere to. CPC's asset management process identifies the type and quantity of assets (i.e. km of underground cable) that are expected to be proactively replaced due to end of life condition and provides a recommended and prioritized renewal investment profile. This recommended profile is used to guide multi-year capital investment requirements. CPC has developed multi-year programs that focus on proactively replacing key assets in the "very poor" and "poor" condition over the DSP plan period. Assets in "Fair" or better condition will not be addressed until their condition deteriorates to the "poor" or "very poor" stage. It is recognized that replacement pace is a balance between increasing Risk of asset failure and customer outage impacts/costs with the need for rate mitigation.

All potential discretionary Capital projects in the System Renewal, System Service and General plant categories are submitted for project scoring and prioritization. Project scopes, justifications and cost estimate are prepared for each project to aid in determining overall project effectiveness, value, and timing.

CPC uses a Risk and value scoring mechanism developed internally to classify and prioritize investments. The scoring mechanism links the Risk and value of executing the project with CPC's weighted corporate and asset management goals.

Objective	Weight
Safety	0.25
Reliability	0.20
Customer Service	0.20
Financial Integrity	0.15
Effective Integration	0.10
Environmental	0.05
CDM	0.05
Total	**1.00**

Table 40 – Objective weighting summary

Safety – This objective has been given the highest priority by CPC. Safety comprises organizational efforts to ensure that worker and public safety is paramount in day to day activities. No other objective is higher than safety. The Safety objective is assigned a weight of 0.25

Reliability – This objective is the second highest priority. Together with safety it is a key corporate objective outcome. In customer surveys, it has ranked high in importance of customer needs. The Reliability objective is assigned a weight of 0.20

Customer Service – This objective ranks relatively high in ensuring that business outcomes meet the value needs of the customer. The Customer objective is assigned a weight of 0.20

Financial integrity - A stable rate of return, low electricity rates and ability to sustainably invest in distribution system access, service, renewal and general plant are key to the long term success of this objective. Balancing of stakeholder interests in this area is an ongoing exercise. In customer surveys, low electricity rates ranked first in importance of customer needs. In consideration that CPC's controllable portion of the customer bill is less than 25%, the Financial integrity objective is assigned a weight of 0.15

Effective integration – This objective ensures that continual improvement of processes and practices ranks high in consideration of program development and deliverables. It is assigned a weight of 0.10.

Environmental – It is recognized that environmental considerations benefit the community as a whole. Considering the relative ability of CPC to affect the environment (e.g. oil spills, aesthetics, etc.) this goal does not carry the priority of the previous goals. The Environmental objective is assigned a weight of 0.05

CDM achievement –This successful delivery of the CDM program supports public policy objective of electricity conservation. The CDM objective is assigned a weight of 0.05.

Investments not prioritized for a particular investment year are pooled with other deferred investments and rescored and prioritized for future investment years.

d. Customer engagement to identify needs, priorities and preferences

As stated in Section 5.4.1(f), CPC uses a variety of activities to engage customers and determine their preferences for the development of CPC's distribution system going forward. This aids in investment decision making. CPC has noted that customer consultation is challenging for some issues, due to their complexity, however the customers do appreciate the opportunity to be heard especially on issues of a local nature.

CPC surveys covering residential and commercial customers provide a high level assessment of customer preferences with respect to service reliability and operational effectiveness. Survey results are implicitly considered in the development of the asset management strategy, objectives and initial stages of annual plan development. The 2014 and 2017 surveys indicated that cost of power and maintaining reliability are key issues of interest to the customer. This supports CPC's position on proactive system renewal related planned replacement programs for key assets at end of life such that current reliability levels are maintained.

In the past, CPC has provided an annual presentation of their "Annual Report" to Council. In 2015 this practice was augmented to provide new orientation to the new Town of Collingwood Council. Two information sessions (February 10th and 11th) were hosted where CPC staff answered questions and went through CPC's 18-month review document. The information sessions were designed for two-way communication. CPC's meeting goal was to update Council, as representatives of CPC's customers, with respect to what is happening in their community with respect to CPC. The second goal of the meeting was to solicit Council feedback on electrical supply issues that are communicated to them from municipal residents and commercial establishments. Some information may be known through direct communication by customers to CPC but Council members tend to accumulate specific consumer issues, viewpoints and overall perception of service through ongoing discussion with their constituents and this has value to CPC. In 2016 it was determined by Town staff that submission of the Annual Report document as an information item, without presentation, was sufficient for their consultation needs.

Municipal development planning consultation, specifically with respect to road widening projects or plant undergrounding projects is normally performed in advance of annual plan development as design parameters, work schedules, resource allocation, cost agreements all have to be arranged. Notice to relocate plant by a Road Authority can be given in as little as 60 days under the Public Service Works on Highways Act but normally more time is allowed (6 months minimum) to allow for the necessary plans and resources to be compiled.

CPC provides comprehensive information on its website for customer education and information on the aspects of CPC electricity supply. Consumer information is provided in a number of sections:

- About Us
- Accounts and Billing
- Conservation
- Safety and Services
- News & Events
- Publications
- Outages

CPC's Twitter feeds provide customers with daily information of changes in the electrical market and current event related to the distribution system. Website is used for specific messaging of programs/initiatives/issues requiring more detailed information (i.e. Public Awareness Electrical Safety telephone survey).

The website also provides CPC contact information for the customers to address any inquiries that they may have.

Customer needs and preferences with respect to CDM and DG programs are determined at an individual level in discussions with program participants.

In carrying out distribution activities to support the Corporate Mission and Vision statements, stakeholder interests have to be considered and factored into the short and long range planning processes. Stakeholder interests vary and at times can be either complementary or conflicting. As a part of the planning process, some basic assumptions are made about the stakeholder interests. **The assumptions represent high level utility assessments of key stakeholder class attributes that the utility has observed from many years of historical interaction with each respective stakeholder group**.

The assumptions and related stakeholder interests are shown in Table 40 below:

, Stakeholders	Stakeholder Needs	Stakeholder Interests	Stakeholder Perception of Planning Risks
CPC Corporation	Accurate external/internal information to set policy	Achieve mission vision and corporate objectives	Financial loss due to sub-optimization of operations; brand value deterioration
CPC Employees	Safe and stable work environment; skills development	Long term productive relationship with employer	Employment instability; unsafe work environment
Shareholders	Stable rate of return	Safe long term investment	Financial and political pitfalls
IESO (OPA)	Accurate load forecasting; meeting CDM targets for LTEP; accurate real-time information and market rule compliance by market participants	Comprehensive utility forecasting process; LDC delivery of CDM programs; LDC adherence to technical and communication protocols	Inaccurate information contribution to Regional planning processes; CDM targets not met; inaccurate or untimely information for market operations
HONI	Information to determine short, medium and long term local and regional infrastructure needs.	Coordination of transmission and distribution growth needs; LDC participation in Regional Planning	Inaccurate forecasts affecting resource commitments; Inaccurate information contribution to Regional planning processes
Generators	Stable market and ability to connect to distribution system	Clear rules and processes for connection	Distribution congestion affecting plant location and costs
Retailers	Reliable supply to customers; efficient business processes	Maximize contract revenues; customer relationship	Loss of revenue; loss of customers
Provincial Government	Efficient, low cost and reliable market	Reliable supply to stimulate growth and political goodwill	Localized negative political impact
OEB	Efficient, low cost and reliable market; regulatory compliance	Minimization of regulatory intervention	Regulatory intervention and political impact Risks
ESA	Public electrical safety	Utility construction built to Reg. 22/04	Public safety Risk if plant not built/maintained to code(s)
Municipalities(non-shareholders)	Reliable supply to customers	Consultations on activities within municipal boundaries; visual aesthetics	Supply/reliability shortfalls affecting their constituents
Residential Customer	Reliable supply and low rates	Aesthetics	Supply/reliability shortfalls; price concerns
Small Commercial	Reliable supply and low rates	Rate stabilization or reduction	Supply/reliability shortfalls; price concerns affecting business plans
Large Commercial/Industrial	Reliable supply and low rates	Rate stabilization or reduction	Supply/reliability shortfalls; price concerns affecting business plans

Table 41 – Stakeholder Needs, Interests and Perceptions

e. Methods and criteria used to prioritize REG investments

The prioritization process for REG expansions is the same as for distribution system expansion projects where the REG expansion is triggered and driven by customer requirements.

When CPC is required to do an expansion or enhancement to the distribution system to connect an embedded generation facility, the provisions of the OEB DSC Section 3.2 will apply. CPC will perform an economic evaluation to determine the generator's share of the present value of the projected capital costs and ongoing maintenance costs of the expansion. CPC assumes that future revenue and avoided costs will be zero.

CPC does not plan to connect any CPC owned renewable generation during the period covered by the Distribution System Plan.

5.4.3 System Capability assessment for renewable energy generation

a. Applications from renewable generators > 10kW

CPC has connected six renewable energy generators to date, as shown in Table 42 below:

Address	Municipality	Technology	kW	HONI TS & Feeder	Connecting Feeder
12 Hurontario Street	Collingwood	Rooftop Solar	135	Stayner TS – M3	M3 (44kV)
6 Cameron Street	Collingwood	Rooftop Solar	325	Stayner TS – M3	M3 (44kV)
15 Dey Drive	Collingwood	Rooftop Solar	100	Stayner TS – M8	M8 (44kV)
300 Peel Street	Collingwood	Rooftop Solar	50	Stayner TS – M8	CW MS3-F1 (4.16kV)
300 Spruce Street	Collingwood	Rooftop Solar	75	Stayner TS – M3	CW MS4-F2 (4.16kV)
12 Bridge Street	Thornbury	Hydro Electric	120	Meaford TS – M2	TH MS1-F1 (4.16kV)

Table 42 – List of FIT connections

b. Renewable generation connections anticipated 2018 -2022

In 2014 the IESO released their FIT 3.0 Procurement Offer list. There is one 130 kW FIT connection anticipated during the 2018-2022 period based on FIT 3.0 applications. If the project proceeds and the Connection Impact Assessment passes, it will be connected to the F4 feeder fed from Collingwood's MS6.

Address	Municipality	Technology	kW	HONI TS & Feeder	Connecting Feeder
11521 Highway 26 West	Collingwood	Solar PV (Rooftop)	130	Stayner TS – M3	CW MS6-F4 (4.16kV)

Table 43 – Anticipated DGs 2018 – 2022

It is expected that all other renewable energy generator connections will be at the micro-FIT level during this period.

c. Capacity to connect REGs

The CPC distribution system (MS stations, feeders) have capacity to connect DGs as noted in Appendix D. CPC's distribution system operates primarily at 4.16kV, with some 8.32kV feeders in Stayner and Thornbury, thereby limiting the amount of available distributed generation that can be connected to any one feeder. Approximately 3.3MW would be available for DG connections in CPC's service territory.

A Threshold Allocation Assessments has been obtained from HONI for the Stayner TS M3 feeder as follows:

Station & Feeder	TAA(kW)	REG connected(kW)	Balance
Stayner TS – M3	2000	535	1465

Table 44 – HONI TS station capacity for DGs

d. REG connection constraints

There are two CPC feeders that have REG connected (Collingwood MS5-F4 and Thornbury MS1-F1) and are unable to connect any additional REG.

The CPC service area is embedded within the Stayner TS and Meaford TS HONI 44kV feeder system.

The HONI Capacity Evaluation tool indicates that there is available HONI 44kV feeder REG capacity in excess of CPC's connection capacity except for the Stayner M8 feeder which is currently limited to a little over 740kW of connection capacity. All REG connections are assumed to be Solar PV or Wind for the purposes of this assessment.

As an embedded LDC in the Hydro One System, CPC is subject to the Hydro One rule of 7% of Max Peak Load for F Class Feeders for determining Distributed Generation available capacity.

e. Embedded distributor connection constraint impacts

There are no embedded distributors in CPC's service territory.

5.4.4 Capital Expenditure Summary

Capital Expenditure Summary

Category	Historical (previous plan and actual)															Forecast (Planned)				
	2013(CGAAP)			2014(CGAAP)			2015(IFRS)			2016(IFRS)			2017(IFRS)			2018	2019	2020	2021	2022
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var					
	$'000	$'000	%	$'000	$'000	%	$'000	$'000	%	$'000	$'000	%	$'000	$'000	%	$'000	$'000	$'000	$'000	$'000
System Access		192			421			561		298	126		303			581	312	318	324	330
System Renewal		645			482			623		1466	512		2116			1895	2528	2283	2339	2562
System Service		42			512			395		1015	141		51			51	52	53	54	55
General Plant		238			387			131		621	55		626			652	365	658	586	299
Total		1117			1802			1710		3400	833		3096			3180	3256	3312	3303	3246
System O&M		2053			2169			2389		2298	2482		2517			2651	2645	2711	2856	2848

Explanatory Notes on Variances

Notes on shifts in forecast vs. historical budgets by category

Not applicable- no previous DSP filed

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

Not applicable- no previous DSP filed – 2016 actual as of September 30

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

Not applicable- no previous DSP filed.

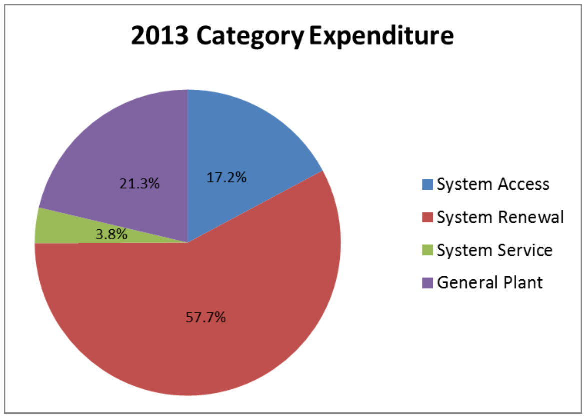
Table 45 – Capital Expenditure Summary

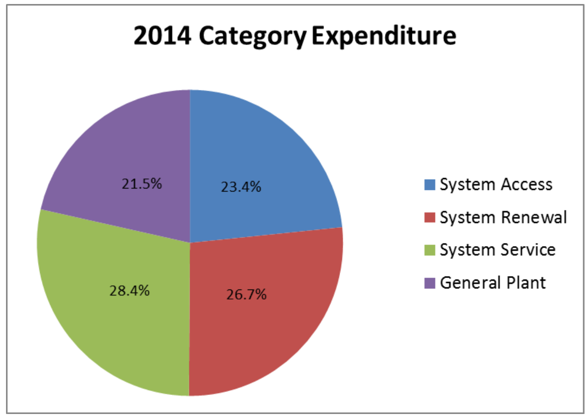
5.4.5 Justifying Capital Expenditures

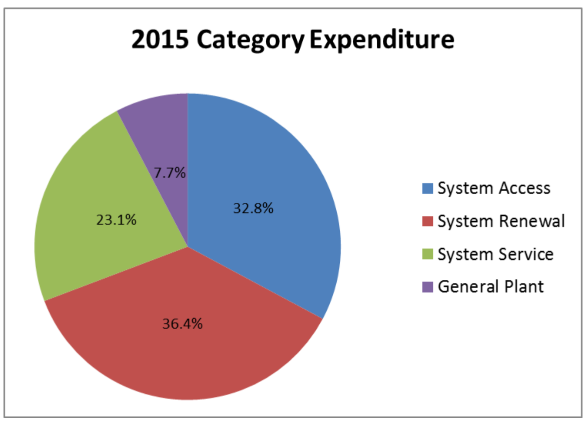
5.4.5.1 Overall Plan

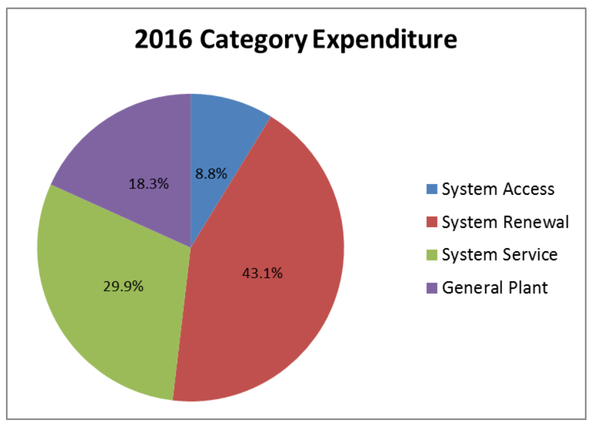
a. Comparative expenditures by category 2013 – 2017

The comparative expenditures by category over the historical period are shown in Table 45 in section 5.4.4 and in the following charts as percentages. Historical prior plan data has not been provided since a DSP has not previously been filed with the Board









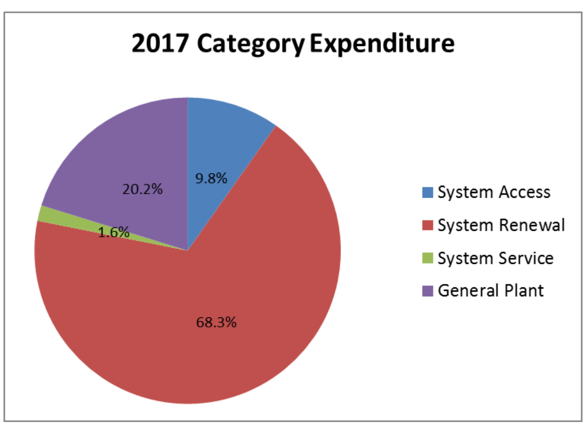


Figure 18 – 2013 – 2017 Capital Expenditure Charts

Historical spending and variance explanation by category is given below

System Access

CPC's System Access investments are driven by others. CPC is obligated to connect new load and new renewable generation. CPC uses an economic evaluation methodology prescribed in the DSC to determine the level, if any, of capital contributions for each project with such levels incorporated into the annual capital budget. The scheduling of investments needs is usually coordinated to meet the needs of third parties.

CPC is required to install metering equipment and provide access to poles for 3rd party attachments as per its mandated service obligation.

CPC is also required to respond to the road authorities by obligations under the *Public Service Works on Highways Act.* The Act prescribes a formula for the apportionment of costs that allows for the road authority to contribute 50% of the "cost of labour and labour saving devices" towards the relocation costs. This formula was used to apportion costs for road authority projects requiring the relocation of CPC plant.
.

The level of system access expenditures in each of 2013 to 2017 historical years has varied between $192k and $561k.

- 2013 actuals (CGAAP) were $192,101, net of capital contributions of $323,111. The majority of budget expense was for Smart Meter expenditures.
- 2014 actuals (CGAAP) were $420,523, net of capital contributions of $351,231. The increase from 2013 of $228,422 was primarily due to smart meter expenditures and an increase in road authority work.
- 2015 actuals (IFRS) were $560,955, net of capital contributions of $745,573. The increase from 2014 of $140,432 was primarily due to smart meter expenditures and a substantial increase in customer initiated projects (Bell fibre install on CPC poles).
- 2016 budget (IFRS) is $298,010 net of capital contributions of $1,761,106. The decrease from 2015 of $263,000 is due to a decrease in smart meter expenditures and less road authority work. Customer initiated project spending (Bell fibre install on CPC poles) continued to be high offset by contributed capital.
- 2017 budget (IFRS) is $303,033, net of capital contributions of $449,875. Less spending on customer initiated projects is expected. Overall spending expected to be similar to 2016.

Key material project multiyear spending is shown in the table below:

	2013	2014	2015	2016	2017
Meters	$ 18,783	$ 22,506	$ 1,384	$ -	$ -
Smart Meters	$ 172,774	$ 213,186	$ 263,273	$ 134,378	$ 139,533
Road Authority projects	$ 13,819	$ 163,369	$ 276,219	$ -	$ 138,375
Customer initiated projects	$ 177,228	$ 224,005	$ 634,745	$ 1,808,703	$ 350,000
Misc. Contributed Capital	-$ 323,111	-$ 351,231	-$ 745,573	-$ 1,761,106	-$ 449,875
Services	$ 132,608	$ 148,688	$ 130,906	$ 116,035	$ 125,000
Total	$ 192,101	$ 420,523	$ 560,954	$ 298,010	$ 303,033

Table 46 – Historical spending - Key System Access Projects

System Renewal

System renewal is a mix of discretionary (planned end of life replacement) and non-discretionary (emergency replacement) investments. Discretionary investments are identified in the Asset Management Plan, prioritized and scheduled.

The level of system renewal expenditures in each of 2013 to 2017 historical years has varied between $0.5Mand $2.5M.

- 2013 actuals (CGAAP) were $645,007.
- 2014 actuals (CGAAP) were $481,925. The decrease from 2013 of $163,082 was primarily due to reduced pole replacement spending and spare transformers capitalization.
- 2015 actuals (IFRS) were $622,551. The increase from 2014 of $140,626 was primarily due to increased number of rebuild projects.
- 2016 budget (IFRS) is $1,466,000. The increase from 2015 of $843,000 is primarily due to increased focus on pole and underground cable replacement programs.
- 2017 budget (IFRS) is $2,475,000. The increase from 2016 of $1,009,000 is primarily due to ramping up of the pole replacement programs to be able to replace approximately 85% of poor and very poor poles during the period of the DSP. Resources have been directed to achieving this target.

Key material project multiyear spending is shown in the table below:

	2013	2014	2015	2016	2017
Pole Replacement program (unplanned and planned)	$ 311,542	$ 222,714	$ -	$ 356,897	$ -
Planned pole replacement program	$ -	$ -	$ -	$ -	$ 300,000
Unplanned Pole Replacements	$ -	$ -	$ -	$ -	$ 100,000
Spare parts - Transformers	$ 59,395	$ 10,110	$ 67,668	$ -	$ -
Spare Parts - Meters	$ -	$ 1,897	$ -	$ -	$ -
St. Paul Street rebuild	$ -	$ -	$ -	$ -	$ -
Simcoe rebuild	$ 131,969	$ -	$ -	$ -	$ -
Hurontario Street South rebuild	$ 61,908	$ 17,184	$ 65,472	$ -	$ -
Ronell Crescent rebuild	$ 80,193	$ -	$ -	$ -	$ -
MS1 to Highway 26 (Stayner Part 1)	$ -	$ 80,494	$ -	$ -	$ -
Griffin Road - UG rebuild	$ -	$ 397	$ 3,456	$ 74,093	$ -
Seventh Street - UG rebuild	$ -	$ 44,051	$ -	$ -	$ -
Gibbard Cres North & South -UG rebuild	$ -	$ 10,871	$ 7,416	$ 268,434	$ -
2nd St - Simcoe St (back lanes)	$ -	$ 19,372	$ 55,046	$ -	$ -
Spruce St - 7th St to Griffin Rd	$ -	$ 51,031	$ -	$ -	$ -
Brock Crescent Pole Trans Replacement	$ -	$ 23,804	$ -	$ -	$ 210,000
Osler Crescent	$ -	$ -	$ 2,274	$ 59,517	$ -
Tenth St – Spruce to Walnut	$ -	$ -	$ 126,525	$ -	$ -
Mary St & County Rd. #9	$ -	$ -	$ 8,259	$ 123,000	$ -
Campbell St - Telfer St. To Hurontario St	$ -	$ -	$ 33,212	$ 116,850	$ -
Oak Street - Sixth to Cambell	$ -	$ -	$ 14,891	$ 188,283	$ -
Stayner Feeder rebuild	$ -	$ -	$ -	$ 145,848	$ -
Princton Shores Blvd	$ -	$ -	$ -	$ 133,455	$ -
Misc. rebuilds	$ -	$ -	$ 238,332	$ -	$ -
Leslie Drive Pole Trans Replacement	$ -	$ -	$ -	$ -	$ 168,000
Lockhart Road Underground	$ -	$ -	$ -	$ -	$ 168,000
Maple Street Pole Trans Replacement	$ -	$ -	$ -	$ -	$ 42,000
Riverside Crescent, Thornbury Pole Trans Replacement	$ -	$ -	$ -	$ -	$ 126,000
Heritage Drive 4.16kV Pole Line Rebuild	$ -	$ -	$ -	$ -	$ 264,500
Back Lane/Williams St Rebuild (44kV)	$ -	$ -	$ -	$ -	$ 115,000
Walnut Street Trail 44kV/4 Poles	$ -	$ -	$ -	$ -	$ 92,000
Patterson St - Collins to Lorne & out to Hume (44kV)	$ -	$ -	$ -	$ -	$ 210,000
Katherine - Collins to Lorne & across Lorne to Minnesota (44kV)	$ -	$ -	$ -	$ -	$ 200,000
MS2 - Collingwood U/G Feeder Egress	$ -	$ -	$ -	$ -	$ 120,000
Total	$ 645,007	$ 481,925	$ 622,551	$ 1,466,377	$ 2,115,500

Table 47 – Historical spending - Key System Renewal Projects

System Service

System Service investments are discretionary investments to provide for consistent service delivery and to meet operational objectives. These investments are required to support the expansion, operation and reliability of the distribution system.

The level of system service expenditures in each of 2013 to 2017 historical years has varied between $0.04M and $1.0M.

- 2013 actuals (CGAAP) were $41,961.
- 2014 actuals (CGAAP) were $511,718. The increase from 2013 of $469,757 was primarily due to the rebuild of existing 4 & 44KV pole line to accommodate a new 44kV feeder for 44KV from Hydro One. Existing 44KV M1 feeder from Meaford TS was at capacity. Replaced with new M7 feeder from Stayner TS.
- 2015 actuals (IFRS) were $395,354. The decrease from 2014 of $116,364 was primarily due to completion of the new 44kV M7 feeder circuit from Stayner TS.
- 2016 budget (IFRS) is $1,014,750. The increase from 2015 of $619,396 is primarily due to work to accommodate new capacity from upgraded HONI station in the Creemore service area.
- 2017 budget (IFRS) is $50,135. Spending has decreased from 2016 levels to lower historical values with the completion of the HONI station upgrade in the Creemore service area.

Key material project multiyear spending is shown in the table below:

	2013	2014	2015	2016	2017
Buildings and Fixtures - Other	$ -	$ -	$ 2,300	$ -	$ -
Dist Stn Equipment <50kV	$ -	$ 106,412	$ -	$ -	$ -
SCADA	$ 13,411	$ 13,696	$ 35,068	$ 49,200	$ 51,087
HONI Creemore MS upgrade	$ -	$ -	$ 122,895	$ 861,000	$ -
10th line - Poplar to Mountain Road	$ 28,550	$ 379,609	$ -	$ -	$ -
Mountain Rd - 10th to Cambridge	$ -	$ 12,001	$ 235,091	$ 104,550	$ -
Total	$ 41,961	$ 511,718	$ 395,354	$ 1,014,750	$ 51,087

Table 48 – Historical spending - Key System Service Projects

General Plant

General Plant investments are discretionary investments, not part of its distribution system (e.g. fleet, tools, land, etc.). Investments in this category are driven by operational and business needs to achieve a safe work place, enhance employee work environments and satisfaction, increase efficiencies and productivity, and enhance customer service and value.

The level of general plant expenditures in each of 2013 to 2017 historical years has varied between $0.1M and $3.6M.

- 2013 actuals (CGAAP) were $237,696.
- 2014 actuals (CGAAP) were $387,068. The increase from 2013 of $149,372 was primarily due to increased transportation equipment spending and general spending increases in other general plant categories.
- 2015 actuals (IFRS) were $131,087. The decrease from 2014 of $255,981 was primarily due to significant reduced spending in the transportation equipment category.

- 2016 budget (IFRS) is $621,150. The increase from 2015 of $490,063 is primarily due to the procurement of a large fleet vehicle to replace an existing vehicle that was at end of life.
- 2017 budget (IFRS) is $626,334. Spending is expected to slightly higher than 2016 with the continued focus on fleet refurbishment

Key material investment multiyear spending is shown in the table below:

	2013	2014	2015	2016	2017
Office Furniture	$ 18,040	$ 9,437	$ 2,282	$ 61,500	$ 20,000
Computer Equipment	$ 4,951	$ 3,654	$ 53,754	$ 36,900	$ 50,000
Computer Software	$ 37,001	$ 51,314	$ 12,521	$ 92,250	$ 50,000
Transportation Equipment	$ 164,943	$ 262,918	$ 39,115	$ 399,750	$ 475,000
Stores Equipment	$ 5,482	$ 6,774	$ 7,818	$ -	$ -
Measurement & Testing Equipment	$ -	$ 27,238	$ 3,182	$ 30,750	$ 31,334
Power Operated Equipment	$ -	$ 4,867	$ 7,525	$ -	$ -
Communication Equipment	$ 7,279	$ 20,866	$ 4,890	$ -	$ -
Total	$ 237,696	$ 387,068	$ 131,087	$ 621,150	$ 626,334

Table 49 – Historical spending - Key General Plant investments

b. Impact of system investment on O&M costs 2018 – 2022

CPC's operations and maintenance strategy is, to the extent possible, to minimize reactive and emergency-type work through efficient operations and an effective planned maintenance program, including predictive and preventative actions. CPC's customer responsiveness and system reliability are monitored continually to ensure that its maintenance strategy is effective. This effort is coordinated with CPC's capital project work so that where maintenance programs have identified matters which require capital investments, CPC may adjust its capital spending priorities to address those matters.

- Predictive Maintenance - Predictive maintenance activities involve the testing of elements of the distribution system. These activities include infrared thermography testing, transformer oil analysis, planned visual inspections and pole testing. These evaluation tools are all administered using a grid system with appropriate frequency levels. Any identified deficiencies are prioritized and addressed within a suitable time frame.
- Preventative Maintenance - Preventative maintenance activities include inspection, servicing and repair of network components. This includes overhead and pad-mounted switch maintenance. Also included are regular inspection and repair of substation components and ancillary equipment. The work is performed using a combination of time and condition based methodologies.
- Emergency Maintenance - This item includes unexpected system repairs to the electrical system that must be addressed immediately. The costs include those related to repairs caused by storm damage, emergency tree trimming and on-call premiums. CPC constantly evaluates its maintenance data to adjust predictive and preventative actions. The ultimate objective is to reduce this emergency maintenance. An answering service company has been contracted to contact "on call" lineperson and supervisory staff in the event of service problems outside of normal business hours.
- Service Work - The majority of costs related to this work pertain to service upgrades requested by customers, and requests to provide safety coverage for work (overhead line cover ups). This includes service disconnections and reconnections by CPC for all service classes; assisting pre-approved contractors; the making of final connections after Electrical Safety Authority ("ESA") inspection for service upgrades; and changes of service locations.

- Network Control Operations – CPC maintains a Supervisory Control and Data Acquisition (“SCADA”) system.
- Metering - The metering department is responsible for the installation, testing, and commissioning of new and existing simple and complex metering installations. Testing of complex metering installations ensures the accuracy of the installation and verifies meter multipliers for billing purposes. Revenue Protection is another key activity performed by Metering, by proactively investigating potential diversion and theft of power.
- Substation Services - Substation services activities address the maintenance of all equipment at CPC’s 14 substations. This includes both labour costs and non-capital material spending to support both scheduled and emergency maintenance events. As with the maintenance activities, substation maintenance strategy focuses on minimizing, to the extent possible, emergency-type work by improving the effectiveness of CPC’s planned maintenance program (including predictive and preventative actions) for its substations.
- Operations Area - The Operations area coordinates drafting and design services for capital projects and provides distribution system asset information to many departments within CPC. Engineering costs were allocated to operations, maintenance, capital, and Third Party receivable accounts based on total labour, truck and material costs. A standard overhead percentage is set at the beginning of the year for all jobs, and adjusted to actual at year end.
- Stores/Warehouse - The Stores area is accountable for managing the procurement, control, and movement of materials within CPC’s service centre. This includes monitoring inventory levels, issuing material receipts, material issues, and material returns as required. The cost of the stores department is allocated to all departmental, capital and Third Party receivable accounts as an overhead cost based on direct material costs. A standard overhead percentage is set at the beginning of the year and adjusted to actual at year end.
- Garage/Transportation Fleet - The Garage and Transportation Fleet area has as one of its objectives keeping maintenance schedules to ensure vehicle reliability and safety, and the minimization of vehicle down time. Vehicle costs are allocated to operations, maintenance, capital and Third Party receivable accounts based on number of hours used. A standard “cost per hour” is set for all vehicles within the fleet (one rate for passenger vehicles and pickup and another rate for bucket trucks and work platforms).

System investments will result in:

- the addition of incremental plant (e.g. new MS, poles, switchgear, transformers, etc.);
- the relocation/replacement of existing plant (e.g. road widenings);
- the replacement of end of life plant with new plant (e.g. cables, poles, transformers, etc.)
- new/replacement system support expenditures (e.g. fleet, software, etc.)

In general, incremental plant additions (e.g. new MS c/w transformer, switchgear, land, etc.) will be integrated into the Asset Management system and will require incremental resources for ongoing O&M purposes. This is expected to put upward pressure on O&M costs. Forecast O&M costs for the 2018 – 2022 period are:

2018	2019	2020	2021	2022
$2,651,000	$2,645,000	$2,711,000	$2,856,000	$2,848,000

Table 50 – 2018 – 2022 O&M projections

Relocation/replacement of existing plant normally results in an asset being replaced with a similar one, so there would be little or no change to resources for ongoing O&M purposes (i.e. inspections still need to be carried out on a periodic basis as required per the Distribution System Code). There may be some slight life advantages when a working older piece of equipment is replaced with a newer one that would impact on O&M repair related charges. Overall the plan system investments in this category are expected to put neutral pressure on O&M costs.

Replacement of end of life plant with new plant will still require the allocation of resources for ongoing O&M purposes. Repair would be the most significant O&M activity impacted by new plant. Certain assets, such as poles, offer few opportunities for repair related activities and generally require replacement when deemed at end of normal life or critically damaged. Other assets such as direct buried cable offer opportunities for repair related activities (e.g. splices) up to a point where further repairs are not warranted due to end of life conditions. In a few areas cable faults will not be repaired due to cable end of life. When faulted, the faulted cable section will be replaced, normally a section between two distribution transformers. For planned cable replacement in a subdivision, new primary cable installed in duct replaces direct buried primary cable and is expected to provide higher reliability and life. This will shift response activity for a cable failure from repair (O&M) to replacement (Capital). If assets approaching end of life are replaced at a rate that maintains equipment class average condition then one would expect little or no change to O&M costs under no growth scenarios but would still see upward O&M cost pressure on positive growth scenarios (more cumulative assets to maintain each year). Replacement rates that improve equipment class average condition could result in lowering certain maintenance activities costs (e.g. pole testing, reactive repairs, etc.). Overall this is expected to put downward pressure on O&M repair related costs.

Locate expenditures have increased significantly due to recent legislative requirements for expanded need for locates and significant local 3rd party attachment work.

System support expenditures (e.g. GIS, SmartMAP) are expected to provide a better overall understanding of CPC's assets that will lead to more efficient and optimized design, maintenance and investment activities going forward. Inspection, maintenance and testing data will be input into the GIS as attribute information for each piece of plan. Increased and accurate operating data will be collected through SmartMAP and be made available for engineering analysis and service quality reporting. Improved asset information will allow existing resources to partially compensate for growth related increases in O&M activities. Fleet replacement expenditures will result in reduced O&M for new units however this will be offset by increasing O&M of remaining units as they get older.

In summary, the system investments will result in some upward growth related and support related O&M pressures, downward repair related O&M pressures. Overall the system investments are not expected to have a significant impact on total O&M costs in the forecast period.

Item	Growth impact on O&M	Relocate impact on O&M	Replace impact on O&M	Support impact on O&M
Poles	increase	neutral	neutral	increase
Cables	increase	N/A	decrease (repairs only)	neutral
UG Transformers	increase	N/A	neutral	neutral
UG Switchgear	increase	N/A	neutral	neutral
OH Transformers	increase	neutral	neutral	neutral
MS Transformers	increase	N/A	decrease (repairs only)	decrease
MS Circuit breakers	increase	N/A	decrease (repairs only)	decrease
Meters	increase	N/A	neutral	increase
Fleet	increase	N/A	neutral	neutral

Table 51 – O&M impacts for significant assets

CPC's forecast O&M increases during the plan period are predicted to be approximately 3% per year.

c. Investment drivers

During the 2018 – 2022 period, CPC has 2 key drivers of its capital investment:

1. obligation to connect a customer in accordance with Section 28 of the Electricity Act, 1998, Section 7 of CPC's Electricity Distribution Licence and the Distribution System Code.
2. planned system renewal spending to proactively replace plant at end of life in order to meet CPC's commitment to maintain a safe and reliable supply of electricity to its customers.

The specific investments drivers for each category are described below:

<u>System Access</u>

- Customer service requests - continued development of the Towns of Collingwood, Stayner, Thornbury and Creemore requiring new customer connections (site redevelopment; subdivisions)

In summary, forecast employment and population growth in the Towns of Collingwood, Stayner, Thornbury and Creemore, will continue to focus 2018 -2022 System Access needs on new subdivision connections, connection upgrades due to site redevelopment, and plant relocation.

<u>System Renewal</u>

- Failure Risk - multiyear planned pole replacement programs that address assets in "very poor" and "poor" condition. Historical trend has seen decreasing investments due to resource reallocation to mandatory System Access investments related to third party plant relocations. Forecast investments will increase as resources become available.
- High Performance Risks - overhead line rebuilds. Historical investments have been based on sections of line that require complete rebuild (poles, conductors, insulators, etc.) as opposed to dispersed pole replacement works. Forecast investments will continue to target specific sections of line requiring complete rebuild.
- Emergency needs - emergency reactive replacement of distribution system assets (poles, transformers, switches, switchgear, cable, conductor, insulators, guys, anchors, etc.) due to unanticipated failure, storms, motor vehicle accidents, vandalism, etc.

In summary, system renewal spending will focus more proactively on planned proactive pole replacement programs at higher levels than seen in the historical period except for 2017. Specific high performance Risk areas will be prioritized during the 2018 – 2022 period at increased levels that manage Risk of equipment failure while mitigating rate impacts to customers.

<u>System Service</u>

- System operational objectives – investments to maintain system reliability and efficiency of distribution stations. Historical investments needs related to system supervisory have been relatively consistent and low. Forecast investment needs related to SCADA and SmartMAP modifications are expected to be of similar magnitude.

In summary, system service spending will continue to focus on maintaining operational performance.

General Plant

- System Maintenance support – replacement of rolling stock; tools. Historical investments have resulted in specific rolling stock and tool replacement as required. Replacement of major fleet units tends to create cost spikes in a particular investment year when compared to the replacement costs of small fleet units. Forecast investments include the replacement of major fleet units in 2017 and 2018.
- Business Operations efficiency – ongoing improvements to CIS, GIS and other computer systems to provide more accurate and timely data for investment and operational purposes
- Non-system Physical plant – office equipment, tools, etc. Historical investments have been relatively steady during the historical period

In summary, general plant spending will continue to focus on ensuring fleet asset performance meets CPC's operational and reliability needs, information systems capable of providing enhanced functionality to day to day operations and facilities that meet current and future needs of the system.

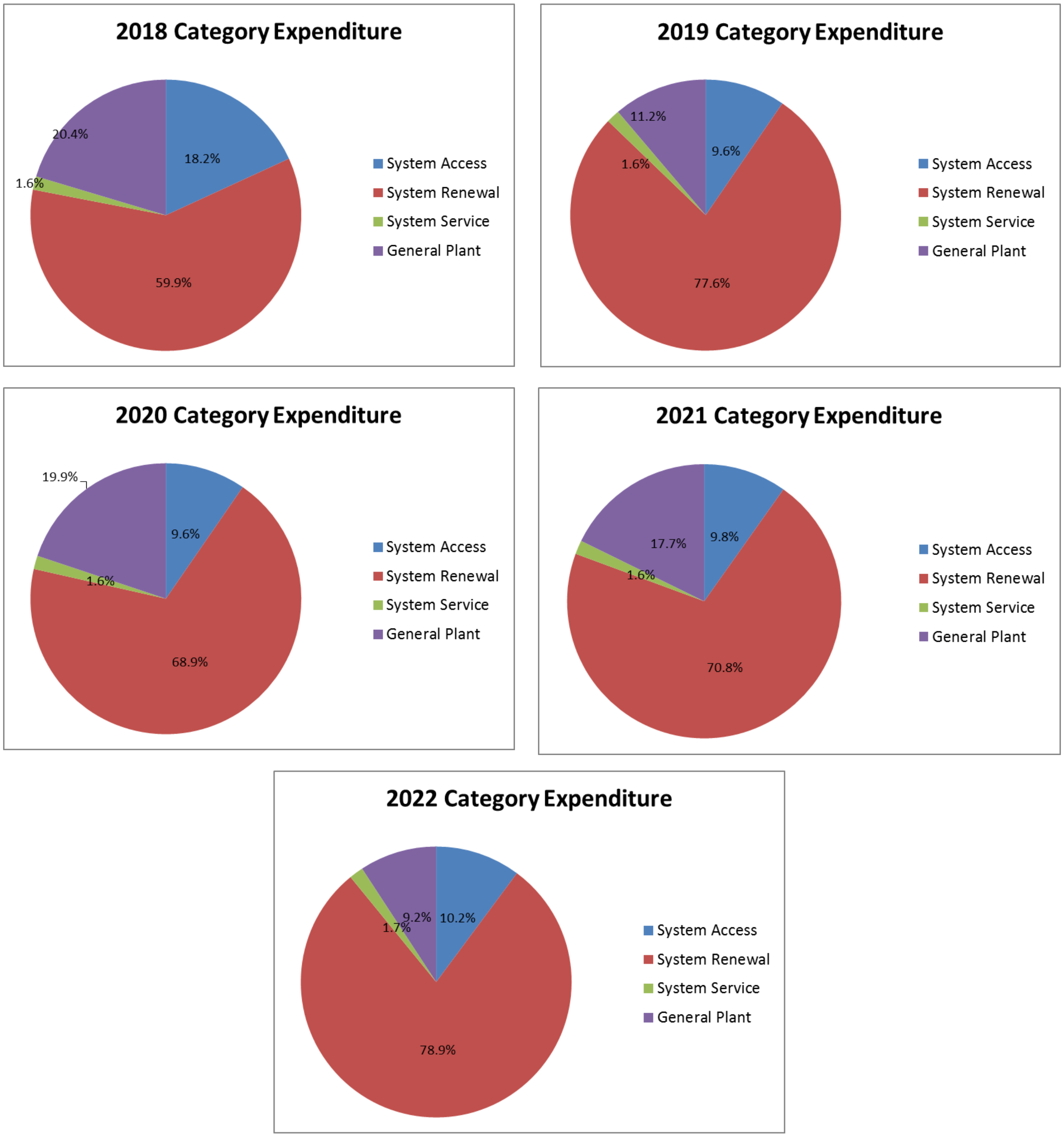


Figure 16 – 2018 – 2022 Capital Expenditure Charts

d. CPC capability assessment

There is sufficient capacity on the CPC distribution system to connect foreseeable REG needs over the investment period, with the exception of two 4.16kV feeders that are at capacity. It is not a significant driver for any of the four category expenditures.

5.4.5.2 Material Investments

This section includes the material justification for projects by year from 2018 to 2022.

Chapter 2 of the Filing Requirements for Transmission and Distribution Applications issued by the Board July 14, 2016 states the relevant default materiality threshold as:

"$50,000 for a distributor with a distribution revenue requirement less than or equal to $10 million"

The 2018 CPC Distribution revenue requirement is $7,000,000, and as such the materiality threshold is calculated as being $35,000. CPC follows the OEB's default materiality threshold and provides justification for capital expenditures of $50,000 or higher.

All material projects have the following information provided:

A. General Information on the Project/Activity
B. Evaluation criteria for each project/activity
C. Category-specific information and analysis for each project/activity

A. <u>General Information on the Project/Activity</u>

1. Total capital and where applicable, (non-capitalized) O&M costs proposed for recovery in rates
2. Related customer attachments and load, as applicable
3. Start date, in-service date and expenditure timing over the planning horizon (2018 – 2022)
4. The Risks to the completion of the project or activity as planned and the manner in which such Risks will be mitigated
5. Comparative information on expenditures for equivalent projects/activities over the historical period, where available
6. Information on total capital and O&M costs associated with REG investment, if any, included in a project/activity; and a description of how the REG investment is expected to improve the system's ability to accommodate the connection of REG facilities

B. <u>Evaluation criteria for each project/activity</u>

Material investments are evaluated based on key regulatory outcomes as indicated below:

1. Efficiency, customer value and reliability
2. Safety
3. Cyber-security, privacy
4. Co-ordination, interoperability
5. Economic Development
6. Environmental benefits

C. <u>Category-specific information and analysis for each project/activity</u>

1. System Access
2. System Renewal
3. System Service
4. General Plant

2018 - 2022 Material Projects

Collus PowerStream Capital Project

2018 - 2022

Project Name:	**Annual Customer Additions – multiyear expenditure**
Project #:	
Investment Category:	**System Access**
Investment Type:	Non-discretionary
Service Area:	Collingwood

Start Date:	**January 1, 2018**	**In Service Date:**	**January – December 31, 2022**
Net Capital Cost: (Gross – Contributed + OM&A)	**See below**	**Gross Capital Cost:**	**$TBD**
		Contributed Capital:	**$TBD**
		OM&A Costs:	**$0**

Expenditure Timing:	**Q1**	**Q2**	**Q3**	**Q4**
	$TBD	**$TBD**	**$TBD**	**$TBD**

A. General Information:

New customer additions – annual program.

Year	Amount
2018	$127,375
2019	$129,795
2020	$132,261
2021	$134,774
2022	$137,335

Risks to Completion and Risk Mitigation: Timing subject to Customer needs. Material and resources available.

Comparative Information on Equivalent Historical Projects (if any): This is an annual non-discretionary program.

Renewable Energy Generation linkage: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver**: Provide connection supply to new services
	Priority # N/A – Regulatory requirement and non-discretionary project, driven by residential and commercial development. Connection coordinated with customer requirements.
	Investment effectiveness: Ensure compliance with Section 28 of the Electricity Act and customer satisfaction. Customers provide capital contribution amounts as per DSC.
Safety	Connection constructed according to Reg. 22/04 standards

Cyber Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Economic Development	Connection of new services supports municipal economic growth
Environmental benefits	N/A

C. Category-specific requirements: System Access	
Projects/activities in this category are driven by statutory, regulatory or other obligations on the part of the distributor to provide customers with access to their distribution system.	
Factors affecting the Timing/Priority of implementing the project	Non-discretionary; project timing coordinated with customer need to connect
Factors relating to Customer Preferences or input from customers and other third parties	Connection date subject to customer schedule.
Factors affecting the final cost of the project	Final cost is based upon actual number of residential services to be connected in 2018 through 2022.
How controllable costs have been minimized	Connection work coordinated with customer schedule; final connection costs to be based on standardized materials, unit rate construction contracts, and appropriate equipment sizing.
Identify if other planning objectives (System Renewal, System Service, General Plant) are met by the project or have intentionally been combined into the project and if so, which objectives and why	-n/a
Project Options Considered	-n/a
Summary of business case analysis (if applicable)	-project subject to economic evaluation per DSC
Results of Final Economic Valuation (if applicable)	-n/a
System Impacts (Nature, Magnitude and Costs)	-n/a
Other related information	-n/a

Collus PowerStream Capital Project

2018 - 2022

<table>
<tr><td>Project Name:</td><td colspan="4">Smart Meter Expenditures – multiyear expenditure</td></tr>
<tr><td>Project #:</td><td colspan="4"></td></tr>
<tr><td>Investment Category:</td><td colspan="4">System Access</td></tr>
<tr><td>Investment Type:</td><td colspan="4">Non-discretionary</td></tr>
<tr><td>Service Area:</td><td colspan="4">Collingwood</td></tr>
<tr><td colspan="2">Start Date: January 1, 2018</td><td colspan="3">In Service Date: January – December 31, 2022</td></tr>
<tr><td colspan="2" rowspan="3">Net Capital Cost: See Below
(Gross – Contributed + OM&A)</td><td>Gross Capital Cost:</td><td colspan="2">See below</td></tr>
<tr><td>Contributed Capital:</td><td colspan="2">$0</td></tr>
<tr><td>OM&A Costs:</td><td colspan="2">$0</td></tr>
<tr><td>Expenditure Timing:</td><td>Q1
$TBD</td><td>Q2
$TBD</td><td>Q3
$TBD</td><td>Q4
$TBD</td></tr>
</table>

A. General Information:

Smart Meter capitalization.

Year	Amount
2018	$139,533
2019	$142,184
2020	$144,885
2021	$147,638
2022	$150,443

Risks to Completion and Risk Mitigation: Timing subject to needs. Material and resources available.

Comparative Information on Equivalent Historical Projects (if any): This is an annual non-discretionary program.

Renewable Energy Generation linkage: N/A

B. Investment Evaluation Criteria

<table>
<tr><td rowspan="3">Efficiency, Customer Value, Reliability</td><td>Main Driver: Mandated service obligation.</td></tr>
<tr><td>Priority # N/A – Regulatory requirement and non-discretionary project, driven by residential and commercial meter needs.</td></tr>
<tr><td>Investment effectiveness: N/A</td></tr>
<tr><td>Safety</td><td>N/A</td></tr>
<tr><td>Cyber Security, Privacy</td><td>N/A</td></tr>
<tr><td>Co-ordination, Interoperability</td><td>N/A</td></tr>
<tr><td>Economic</td><td></td></tr>
</table>

Development	N/A
Environmental benefits	N/A
C. Category-specific requirements: System Access	
Projects/activities in this category are driven by statutory, regulatory or other obligations on the part of the distributor to provide customers with access to their distribution system.	
Factors affecting the Timing/Priority of implementing the project	Meter stock subject to forecast needs
Factors relating to Customer Preferences or input from customers and other third parties	N/A
Factors affecting the final cost of the project	N/A
How controllable costs have been minimized	N/A.
Identify if other planning objectives (System Renewal, System Service, General Plant) are met by the project or have intentionally been combined into the project and if so, which objectives and why	N/A.
Project Options Considered	N/A.
Summary of business case analysis (if applicable)	N/A.
Results of Final Economic Valuation (if applicable)	N/A.
System Impacts (Nature, Magnitude and Costs)	N/A.
Other related information	N/A.

Collus PowerStream Capital Project

2018 - 2022

Project Name:	**Road relocation work - multiyear program**
Project #:	
Investment Category:	**System Access**
Investment Type:	Non-discretionary
Service Area:	Collingwood

Start Date:	**January 1, 2018**	**In Service Date:**	**December 31, 2022**
Net Capital Cost: (Gross – Contributed + OM&A)	**See below**	**Gross Capital Cost:**	**See below**
		Contributed Capital:	**$TBD**
		OM&A Costs:	**$0**

Expenditure Timing:	**Q1**	**Q2**	**Q3**	**Q4**
	$TBD	**$TBD**	**$TBD**	**$TBS**

A. General Information:

Construction costs for pole relocation due to County/ Town road rebuilding projects.

Year	Amount
2018	$141,005
2019	$143,684
2020	$146,414
2021	$149,195
2022	$152,030

Risks to Completion and Risk Mitigation: Overall project timing subject to County/Town schedule.

Comparative Information on Equivalent Historical Projects (if any): This is a non-discretionary program requiring plant relocation due to road rebuilding. Similar to previous pole relocation projects.

Renewable Energy Generation linkage: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver**: to accommodate County/Town road rebuilding needs
	Priority # N/A – Regulatory requirement and non-discretionary project, driven by third party needs. Plant relocation coordinated with Simcoe County, Town of Collingwood.
	Investment effectiveness: Complies with mandated service requirements of DSC. County/Town provides capital contribution amounts as per Public Service Works on Highways Act. County/Town also pay for incremental non like-for-like enhancements
Safety	Relocated plant to be installed in accordance with CSA construction standards and in compliance with ESA Reg. 22/04
Cyber Security,	N/A

Privacy	
Co-ordination, Interoperability	This work will be coordinated with County/Town schedules and plans.
Economic Development	N/A
Environmental benefits	N/A

C. Category-specific requirements: System Access	
Projects/activities in this category are driven by statutory, regulatory or other obligations on the part of the distributor to provide customers with access to their distribution system.	
Factors affecting the Timing/Priority of implementing the project	Non-discretionary; project design parameters and timing coordinated with County/Town schedule
Factors relating to Customer Preferences or input from customers and other third parties	Pole relocation details subject to County/Town consultation.
Factors affecting the final cost of the project	Project cost determined by County/Town road design issues affecting pole relocation and construction grade required to accommodate safe and reliable installation.
How controllable costs have been minimized	Design to meet current CSA standards and to incorporate sufficient load carrying strength to minimize guying needs and property acquisition. Construction work coordinated with County/Town schedule; County/Town provide capital contribution amounts as per Public Service Works on Highways Act. County/Town to pay incremental cost for non like-for-like relocation conditions (i.e. decorative concrete vs standard wood pole)
Identify if other planning objectives (System Renewal, System Service, General Plant) are met by the project or have intentionally been combined into the project and if so, which objectives and why	Depending on the specific project, there may be some indirect system renewal benefit through replacement of old poles with new plant
Project Options Considered	-n/a
Summary of business case analysis (if applicable)	-n/a
Results of Final Economic Valuation (if applicable)	-n/a
System Impacts (Nature, Magnitude and Costs)	-n/a
Other related information	-n/a

Collus PowerStream Capital Project

2018

Project Name:	**Seventh Street and Eighth Street road relocation work**			
Project #:				
Investment Category:	**System Access**			
Investment Type:	Non-discretionary			
Service Area:	Collingwood			
Start Date:	**January 1, 2018**	**In Service Date:**	**December 31, 2018**	
Net Capital Cost: **$183,420** (Gross – Contributed + OM&A)		**Gross Capital Cost:**	**$275,130**	
		Contributed Capital:	**$91,710**	
		OM&A Costs:	**$0**	

Expenditure Timing:	**Q1**	**Q2**	**Q3**	**Q4**
	$0	**$175,130**	**$100,000**	**$0**

A. General Information:

Construction costs for pole relocation due to County/ Town road rebuilding projects.

Project	Poles	Cost
Seventh Street - Hurontario St to Birch St	15	$ 152,850
Eighth Street - Hurontario St to Birch St	12	$ 122,280
Total	**27**	**$275,130**

Risks to Completion and Risk Mitigation: Overall project timing subject to County/Town schedule.

Comparative Information on Equivalent Historical Projects (if any): This is a non-discretionary program requiring plant relocation due to road rebuilding. Similar to previous pole relocation projects.

Renewable Energy Generation linkage: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver**: to accommodate County/Town road rebuilding needs
	Priority # N/A – Regulatory requirement and non-discretionary project, driven by third party needs. Plant relocation coordinated with Simcoe County, Town of Collingwood.
	Investment effectiveness: Complies with mandated service requirements of DSC. County/Town provides capital contribution amounts as per Public Service Works on Highways Act. County/Town also pay for incremental non like-for-like enhancements
Safety	Relocated plant to be installed in accordance with CSA construction standards and in compliance with ESA Reg. 22/04
Cyber Security, Privacy	N/A
Co-ordination,	This work will be coordinated with County/Town schedules and plans.

Interoperability	
Economic Development	N/A
Environmental benefits	N/A
C. Category-specific requirements: System Access	
Projects/activities in this category are driven by statutory, regulatory or other obligations on the part of the distributor to provide customers with access to their distribution system.	
Factors affecting the Timing/Priority of implementing the project	Non-discretionary; project design parameters and timing coordinated with County/Town schedule
Factors relating to Customer Preferences or input from customers and other third parties	Pole relocation details subject to County/Town consultation.
Factors affecting the final cost of the project	Project cost determined by County/Town road design issues affecting pole relocation and construction grade required to accommodate safe and reliable installation.
How controllable costs have been minimized	Design to meet current CSA standards and to incorporate sufficient load carrying strength to minimize guying needs and property acquisition. Construction work coordinated with County/Town schedule; County/Town provide capital contribution amounts as per Public Service Works on Highways Act. County/Town to pay incremental cost for non like-for-like relocation conditions (i.e. decorative concrete vs standard wood pole)
Identify if other planning objectives (System Renewal, System Service, General Plant) are met by the project or have intentionally been combined into the project and if so, which objectives and why	Depending on the specific project, there may be some indirect system renewal benefit through replacement of old poles with new plant
Project Options Considered	-n/a
Summary of business case analysis (if applicable)	-n/a
Results of Final Economic Valuation (if applicable)	-n/a
System Impacts (Nature, Magnitude and Costs)	-n/a
Other related information	-n/a

Collus PowerStream Capital Project

2018 - 2022

Project Name:	**Planned Pole Changes – multiyear program**				
Project #:					
Investment Category:	**System Renewal**				
Investment Type:	**Discretionary**				
Service Area:	**All CPC area**				
Start Date:	**January 1, 2018**		**In Service Date:**	**December 31, 2022**	
Net Capital Cost: $1,585,500			**Gross Capital Cost:**	**$1,585,500**	
			Contributed Capital:	**$0**	
			OM&A Costs:	**$0**	
Expenditure Timing:	**Q1 $TBD**	**Q2 $TBD**	**Q3 $TBD**	**Q4 $TBD**	

A. General Information:

This is an annual program that covers the planned replacement of individual poles when it has been determined that they have reached end-of-life. End-of-life is determined through the inspection process and CPC's asset management program. Multiyear program spending.

Year	Amount
2018	$305,700
2019	$311,400
2020	$317,100
2021	$322,800
2022	$328,500

Risks to Completion and Risk Mitigation: CPC material and resources available.
Comparative Information on Equivalent Historical Projects (if any): This is a discretionary annual program. Related spending in previous years. Multi-year program to replace up to 1300 poles in "very poor"/"poor" condition. Approximately 30 poles per year are addressed through this planned program.
Renewable Energy Generation linkage: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver:** This project is driven by the need to replace assets that have reached End-Of-Life status.
	Priority # 1 – Discretionary project
	Investment effectiveness: Plant is replaced like-for-like or upgraded to as per plans for the area.
Safety	Poles at End-Of-Life represents a safety hazard to staff and the public. EOL status generally implies that pole structural strength has decreased to levels below the minimum acceptable per CSA Standard for Overhead construction. Replacement of EOL plant restores the system to safe structural and operating condition
Cyber Security, Privacy	N/A

Co-ordination, Interoperability	N/A
Economic Development	N/A
Environmental benefits	N/A
C. Category-specific requirements: System Renewal	
Projects/activities in this category are driven by the relationship between the ability of an asset or asset system to continue to perform at an acceptable standard on a predictable basis on one hand and on the other, the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. "failure").	
Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure 1. Condition of Asset vs. Typical Life Cycle and Performance Record 2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure 3. Quantitative Customer Impacts (frequency or duration of interruptions and associated Risk level) 4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated Risk level) 5. Value of Customer Impact high, medium, low)	1. Asset at EOL have reached the end of their life cycle. Future satisfactory performance in doubt. 2. Varies – pole failure may involve an entire feeder depending on location and protective device activated (i.e. lateral fuse or circuit breaker, etc.) 3. Pole failure could result in major interruption of 6-8 hours. 4. Reduced outages will improve customer satisfaction. 5. Customer surveys show that reliability is ranked high in value to them
Factors that may affect the timing of the proposed project, including the rate at which assets are replaced over the forecast period (i.e. investment intensity), where applicable;	CPC has the resources and materials in order to ensure project completion on time. Locates required from others.
Consequences for system O&M costs, including the implications for system O&M of not implementing the project	N/A – EOL equipment may fail unexpectedly and result in higher replacement costs (overtime, etc.) and higher outage costs to customers due to extended duration of unplanned outage
Reliability and or safety factors	New poles will be installed per CSA and 22/04 standards
Analysis of Project Benefits and Costs with alternative timing, expenditure, mitigation comparisons	Value/Risk result: 6.9 – 5.98 N/A – deferral increases Risk of unexpected failure; other alternatives (i.e. undergrounding) more expensive.
Analysis of Project Benefits and Cost for extra cost "like for like". (System Access, System Service, General Plant benefit) (if applicable)	Pole class and loading design may be upgraded to coincide with plans for the area.
Other related information	Multi-year program to replace ~1300 poles in "very poor"/"poor" condition. Complements the Line Rebuild projects.

Collus PowerStream Capital Project

2018 - 2022

Project Name:	**Unplanned Pole Changes – multiyear program**		
Project #:			
Investment Category:	**System Renewal**		
Investment Type:	**Non-Discretionary**		
Service Area:	**Collingwood**		
Start Date:	**January 1, 2018**	**In Service Date:**	**December 31, 2018**
Net Capital Cost: $528,500		**Gross Capital Cost:**	**$528,500**
		Contributed Capital:	**$0**
		OM&A Costs:	**$0**

Expenditure Timing:	**Q1**	**Q2**	**Q3**	**Q4**
	$TBD	**$TBD**	**$TBD**	**$TBD**

A. General Information:

This is an annual program that covers the emergency replacement of poles when they fail. Poles may fail unexpectedly or be in imminent position to fail and are replaced reactively, as required, in order to maintain the system in its current working state. The failures are caused for numerous reasons including: foreign interference, such as car accidents; trees falling on the lines, major storms, and failure of the equipment due to the condition of the asset. Approximately 10 poles per year are replaced in emergencies.

Year	Amount
2018	$101,900
2019	$103,800
2020	$105,700
2021	$107,600
2022	$109,500

Risks to Completion and Risk Mitigation: Emergency locates required. Process in place for this.
Comparative Information on Equivalent Historical Projects (if any): This is a non-discretionary annual program. Related spending in previous years.
Renewable Energy Generation linkage: N/A
Non-distribution system options: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver:** This project is driven by the need to replace assets that have failed unexpectedly.
	Priority # N/A – Non **-** Discretionary project
	Investment effectiveness: Plant is replaced like-for-like or upgraded to accommodate future plans for the area.
Safety	Failed equipment represents a safety hazard to staff and the public. Replacement of failed plant restores the system to safe operating condition

Cyber Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Economic Development	N/A
Environmental benefits	N/A
C. Category-specific requirements: System Renewal	
Projects/activities in this category are driven by the relationship between the ability of an asset or asset system to continue to perform at an acceptable standard on a predictable basis on one hand and on the other, the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. "failure").	
Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure 1. Condition of Asset vs. Typical Life Cycle and Performance Record 2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure 3. Quantitative Customer Impacts (frequency or duration of interruptions and associated Risk level) 4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated Risk level) 5. Value of Customer Impact (high, medium, low)	1. Asset may fail due to deteriorated condition or to other factors that exceed design standards (i.e. vehicle impact) 2. Varies – pole failure may involve an entire feeder depending on location and protective device activated (ie. lateral fuse or circuit breaker, etc.) 3. Varies by location 4. Reduced outages will improve customer satisfaction. 5. Customer surveys show that reliability is ranked high in value to them
Factors that may affect the timing of the proposed project, including the rate at which assets are replaced over the forecast period (i.e. investment intensity), where applicable;	CPC has the resources and materials in order to ensure project completion on time. Emergency located required from others.
Consequences for system O&M costs, including the implications for system O&M of not implementing the project	N/A – failed equipment must be replaced
Reliability and or safety factors	New poles will be installed per CSA and 22/04 standards
Analysis of Project Benefits and Costs with alternative timing, expenditure, mitigation comparisons	N/A – immediate response required for reliability and safety reasons
Analysis of Project Benefits and Cost for extra cost "like for like". (System Access, System Service, General Plant benefit) (if applicable)	Pole class and loading design may be upgraded if it supports future plans for the area.
Other related information	N/A

Collus PowerStream
Capital Project

2018 - 2022

Project Name:	**SCADA and SmartMAP Enhancements**			
Project #:				
Investment Category:	**System Service**			
Investment Type:	**Discretionary**			
Service Area:	**Collingwood**			
Start Date:	**January 1, 2018**	**In Service Date:**	**December 31, 2022**	
Net Capital Cost: See below		**Gross Capital Cost:**	**See below**	
		Contributed Capital:	**$0**	
		OM&A Costs:	**$0**	
Expenditure Timing:	**Q1 $TBD**	**Q2 $TBD**	**Q3 $TBD**	**Q4 $TBD**

A. General Information:

Annual expenditures for SCADA and SmartMAP related initiatives.

Year	Amount
2018	$51,087
2019	$52,058
2020	$53,047
2021	$54,055
2022	$55,082

Risks to Completion and Risk Mitigation: Material and resources available
Comparative Information on Equivalent Historical Projects (if any): Similar to historical expenditures in this area.

Renewable Energy Generation linkage: N/A
Non-distribution system options: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver:** Continual improvement in Smart Grid capability.
	Priority # N/A – Annual expenditures to maintain software/hardware functionality
	Investment effectiveness: Improved smart grids capability and information quality/quantity can lead to reduced outage restoration time following unplanned outages; improved visibility of plant status for Operators; improved asset performance information
Safety	Improved visibility of equipment loading can improve system configuration decisions and raise operator awareness of equipment issues (i.e. overloading)
Cyber Security, Privacy	N/A

Co-ordination, Interoperability	N/A
Economic Development	Reliability of electrical supply is crucial to commercial and industrial businesses. It is a key component of any municipal economic development strategy.
Environmental benefits	N/A

C. Category-specific requirements: System Service	
Projects/activities in this category are driven by the distributor's expectations that evolving customer use of the system may occasion the creation of system capacity constraints or otherwise adversely impact operations in a manner that challenges the distributor's service delivery standards or objectives.	
Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable: -avoided costs	Improved operations performance due to enhanced information availability may lead to reduced outage times in certain situations; more effective asset management decision making
Regional Electricity Infrastructure Requirements which affected Project, if applicable	N/A
Description of how advanced technology (ie Smart Grid) has been incorporated into the project (if applicable) and including how standards relating to interoperability and cybersecurity have been met.	A Smart Grid related expenditure
Reliability, efficiency, safety and coordination benefits or effects the project will have on the distributor's system	Improved system configuration capability; real-time operator information; improved outage response
Factors affecting implementation timing/priority	Subject to annual needs over the 2018 – 2022 period
Project Analysis - Value Assessment -include monetary benefit, if applicable -technically feasible alternatives	Value matrix assessment: N/A
Project Analysis - Risk Assessment -impact of "do nothing" scenario -technically feasible alternatives -include monetary consequence, if applicable	Risk matrix assessment (1 year deferral Risk):N/A
Other related information	N/A

Collus PowerStream Capital Project

2018 - 2022

Project Name:	**General Plant – multiyear program expenditures**		
Project #:			
Investment Category:	**General Plant**		
Investment Type:	**Discretionary**		
Service Area:	**Collingwood**		
Start Date:	**January 1, 2018**	**In Service Date:**	**December 31, 2022**
Net Capital Cost: See below		**Gross Capital Cost:**	**See below**
		Contributed Capital:	**$0**
		OM&A Costs:	**$0**

Expenditure Timing:	**Q1**	**Q2**	**Q3**	**Q4**
	$TBD	**$TBD**	**$TBD**	**$TBD**

A. General Information:

General plant investments are modifications, replacements or additions to CPC's assets that are not part of the distribution system; including land and buildings; tools, equipment, electronic devices and software used to support day to day business and operations activities. In this category CPC has collected General Plant expenditures, excluding rolling stock that is reported separately, that while discrete in nature and timing, are expected to accumulate to material levels in a given year. See below:

	2018	2019	2020	2021	2022
Office Equipment	$ 20,000	$ 20,380	$ 20,767	$ 21,162	$ 21,564
Computer Equipment	$ 50,000	$ 50,950	$ 51,918	$ 52,905	$ 53,910
Computer Software	$ 50,000	$ 50,950	$ 51,918	$ 52,904	$ 53,909
Measurement & Testing Equipment	$ 31,930	$ 32,536	$ 33,154	$ 33,784	$ 34,426
Total	$ 151,930	$ 154,816	$ 157,757	$ 160,755	$ 163,809

Risks to Completion and Risk Mitigation: Material and resources are available
Comparative Information on Equivalent Historical Projects (if any): Similar to historical spending in these categories
Renewable Energy Generation linkage: N/A
Non-distribution system options: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver:** To meet system capital investment support, system maintenance support and business operations efficiency needs.
	Priority # N/A – Annual Expenditures required to maintain current functionality levels in administration and operations
	Investment effectiveness: Supports the effective operation of the distribution system.

Safety	N/A.	
Cyber Security, Privacy	N/A	
Co-ordination, Interoperability	N/A	
Economic Development	N/A	
Environmental benefits	N/A	
C. Category-specific requirements: General Plant		
Projects/activities in this category are driven by the distributor's evolving requirements for capital to support day to day business and operations activities.		
Project Analysis - Value Assessment -include monetary benefit, if applicable		Value matrix assessment: N/A
Project Analysis - Risk Assessment -impact of "do nothing" scenario -include monetary consequence, if applicable		Risk matrix assessment (1 year deferral Risk): N/A
High cost material projects business case details (>$250k)		N/A
Other related information		N/A

Collus PowerStream Capital Project

2018

Project Name:	**Overhead Pole Line rebuilds**		
Project #:			
Investment Category:	**System Renewal**		
Investment Type:	**Discretionary**		
Service Area:	**Collingwood**		
Start Date:	**January 1, 2018**	**In Service Date:**	**December 31, 2018**
Net Capital Cost: $1,487,740		**Gross Capital Cost:**	**$1,487,740**
		Contributed Capital:	**$0**
		OM&A Costs:	**$0**

Expenditure Timing:	**Q1**	**Q2**	**Q3**	**Q4**
	$260,000	**$500,000**	**$500,000**	**$227,470**

A. General Information:

The existing 4.16kV and 44kVpole lines are at end of life. End-of-life is determined through the inspection process and CPC's asset management program. 146 poles in total to be replaced and lines rebuilt to current standards. All poles are considered to be in "poor" or "very poor" condition. See project chart below:

Project	Poles	Cost
Collins - Katherine to Sproule (44kV)	12	$ 122,280
Raglan Street - Pretty River to Hume & Hospital (44kV)	24	$ 244,560
Raglan Street - Hume to Ron Emo (44kV)	26	$ 264,940
Osler Bluff Feeder Tie	26	$ 264,940
Birch Street Pole Line Rebuild (First St. - Third St.)	15	$ 152,850
Hickory Street Pole Line Rebuild (First St. - Fifth St.)	30	$ 305,700
Walnut Street Pole Line Rebuild (6th St. - 10th St.)	13	$ 132,470
Total	**146**	**$1,487,740**

Risks to Completion and Risk Mitigation: Material and labour resources available.

Comparative Information on Equivalent Historical Projects (if any): This is a discretionary program. Individual projects similar in scope to other pole line rebuild projects.

Renewable Energy Generation linkage: N/A

Non-distribution system options: N/A

B. Investment Evaluation Criteria	
Efficiency, Customer Value, Reliability	**Main Driver**: These projects are driven by the need to replace assets that have reached End-Of-Life status.
	Priority # 2018-2 through 8 – Discretionary projects.
	Investment effectiveness: Plant is replaced like-for-like or upgraded to as per plans for the area.
Safety	Poles at End-Of-Life represents a safety hazard to staff and the public. EOL status generally implies that pole structural strength has decreased to levels below the minimum acceptable per CSA Standard for Overhead construction. Replacement of EOL plant restores the system to safe structural and operating condition. Replacement plant to be installed in accordance with CSA construction standards and in compliance with ESA Reg. 22/04
Cyber Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Economic Development	N/A
Environmental benefits	N/A

C. Category-specific requirements: System Renewal	
Projects/activities in this category are driven by the relationship between the ability of an asset or asset system to continue to perform at an acceptable standard on a predictable basis on one hand and on the other, the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. "failure").	
Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure 1. Condition of Asset vs. Typical Life Cycle and Performance Record 2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure 3. Quantitative Customer Impacts (frequency or duration of interruptions and associated Risk level) 4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated Risk level) 5. Value of Customer Impact (high, medium, low)	1. Asset at EOL have reached the end of their life cycle. Future satisfactory performance in doubt. 2. Varies – 44kV pole failure may interrupt power to multiple MS depending on failure location. 3000+ customers may be impacted. 4.16kV pole failure may interrupt 500+ customers 3. Pole failure (multiple) could result in major interruption of 12-18 hours. 4. Reduced Risk of major outages will maintain customer satisfaction. 5. Customer surveys show that reliability is ranked high in value to them
Factors that may affect the timing of the proposed project, including the rate at which assets are replaced over the forecast period (i.e. investment intensity), where applicable;	CPC have the resources and materials in order to ensure project completion on time. Locates required from others.
Consequences for system O&M costs, including the implications for system O&M of	N/A – EOL equipment may fail unexpectedly and result in higher replacement costs (overtime, etc.) and higher

not implementing the project	outage costs to customers due to extended duration of unplanned outage
Reliability and or safety factors	New poles will be installed per CSA and 22/04 standards
Analysis of Project Benefits and Costs with alternative timing, expenditure, mitigation comparisons	Value/Risk result: 6.65 – 6.35 N/A – deferral increases Risk of unexpected failure; other alternatives (i.e. undergrounding) more expensive.
Analysis of Project Benefits and Cost for extra cost "like for like". (System Access, System Service, General Plant benefit) (if applicable)	Pole class and loading design may be upgraded to coincide with plans for the area.
Other related information	Multi-year program to replace entire sections of pole line that have been assessed to be in "very poor"/"poor" condition. Complements the Planned pole replacement project.

Collus PowerStream Capital Project

2018

Project Name:	**Replace vehicle 12-08 - 70' double bucket truck**			
Project #:				
Investment Category:	**General Plant**			
Investment Type:	**Discretionary**			
Service Area:	**Collingwood**			
Start Date:	**January 1, 2018**	**In Service Date:**	**December 31, 2018**	
Net Capital Cost: $500,000		**Gross Capital Cost:**	**$500,000**	
		Contributed Capital:	**$0**	
		OM&A Costs:	**$0**	
Expenditure Timing:	**Q1 $0**	**Q2 $0**	**Q3 $0**	**Q4 $500,000**

A. General Information:

A new 70' double bucket truck is to be procured to replace existing 70' double bucket truck #12-08 which has been assessed at economic end-of –life. Existing truck #12-08 is 8 years old and has well over 5000 engine hours of wear. Repairs and maintenance over the years have exceeded $76,000 which represents over 60 % of original cost. Repairs and maintenance costs are expected to remain high with continued operation. New vehicle will have reduced repair and maintenance costs.

Risks to Completion and Risk Mitigation: Delivery subject to manufacturer schedule.

Comparative Information on Equivalent Historical Projects (if any): Double bucket truck procured in 2012 at a cost of $356,000

Renewable Energy Generation linkage: N/A

Non-distribution system options: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver:** Replacement of aging fleet assets.
	Priority # 2018-9 - Discretionary project priority determined through the CPC capital prioritization process
	Investment effectiveness: The proposed fleet vehicle for replacement has reached the end of economic useful life. Reduced operating and maintenance expenses are expected.
Safety	The replaced vehicles will be matched to the work requirements and will reduce the Risk of improper work methods. The timing for fleet replacement ensures that vehicles are replaced before they deteriorate to a degree that represents an operational safety hazard.
Cyber Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Economic Development	N/A
Environmental benefits	New vehicle will be capable of using biodiesel fuel.

C. Category-specific requirements: General Plant	
Projects/activities in this category are driven by the distributor's evolving requirements for capital to support day to day business and operations activities.	
Project Analysis - Value Assessment -include monetary benefit, if applicable	Value matrix assessment: Safety goal linkage = Medium Reliability goal linkage = Medium Customer goal linkage = Low Finance goal linkage = Low
Project Analysis - Risk Assessment -impact of "do nothing" scenario -include monetary consequence, if applicable	Risk matrix assessment (1 year deferral Risk): Safety goal linkage = Negligible Reliability goal linkage = Moderate Customer goal linkage = Negligible Finance goal linkage = Negligible Potential for increased maintenance and fuel costs; reduced reliability
High cost material projects business case details (>$250k)	See attached business case
Other related information	N/A

Vehicle Replacement Assessment Guidelines[1]

Assessment Year	2016
Unit #	12-08
Year	2008
Description	Freightliner Double Bucket
Classification	Heavy
Original Cost	$377,013.93
Mileage	52660
Engine Hours	5089

Variable	Point Allocation	Performance factors	Points	2017
Age	1 point for each year of age	x years	8	9
Kilometers	1 point for each 25,000 km of use	xxxxx km	2	2
Engine Hours	1 point for each equivalent 25,000km of use (1 engine hour ~ 50km)	x hrs	10	11
Type of Service (duties or driving conditions)	1, 3 or 5 points based on type of service (ie harsh/offroad = 5; paved/daily use = 3; paved/non-daily use = 1)		3	3
Reliability	1, 3 or 5 points depending on frequency that vehicle is in shops for repair (ie. 2-3x/month = 5; 1x/3 months = 1)		2	1
Maintenance and Repair Costs	1, 3 or 5 points based on total life costs. (ie. lifetime costs > original vehicle cost = 5; lifetime costs <20% original vehicle cost = 1)		1	3
Condition	1, 3 or 5 points based on body condition, rust, interior condition, accident history , anticipated repairs,etc. (ie.		2	3
Other	1 - 5 points for any other condition criteria not covered above		1	1
		Total Points	**29.3**	**33.82**

Points evaluation	Light	Heavy
Very Good Condition	<20 pts	<18 pts
Good Condition	20 - 24 pts	18 - 22 pts
Fair Condition	24 - 29 pts	23 - 28 pts
Replacement condition	30+ points	29+ points

Condition Assessment **29**

Notes

Collus PowerStream Capital Project

2019

Project Name:	**Overhead Pole Line rebuilds**			
Project #:				
Investment Category:	**System Renewal**			
Investment Type:	**Discretionary**			
Service Area:	**Collingwood**			
Start Date:	**January 1, 2019**	**In Service Date:**	**December 31, 2019**	
Net Capital Cost: $1,545,860		**Gross Capital Cost:**	**$1,545,860**	
		Contributed Capital:	**$0**	
		OM&A Costs:	**$0**	
Expenditure Timing:	**Q1 $400,000**	**Q2 $400,000**	**Q3 $400,000**	**Q4 $345,860**

A. General Information:

The existing 4.16kV and 44kVpole lines are at end of life. End-of-life is determined through the inspection process and CPC's asset management program. 149 poles in total to be replaced and lines rebuilt to current standards. All poles are considered to be in "poor" or "very poor" condition. See project chart below:

Project	Poles	Cost
Napier North Rebuild	15	$ 155,700
Napier South Rebuild	10	$ 103,800
Hamilton - St. Marie to Hurontario	7	$ 72,660
Market Street - Hume to Market Lane	9	$ 93,420
Market Lane - St. Marie to St. Paul	6	$ 62,280
Elgin Street Pole Line Rebuild, Thornbury	12	$ 124,560
Alfred Street East & West Pole Line Rebuild (Bundled Conductor)	26	$ 269,880
Arthur Street East Pole Line Rebuild, Thornbury	22	$ 228,360
Beachwood Rd/Hwy 26 Pole Line Rebuild (BMC - Poplar S.R.)	42	$ 435,200
Total	**149**	**$1,545,860**

Risks to Completion and Risk Mitigation: Material and labour resources available.

Comparative Information on Equivalent Historical Projects (if any): This is a discretionary program. Individual projects similar in scope to other pole line rebuild projects.

Renewable Energy Generation linkage: N/A

Non-distribution system options: N/A

<table>
<tr><td colspan="3">B. Investment Evaluation Criteria</td></tr>
<tr><td rowspan="3">Efficiency, Customer Value, Reliability</td><td colspan="2">Main Driver: These projects are driven by the need to replace assets that have reached End-Of-Life status.</td></tr>
<tr><td colspan="2">Priority # 2019-2 through 6, 9,10, 16, 17 – Discretionary projects.</td></tr>
<tr><td colspan="2">Investment effectiveness: Plant is replaced like-for-like or upgraded to as per plans for the area.</td></tr>
<tr><td>Safety</td><td colspan="2">Poles at End-Of-Life represents a safety hazard to staff and the public. EOL status generally implies that pole structural strength has decreased to levels below the minimum acceptable per CSA Standard for Overhead construction. Replacement of EOL plant restores the system to safe structural and operating condition. Replacement plant to be installed in accordance with CSA construction standards and in compliance with ESA Reg. 22/04</td></tr>
<tr><td>Cyber Security, Privacy</td><td colspan="2">N/A</td></tr>
<tr><td>Co-ordination, Interoperability</td><td colspan="2">N/A</td></tr>
<tr><td>Economic Development</td><td colspan="2">N/A</td></tr>
<tr><td>Environmental benefits</td><td colspan="2">N/A</td></tr>
<tr><td colspan="3">C. Category-specific requirements: System Renewal</td></tr>
<tr><td colspan="3">Projects/activities in this category are driven by the relationship between the ability of an asset or asset system to continue to perform at an acceptable standard on a predictable basis on one hand and on the other, the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. “failure”).</td></tr>
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4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated Risk level)
5. Value of Customer Impact (high, medium, low)</td><td>1. Asset at EOL have reached the end of their life cycle. Future satisfactory performance in doubt.
2. Varies – 44kV pole failure may interrupt power to multiple MS depending on failure location. 3000+ customers may be impacted. 4.16kV pole failure may interrupt 500+ customers
3. Pole failure (multiple) could result in major interruption of 12-18 hours.
4. Reduced Risk of major outages will maintain customer satisfaction.
5. Customer surveys show that reliability is ranked high in value to them</td></tr>
<tr><td colspan="2">Factors that may affect the timing of the proposed project, including the rate at which assets are replaced over the forecast period (i.e. investment intensity), where applicable;</td><td>CPC have the resources and materials in order to ensure project completion on time. Locates required from others.</td></tr>
<tr><td colspan="2">Consequences for system O&M costs, including the implications for system O&M of</td><td>N/A – EOL equipment may fail unexpectedly and result in higher replacement costs (overtime, etc.) and higher</td></tr>
</table>

not implementing the project	outage costs to customers due to extended duration of unplanned outage
Reliability and or safety factors	New poles will be installed per CSA and 22/04 standards
Analysis of Project Benefits and Costs with alternative timing, expenditure, mitigation comparisons	Value/Risk result: 6.35 – 3.425 N/A – deferral increases Risk of unexpected failure; other alternatives (i.e. undergrounding) more expensive.
Analysis of Project Benefits and Cost for extra cost "like for like". (System Access, System Service, General Plant benefit) (if applicable)	Pole class and loading design may be upgraded to coincide with plans for the area.
Other related information	Multi-year program to replace entire sections of pole line that have been assessed to be in "very poor"/"poor" condition. Complements the Planned pole replacement project.

Collus PowerStream Capital Project

2019

Project Name:	**UG primary cable replacement**			
Project #:				
Investment Category:	**System Renewal**			
Investment Type:	**Discretionary**			
Service Area:	**Collingwood**			
Start Date:	**January 1, 2019**	**In Service Date:**	**December 31, 2019**	
Net Capital Cost: $259,500		**Gross Capital Cost:**	**$259,500**	
		Contributed Capital:	**$0**	
		OM&A Costs:	**$0**	
Expenditure Timing:	**Q1 $0**	**Q2 $125,000**	**Q3 $134,500**	**Q4 $0**

A. General Information:

This project involves the replacement of underground primary (5kV) cable in the following areas:

Project	Cable (m)	Cost
Harben Court Underground Primary Cable Replacement	425	$ 88,230
Mason Road Underground Primary Cable Replacement	825	$ 171,270
Total	**1250**	**$259,500**

The underground primary cable in these two areas is approximately 40 years old and through CPC's asset management program, has been determined to be at end-of-life. The cable is direct buried and will be replaced by cable in duct.

Risks to Completion and Risk Mitigation: Municipal approval timing. Material and resources available

Comparative Information on Equivalent Historical Projects (if any): This project is part of CPC's asset renewal program.

Renewable Energy Generation linkage: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver:** These projects are driven primarily by the need to replace assets that are aging and in poor condition and that pose a reliability Risk to the distribution system
	Priority # 2019-7,8 – Discretionary project priority determined through the CPC capital prioritization process
	Investment effectiveness: The underground cables are aged and assessed at end of life which makes them more prone to failure requiring frequent emergency repairs.
Safety	Elimination of faults will reduce stress and asset degradation on circuit components from the transformer station to the customer.
Cyber Security, Privacy	N/A

Co-ordination, Interoperability	N/A	
Economic Development	N/A	
Environmental benefits	N/A	
C. Category-specific requirements: System Renewal		
Projects/activities in this category are driven by the relationship between the ability of an asset or asset system to continue to perform at an acceptable standard on a predictable basis on one hand and on the other, the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. "failure").		
Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure 1. Condition of Asset vs. Typical Life Cycle and Performance Record 2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure 3. Quantitative Customer Impacts (frequency or duration of interruptions and associated Risk level) 4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated Risk level) 5. Value of Customer Impact (high, medium, low)	1. Underground cable is in poor to very poor condition. Underground cables are not installed in ducts, and are not TR-XLPE. 2. The proposed projects directly affect hundreds of customers. 3. Annual outage frequency due to failure = 2; Annual outage duration due to failure = 4 – 8 hours 4. Reduced outages will improve customer satisfaction. 5. Ranked high in safety value and medium in reliability to customer	
Factors that may affect the timing of the proposed project, including the rate at which assets are replaced over the forecast period (i.e. investment intensity), where applicable;	CPC has the resources and materials in order to ensure project completion on time.	
Consequences for system O&M costs, including the implications for system O&M of not implementing the project	Cable failures will require contractors to dig splice pits, and crew hours to repair cables.	
Reliability and or safety factors	New cable will be installed per 22/04 standards	
Analysis of Project Benefits and Costs with alternative timing, expenditure, mitigation comparisons	Rate of expenditure balances rate mitigation needs with decreasing asset reliability. Decreasing rate of expenditure will result in higher frequency Risk of outages to customers as asset replacement is delayed.	
Analysis of Project Benefits and Cost for extra cost "like for like". (System Access, System Service, General Plant benefit) (if applicable)	N/A	
Other related information	N/A	

Collus PowerStream Capital Project

2019

Project Name:	**UG primary cable and live-front transformer replacement**		
Project #:			
Investment Category:	**System Renewal**		
Investment Type:	**Discretionary**		
Service Area:	**Collingwood**		
Start Date:	**January 1, 2019**	**In Service Date:**	**December 31, 2019**
Net Capital Cost: $306,210		**Gross Capital Cost:**	**$306,210**
		Contributed Capital:	**$0**
		OM&A Costs:	**$0**

Expenditure Timing:	**Q1**	**Q2**	**Q3**	**Q4**
	$0	**$100,000**	**$100,000**	**$106,210**

A. General Information:

This project involves the replacement of underground primary (5kV) cable and live-front transformers in various locations in Collingwood. Locations and specific project costs are as follows:

Project	Cost
184 8th Street 5kV cables and Live Front Transformer Replacement	$57,090
233 St. Paul Street 5kV cable and Live Front Transformer Replacement	$57,090
Connaught Public School 5kV cable and Live Front Transformer Replacement	$57,090
Elm Street Apartment 5kV cable and Live Front Transformer Replacement	$57,090
10th Street Vista Blue Underground Rebuild Project	$77,850
Total	$306,210

The underground primary cable in these areas has been determined to be at end-of-life. The cable is direct buried and will be replaced by cable in duct. The transformers are live front and at end of life. Live front transformers are obsolete, at end of life and present reliability Risks and operating safety hazards to CPC personnel. To be replaced with dead front padmount transformers. The 10th Street Vista Blue rebuild involves the replacement of an obsolete switching unit (combination of a switch gear with a primary junction box) with a 4-way switch gear which will then feed a separate primary junction box.

Risks to Completion and Risk Mitigation: Municipal approval timing. Material and resources available
Comparative Information on Equivalent Historical Projects (if any): These projects are part of CPC's asset renewal program.

Renewable Energy Generation linkage: N/A

B. Investment Evaluation Criteria	
Efficiency, Customer Value, Reliability	**Main Driver:** This project is driven primarily by the need to replace assets that are aging and in poor condition and that pose a reliability Risk to the distribution system and are not constructed to current safety standards
	Priority # 2019- 11 through 15 – Discretionary project priority determined through the CPC capital prioritization process
	Investment effectiveness: The underground cables are aged and assessed at end of life which makes them more prone to failure requiring frequent emergency repairs. Unable to perform normal switching with these units. Outages are required. Investment will result in reduced customer outages and emergency repair activity. Will also improve public and personnel safety
Safety	Replacement of live front unit with dead front unit will provide for safer installation for working personnel and the public. Will be compliant with current ESA/CSA standards.
Cyber Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Economic Development	N/A
Environmental benefits	N/A
C. Category-specific requirements: System Renewal	
Projects/activities in this category are driven by the relationship between the ability of an asset or asset system to continue to perform at an acceptable standard on a predictable basis on one hand and on the other, the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. "failure").	
Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure 1. Condition of Asset vs. Typical Life Cycle and Performance Record 2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure 3. Quantitative Customer Impacts (frequency or duration of interruptions and associated Risk level) 4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated Risk level) 5. Value of Customer Impact (high, medium, low)	1. Underground cable is in poor to very poor condition. Underground cables are not installed in ducts, and are not TR-XLPE. Transformers are at end of life and are not constructed to current standards for a safe work environment. 2. The proposed projects directly affect hundreds of customers. Customers also affected by asset state which requires de-energization for routine switching. 3. Annual outage frequency due to failure/switching = 2; Annual outage duration due to failure/switching = 4 – 8 hours 4. Reduced outages for routine switching purposes will improve customer satisfaction. 5. Ranked high in safety value and medium in reliability to customer
Factors that may affect the timing of the proposed project, including the rate at which assets are replaced over the forecast period	CPC has the resources and materials in order to ensure project completion on time.

(i.e. investment intensity), where applicable;	
Consequences for system O&M costs, including the implications for system O&M of not implementing the project	Cable failures will require contractors to dig splice pits, and crew hours to repair cables.
Reliability and or safety factors	New cable will be installed per 22/04 standards. New transformers to current CSA standards.
Analysis of Project Benefits and Costs with alternative timing, expenditure, mitigation comparisons	Rate of expenditure balances rate mitigation needs with decreasing asset reliability. Decreasing rate of expenditure will result in higher frequency Risk of outages to customers as asset replacement is delayed.
Analysis of Project Benefits and Cost for extra cost "like for like". (System Access, System Service, General Plant benefit) (if applicable)	N/A
Other related information	N/A

Collus PowerStream Capital Project

2019

Project Name:	**Replace vehicle 14-04 – 2004 1 Ton Dump Truck**			
Project #:				
Investment Category:	**General Plant**			
Investment Type:	**Discretionary**			
Service Area:	**Collingwood**			
Start Date:	**January 1, 2019**	**In Service Date:**	**December 31, 2019**	
Net Capital Cost: $75,000		**Gross Capital Cost:**	**$75,000**	
		Contributed Capital:	**$0**	
		OM&A Costs:	**$0**	
Expenditure Timing:	**Q1 $0**	**Q2 $0**	**Q3 $75,000**	**Q4 $0**

A. General Information:

A 1 ton dump truck is to be procured to replace existing 1 ton dump truck #14-04 which has been assessed to be at economic end-of-life by 2019. Existing truck #14-04 will be 15 years old by 2019 and will have well over 75,000 km of wear. Repairs and maintenance costs are expected to increase with continued operation and vehicle body deterioration. New vehicle will have reduced repair and maintenance costs.

Risks to Completion and Risk Mitigation: Delivery subject to manufacturer schedule.

Comparative Information on Equivalent Historical Projects (if any): Existing vehicle procured in 2004 at a cost of $45,000

Renewable Energy Generation linkage: N/A

Non-distribution system options: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver:** Replacement of aging fleet assets.
	Priority # 2019-18 - Discretionary project priority determined through the CPC capital prioritization process
	Investment effectiveness: The proposed fleet vehicle for replacement has reached the end of economic useful life. Reduced operating and maintenance expenses are expected.
Safety	The replaced vehicles will be matched to the work requirements and will reduce the Risk of improper work methods. The timing for fleet replacement ensures that vehicles are replaced before they deteriorate to a degree that represents an operational safety hazard.
Cyber Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Economic Development	N/A
Environmental benefits	New vehicle will be capable of using biodiesel fuel.

C. Category-specific requirements: General Plant	
Projects/activities in this category are driven by the distributor's evolving requirements for capital to support day to day business and operations activities.	
Project Analysis - Value Assessment -include monetary benefit, if applicable	Value matrix assessment: Safety goal linkage = Medium Reliability goal linkage = Low Customer goal linkage = Low Finance goal linkage = Low Environment goal linkage = low
Project Analysis - Risk Assessment -impact of "do nothing" scenario -include monetary consequence, if applicable	Risk matrix assessment (1 year deferral Risk): Safety goal linkage = Negligible Customer goal linkage = Negligible Finance goal linkage = Negligible Environmental = Negligible Potential for increased maintenance and fuel costs; reduced reliability
High cost material projects business case details (>$250k)	See attached business case
Other related information	N/A

Vehicle Replacement Assessment Guidelines[1]

Assessment Year	2016
Unit #	14-04
Year	2004
Description	Ford - 1 Ton Dump Truck
Classification	Heavy
Original Cost	$45,030.00
Mileage	53198
Engine Hours	395

Variable	Point Allocation	Performance factors	Points	2017	2017	2018	2019
Age	1 point for each year of age	x years	12	13	14	15	16
Kilometers	1 point for each 25,000 km of use	xxxxx km	2	2	2	3	3
Engine Hours	1 point for each equivalent 25,000km of use (1 engine hour ~ 50km)	x hrs	1	1	1	1	1
Type of Service (duties or driving conditions)	1, 3 or 5 points based on type of service (ie harsh/offroad = 5; paved/daily use = 3; paved/non-daily use = 1)		3	3	3	3	3
Reliability	1, 3 or 5 points depending on frequency that vehicle is in shops for repair (ie. 2-3x/month = 5; 1x/3 months = 1)		1	1	1	1	1
Maintenance and Repair Costs	1, 3 or 5 points based on total life costs. (ie. lifetime costs > original vehicle cost = 5; lifetime costs <20% original vehicle cost = 1)		2	2	2	2	2
Condition	1, 3 or 5 points based on body condition, rust, interior condition, accident history , anticipated repairs,etc. (ie.		3	3	3	3	3
Other	1 - 5 points for any other condition criteria not covered above		1	1	1	1	1
	Total Points		**24.92**	**26.16**	**27.40**	**28.65**	**29.89**

Points evaluation	Light	Heavy
Very Good Condition	<20 pts	<18 pts
Good Condition	20 - 24 pts	18 - 22 pts
Fair Condition	24 - 29 pts	23 - 28 pts
Replacement condition	30+ points	29+ points

Condition Assessment **25**

Notes

Assessed by: xxxxxxxxx,Title

Date

Note 1 - Adapted from Guide to Vehicle Replacement and Right Sizing - Saskatchewan Ministry of Government Services

Note 2 - Box shade "red" - Replace; Box shade "yellow" - Fair; Box shade "green" - Good or Very Good

Collus PowerStream Capital Project

2019

Project Name:	**Replace vehicle 34-14 – 2014 ¾ Ton pickup Truck**		
Project #:			
Investment Category:	**General Plant**		
Investment Type:	**Discretionary**		
Service Area:	**Collingwood**		
Start Date:	**January 1, 2019**	**In Service Date:**	**December 31, 2019**
Net Capital Cost: $50,000		**Gross Capital Cost:**	**$50,000**
		Contributed Capital:	**$0**
		OM&A Costs:	**$0**

Expenditure Timing:	**Q1**	**Q2**	**Q3**	**Q4**
	$0	**$0**	**$50,000**	**$0**

A. General Information:

A ¾ ton pickup truck is to be procured to replace existing 3/4 ton pickup truck #34-14 which has been assessed to be at economic end-of –life by 2019. Existing truck #34-14 will be 5 years old by 2019 and will have well over 150,000 km of wear. Repairs and maintenance costs are expected to increase with continued operation and vehicle body deterioration. New vehicle will have reduced repair and maintenance costs.

Risks to Completion and Risk Mitigation: Delivery subject to manufacturer schedule.

Comparative Information on Equivalent Historical Projects (if any): Existing vehicle procured in 2014 at a cost of $44,000

Renewable Energy Generation linkage: N/A

Non-distribution system options: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver:** Replacement of aging fleet assets.
	Priority # 2019-19- Discretionary project priority determined through the CPC capital prioritization process
	Investment effectiveness: The proposed fleet vehicle for replacement has reached the end of economic useful life. Reduced operating and maintenance expenses are expected.
Safety	The replaced vehicles will be matched to the work requirements and will reduce the Risk of improper work methods. The timing for fleet replacement ensures that vehicles are replaced before they deteriorate to a degree that represents an operational safety hazard.
Cyber Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Economic Development	N/A
Environmental benefits	N/A

C. Category-specific requirements: General Plant	
Projects/activities in this category are driven by the distributor's evolving requirements for capital to support day to day business and operations activities.	
Project Analysis - Value Assessment -include monetary benefit, if applicable	Value matrix assessment: Safety goal linkage = Medium Reliability goal linkage = Medium Customer goal linkage = Low Finance goal linkage = Low
Project Analysis - Risk Assessment -impact of "do nothing" scenario -include monetary consequence, if applicable	Risk matrix assessment (1 year deferral Risk): Safety goal linkage = Negligible Customer goal linkage = Negligible Finance goal linkage = Negligible Potential for increased maintenance and fuel costs; reduced reliability
High cost material projects business case details (>$250k)	See attached business case
Other related information	N/A

Vehicle Replacement Assessment Guidelines[1]

Assessment Year	2016
Unit #	34-14
Year	2014
Description	Ford - 3/4 Ton Pickup
Classification	Light
Original Cost	$43,848.87
Mileage	50513
Engine Hours	2620

Variable	Point Allocation	Performance factors	Points	2017	2018	2019	2020
Age	1 point for each year of age	x years	2	3	4	5	6
Kilometers	1 point for each 25,000 km of use	xxxxx km	2	3	4	5	6
Engine Hours	1 point for each equivalent 25,000km of use (1 engine hour ~ 50km)	x hrs	5	8	10	13	16
Type of Service (duties or driving conditions)	1, 3 or 5 points based on type of service (ie harsh/offroad = 5; paved/daily use = 3; paved/non-daily use = 1)		3	3	3	3	3
Reliability	1, 3 or 5 points depending on frequency that vehicle is in shops for repair (ie. 2-3x/month = 5; 1x/3 months = 1)		1	1	1	1	1
Maintenance and Repair Costs	1, 3 or 5 points based on total life costs. (ie. lifetime costs > original vehicle cost = 5; lifetime costs <20% original vehicle cost = 1)		1	1	1	1	1
Condition	1, 3 or 5 points based on body condition, rust, interior condition, accident history , anticipated repairs,etc. (ie.		2	1	1	1	2
Other	1 - 5 points for any other condition criteria not covered above		1	1	1	1	1
	Total Points		**17.26**	**20.89**	**25.52**	**30.15**	**35.78**

Points evaluation	Light	Heavy
Very Good Condition	<20 pts	<18 pts
Good Condition	20 - 24 pts	18 - 22 pts
Fair Condition	24 - 29 pts	23 - 28 pts
Replacement condition	30+ points	29+ points

Condition Assessment **17**

Notes

Assessed by: xxxxxxxxx,Title

Date

Note 1 - Adapted from Guide to Vehicle Replacement and Right Sizing - Saskatchewan Ministry of Government Services

Note 2 - Box shade "red" - Replace; Box shade "yellow" - Fair; Box shade "green" - Good or Very Good

Collus PowerStream Capital Project

<table>
<tr><th colspan="5">2019</th></tr>
<tr><td>Project Name:</td><td colspan="4">Replace vehicle 31-13 – 2013 ½ Ton pickup Truck</td></tr>
<tr><td>Project #:</td><td colspan="4"></td></tr>
<tr><td>Investment Category:</td><td colspan="4">General Plant</td></tr>
<tr><td>Investment Type:</td><td colspan="4">Discretionary</td></tr>
<tr><td>Service Area:</td><td colspan="4">Collingwood</td></tr>
<tr><td>Start Date:</td><td>January 1, 2019</td><td>In Service Date:</td><td colspan="2">December 31, 2019</td></tr>
<tr><td colspan="2" rowspan="3">Net Capital Cost: $50,000</td><td>Gross Capital Cost:</td><td colspan="2">$50,000</td></tr>
<tr><td>Contributed Capital:</td><td colspan="2">$0</td></tr>
<tr><td>OM&A Costs:</td><td colspan="2">$0</td></tr>
<tr><td>Expenditure Timing:</td><td>Q1
$0</td><td>Q2
$0</td><td>Q3
$50,000</td><td>Q4
$0</td></tr>
<tr><td colspan="5">A. General Information:</td></tr>
<tr><td colspan="5">A ½ ton pickup truck is to be procured to replace existing 1/2 ton pickup truck #31-13 which has been assessed to be at economic end-of –life by 2019. Existing truck #31-13 will be 6 years old by 2019 and will have well over 125,000 km of wear. Repairs and maintenance costs are expected to increase with continued operation and vehicle body deterioration. New vehicle will have reduced repair and maintenance costs.
Risks to Completion and Risk Mitigation: Delivery subject to manufacturer schedule.
Comparative Information on Equivalent Historical Projects (if any): Existing vehicle procured in 2013 at a cost of $31,000
Renewable Energy Generation linkage: N/A
Non-distribution system options: N/A</td></tr>
<tr><td colspan="5">B. Investment Evaluation Criteria</td></tr>
<tr><td rowspan="3">Efficiency, Customer Value, Reliability</td><td colspan="4">Main Driver: Replacement of aging fleet assets.</td></tr>
<tr><td colspan="4">Priority # 2019-20 - Discretionary project priority determined through the CPC capital prioritization process</td></tr>
<tr><td colspan="4">Investment effectiveness: The proposed fleet vehicle for replacement has reached the end of economic useful life. Reduced operating and maintenance expenses are expected.</td></tr>
<tr><td>Safety</td><td colspan="4">The replaced vehicles will be matched to the work requirements and will reduce the Risk of improper work methods. The timing for fleet replacement ensures that vehicles are replaced before they deteriorate to a degree that represents an operational safety hazard.</td></tr>
<tr><td>Cyber Security, Privacy</td><td colspan="4">N/A</td></tr>
<tr><td>Co-ordination, Interoperability</td><td colspan="4">N/A</td></tr>
<tr><td>Economic Development</td><td colspan="4">N/A</td></tr>
</table>

Environmental benefits	N/A
C. Category-specific requirements: General Plant	
Projects/activities in this category are driven by the distributor's evolving requirements for capital to support day to day business and operations activities.	
Project Analysis - Value Assessment -include monetary benefit, if applicable	Value matrix assessment: Safety goal linkage = Medium Reliability goal linkage = Low Customer goal linkage = Low Finance goal linkage = Low
Project Analysis - Risk Assessment -impact of "do nothing" scenario -include monetary consequence, if applicable	Risk matrix assessment (1 year deferral Risk): Safety goal linkage = Negligible Reliability goal linkage = Negligible Customer goal linkage = Negligible Finance goal linkage = Negligible Potential for increased maintenance and fuel costs; reduced reliability
High cost material projects business case details (>$250k)	See attached business case
Other related information	N/A

Vehicle Replacement Assessment Guidelines[1]

Assessment Year	2016
Unit #	31-13
Year	2013
Description	Dodge - 1/2 Ton Pickup
Classification	Light
Original Cost	$24,924.42
Mileage	58010
Engine Hours	2413

Variable	Point Allocation	Performance factors	Points	2017	2018	2019	2020
Age	1 point for each year of age	x years	3	4	5	6	7
Kilometers	1 point for each 25,000 km of use	xxxxx km	2	3	4	5	5
Engine Hours	1 point for each equivalent 25,000km of use (1 engine hour ~ 50km)	x hrs	5	6	8	10	11
Type of Service (duties or driving conditions)	1, 3 or 5 points based on type of service (ie harsh/offroad = 5; paved/daily use = 3; paved/non-daily use = 1)		3	3	3	3	3
Reliability	1, 3 or 5 points depending on frequency that vehicle is in shops for repair (ie. 2-3x/month = 5; 1x/3 months = 1)		1	1	1	1	1
Maintenance and Repair Costs	1, 3 or 5 points based on total life costs. (ie. lifetime costs > original vehicle cost = 5; lifetime costs <20% original vehicle cost = 1)		1	1	1	1	1
Condition	1, 3 or 5 points based on body condition, rust, interior condition, accident history , anticipated repairs,etc. (ie.		1	1	1	1	2
Other	1 - 5 points for any other condition criteria not covered above		1	1	1	1	1
	Total Points		**17.15**	**20.53**	**23.91**	**27.29**	**31.67**

Points evaluation	Light	Heavy
Very Good Condition	<20 pts	<18 pts
Good Condition	20 - 24 pts	18 - 22 pts
Fair Condition	24 - 29 pts	23 - 28 pts
Replacement condition	30+ points	29+ points

Condition Assessment **17**

Notes

Assessed by: xxxxxxxxx,Title

Date

Note 1 - Adapted from Guide to Vehicle Replacement and Right Sizing - Saskatchewan Ministry of Government Services

Note 2 - Box shade "red" - Replace; Box shade "yellow" - Fair; Box shade "green" - Good or Very Good

Collus PowerStream Capital Project

2019

Project Name:	**Replace vehicle 10-09 – 2009 Ford Escape**		
Project #:			
Investment Category:	**General Plant**		
Investment Type:	**Discretionary**		
Service Area:	**Collingwood**		
Start Date:	**January 1, 2019**	**In Service Date:**	**December 31, 2019**
Net Capital Cost: $35,000		**Gross Capital Cost:**	**$35,000**
		Contributed Capital:	**$0**
		OM&A Costs:	**$0**

Expenditure Timing:	**Q1**	**Q2**	**Q3**	**Q4**
	$0	**$35,000**	**$0**	**$0**

A. General Information:

A new passenger vehicle is to be procured to replace existing Ford Escape #10-09 which has been assessed to be at economic end-of –life by 2018. Existing truck #10-09 will be 10 years old by 2019 and will have well over 200,000 km of wear. Repairs and maintenance costs are expected to increase with continued operation and vehicle body deterioration. New vehicle will have reduced repair and maintenance costs.

Risks to Completion and Risk Mitigation: Delivery subject to manufacturer schedule.

Comparative Information on Equivalent Historical Projects (if any): Existing vehicle procured in 2009at a cost of $22,000

Renewable Energy Generation linkage: N/A

Non-distribution system options: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver:** Replacement of aging fleet assets.
	Priority # 2019-21 - Discretionary project priority determined through the CPC capital prioritization process
	Investment effectiveness: The proposed fleet vehicle for replacement has reached the end of economic useful life. Reduced operating and maintenance expenses are expected.
Safety	The replaced vehicles will be matched to the work requirements and will reduce the Risk of improper work methods. The timing for fleet replacement ensures that vehicles are replaced before they deteriorate to a degree that represents an operational safety hazard.
Cyber Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Economic Development	N/A
Environmental benefits	N/A

C. Category-specific requirements: General Plant	
Projects/activities in this category are driven by the distributor's evolving requirements for capital to support day to day business and operations activities.	
Project Analysis - Value Assessment -include monetary benefit, if applicable	Value matrix assessment: Safety goal linkage = High Finance goal linkage = Low
Project Analysis - Risk Assessment -impact of "do nothing" scenario -include monetary consequence, if applicable	Risk matrix assessment (1 year deferral Risk): Safety goal linkage = Negligible Customer goal linkage = Negligible Finance goal linkage = Negligible Potential for increased maintenance and fuel costs; reduced reliability
High cost material projects business case details (>$250k)	See attached business case
Other related information	N/A

Vehicle Replacement Assessment Guidelines[1]

Assessment Year	2016
Unit #	10-09
Year	2009
Description	Ford Escape - Passenger
Classification	Light
Original Cost	$22,055.00
Mileage	153246
Engine Hours	1407

Variable	Point Allocation	Performance factors	Points	2017	2018	2019
Age	1 point for each year of age	x years	7	8	9	10
Kilometers	1 point for each 25,000 km of use	xxxxx km	6	7	8	9
Engine Hours	1 point for each equivalent 25,000km of use (1 engine hour ~ 50km)	x hrs	3	3	4	4
Type of Service (duties or driving conditions)	1, 3 or 5 points based on type of service (ie harsh/offroad = 5; paved/daily use = 3; paved/non-daily use = 1)		3	3	3	3
Reliability	1, 3 or 5 points depending on frequency that vehicle is in shops for repair (ie. 2-3x/month = 5; 1x/3 months = 1)		1	1	1	1
Maintenance and Repair Costs	1, 3 or 5 points based on total life costs. (ie. lifetime costs > original vehicle cost = 5; lifetime costs <20% original vehicle cost = 1)		3	3	3	3
Condition	1, 3 or 5 points based on body condition, rust, interior condition, accident history , anticipated repairs,etc. (ie.		3	3	3	3
Other	1 - 5 points for any other condition criteria not covered above		1	1	1	1
	Total Points		**26.94**	**29.22**	**31.50**	**33.78**

Points evaluation	Light	Heavy
Very Good Condition	<20 pts	<18 pts
Good Condition	20 - 24 pts	18 - 22 pts
Fair Condition	24 - 29 pts	23 - 28 pts
Replacement condition	30+ points	29+ points

Condition Assessment **27**

Notes

Assessed by: xxxxxxxxx,Title

Date

Note 1 - Adapted from Guide to Vehicle Replacement and Right Sizing - Saskatchewan Ministry of Government Services

Collus PowerStream Capital Project

2020

Project Name:	**Overhead Pole Line rebuilds**		
Project #:			
Investment Category:	**System Renewal**		
Investment Type:	**Discretionary**		
Service Area:	**Collingwood**		
Start Date:	**January 1, 2020**	**In Service Date:**	**December 31, 2020**
Net Capital Cost: $1,860,320		**Gross Capital Cost:**	**$1,860,320**
		Contributed Capital:	**$0**
		OM&A Costs:	**$0**

Expenditure Timing:	**Q1**	**Q2**	**Q3**	**Q4**
	$400,000	**$500,000**	**$500,000**	**$460,320**

A. General Information:

The existing 4.16kV and 44kVpole lines are at end of life. End-of-life is determined through the inspection process and CPC's asset management program. 176 poles in total to be replaced and lines rebuilt to current standards. All poles are considered to be in "poor" or "very poor" condition. See project chart below:

Project	Poles	Cost
Brock Street to MS1 Stayner Part 3	36	$ 380,520
First Street Ext. Pole Line Rebuild (Old Mountain Rd to High St.)	9	$ 95,130
Fourth Street Pole Line Rebuild (Hickory St. - Pine St.)	25	$ 264,250
High Street Pole Line Rebuild (Murray Court to Fifth St.)	20	$ 211,400
Highway 26 to Brock St Stayner Part 2	24	$ 253,680
MS2 - Stayner Street, Stayner Part 1	20	$ 211,400
Oliver Crescent Pole Line Rebuild	12	$ 126,840
Rodney St. Pole Line Rebuild (Peel St. - Huron St.)	10	$ 105,700
Third Street Pole Line Rebuild (Spruce St. - Birch St.)	20	$ 211,400
Total	**176**	**$1,860,320**

Risks to Completion and Risk Mitigation: Material and labour resources available.

Comparative Information on Equivalent Historical Projects (if any): This is a discretionary program. Individual projects similar in scope to other pole line rebuild projects.

Renewable Energy Generation linkage: N/A

Non-distribution system options: N/A

B. Investment Evaluation Criteria	
Efficiency, Customer Value, Reliability	**Main Driver**: These projects are driven by the need to replace assets that have reached End-Of-Life status.
	Priority # 2020-3 through 11– Discretionary projects.
	Investment effectiveness: Plant is replaced like-for-like or upgraded to as per plans for the area.
Safety	Poles at End-Of-Life represents a safety hazard to staff and the public. EOL status generally implies that pole structural strength has decreased to levels below the minimum acceptable per CSA Standard for Overhead construction. Replacement of EOL plant restores the system to safe structural and operating condition. Replacement plant to be installed in accordance with CSA construction standards and in compliance with ESA Reg. 22/04
Cyber Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Economic Development	N/A
Environmental benefits	N/A

C. Category-specific requirements: System Renewal	
Projects/activities in this category are driven by the relationship between the ability of an asset or asset system to continue to perform at an acceptable standard on a predictable basis on one hand and on the other, the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. "failure").	
Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure 1. Condition of Asset vs. Typical Life Cycle and Performance Record 2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure 3. Quantitative Customer Impacts (frequency or duration of interruptions and associated Risk level) 4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated Risk level) 5. Value of Customer Impact (high, medium, low)	1. Asset at EOL have reached the end of their life cycle. Future satisfactory performance in doubt. 2. Varies – 44kV pole failure may interrupt power to multiple MS depending on failure location. 3000+ customers may be impacted. 4.16kV pole failure may interrupt 500+ customers 3. Pole failure (multiple) could result in major interruption of 12-18 hours. 4. Reduced Risk of major outages will maintain customer satisfaction. 5. Customer surveys show that reliability is ranked high in value to them
Factors that may affect the timing of the proposed project, including the rate at which assets are replaced over the forecast period (i.e. investment intensity), where applicable;	CPC have the resources and materials in order to ensure project completion on time. Locates required from others.
Consequences for system O&M costs, including the implications for system O&M of	N/A – EOL equipment may fail unexpectedly and result in higher replacement costs (overtime, etc.) and higher

not implementing the project	outage costs to customers due to extended duration of unplanned outage
Reliability and or safety factors	New poles will be installed per CSA and 22/04 standards
Analysis of Project Benefits and Costs with alternative timing, expenditure, mitigation comparisons	Value/Risk result: 3.425 N/A – deferral increases Risk of unexpected failure; other alternatives (i.e. undergrounding) more expensive.
Analysis of Project Benefits and Cost for extra cost "like for like". (System Access, System Service, General Plant benefit) (if applicable)	Pole class and loading design may be upgraded to coincide with plans for the area.
Other related information	Multi-year program to replace entire sections of pole line that have been assessed to be in "very poor"/"poor" condition. Complements the Planned pole replacement project.

Collus PowerStream Capital Project

2020

Project Name:	**Replace vehicle 33-12 - 70' double bucket truck**				
Project #:					
Investment Category:	**General Plant**				
Investment Type:	**Discretionary**				
Service Area:	**Collingwood**				
Start Date:	**January 1, 2018**		**In Service Date:**	**December 31, 2018**	
Net Capital Cost: $500,000			**Gross Capital Cost:**	**$500,000**	
			Contributed Capital:	**$0**	
			OM&A Costs:	**$0**	
Expenditure Timing:	**Q1** **$0**	**Q2** **$0**	**Q3** **$0**	**Q4** **$500,000**	

A. General Information:

A new 70' double bucket truck is to be procured to replace existing 70' double bucket truck #33-12 which has been assessed to be at economic end-of –life by 2020. Existing truck #33-12 will be 8 years old and will have over 5000 engine hours of wear. Repairs and maintenance to 2016 have exceeded $46,000. Repairs and maintenance costs are expected to grow with continued operation. New vehicle will have reduced repair and maintenance costs.

Risks to Completion and Risk Mitigation: Delivery subject to manufacturer schedule.

Comparative Information on Equivalent Historical Projects (if any): Double bucket truck procured in 2012 at a cost of $356,000

Renewable Energy Generation linkage: N/A

Non-distribution system options: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver:** Replacement of aging fleet assets.
	Priority # 2020-2 - Discretionary project priority determined through the CPC capital prioritization process
	Investment effectiveness: The proposed fleet vehicle for replacement has reached the end of economic useful life. Reduced operating and maintenance expenses are expected.
Safety	The replaced vehicles will be matched to the work requirements and will reduce the Risk of improper work methods. The timing for fleet replacement ensures that vehicles are replaced before they deteriorate to a degree that represents an operational safety hazard.
Cyber Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Economic Development	N/A
Environmental benefits	New vehicle will be capable of using biodiesel fuel.

C. Category-specific requirements: General Plant	
Projects/activities in this category are driven by the distributor's evolving requirements for capital to support day to day business and operations activities.	
Project Analysis - Value Assessment -include monetary benefit, if applicable	Value matrix assessment: Safety goal linkage = Medium Reliability goal linkage = Medium Customer goal linkage = Low Finance goal linkage = Low
Project Analysis - Risk Assessment -impact of "do nothing" scenario -include monetary consequence, if applicable	Risk matrix assessment (1 year deferral Risk): Safety goal linkage = Negligible Reliability goal linkage = Moderate Customer goal linkage = Negligible Finance goal linkage = Negligible Potential for increased maintenance and fuel costs; reduced reliability
High cost material projects business case details (>$250k)	See attached business case
Other related information	N/A

Vehicle Replacement Assessment Guidelines[1]

Assessment Year	2016
Unit #	33-12
Year	2012
Description	Freightliner Double Bucket
Classification	Heavy
Original Cost	$356,047.94
Mileage	22566
Engine Hours	2381

Variable	Point Allocation	Performance factors	Points	2017	2018	2019	2020
Age	1 point for each year of age	x years	4	5	6	7	8
Kilometers	1 point for each 25,000 km of use	xxxxx km	1	1	1	2	2
Engine Hours	1 point for each equivalent 25,000km of use (1 engine hour ~ 50km)	x hrs	5	6	7	8	10
Type of Service (duties or driving conditions)	1, 3 or 5 points based on type of service (ie harsh/offroad = 5; paved/daily use = 3; paved/non-daily use = 1)		3	3	3	3	3
Reliability	1, 3 or 5 points depending on frequency that vehicle is in shops for repair (ie. 2-3x/month = 5; 1x/3 months = 1)		2	1	1	1	2
Maintenance and Repair Costs	1, 3 or 5 points based on total life costs. (ie. lifetime costs > original vehicle cost = 5; lifetime costs <20% original vehicle cost = 1)		1	1	1	2	2
Condition	1, 3 or 5 points based on body condition, rust, interior condition, accident history , anticipated repairs,etc. (ie.		2	1	1	1	2
Other	1 - 5 points for any other condition criteria not covered above		1	1	1	1	1
	Total Points		18.66	19.08	21.50	24.91	29.33

Points evaluation	Light	Heavy
Very Good Condition	<20 pts	<18 pts
Good Condition	20 - 24 pts	18 - 22 pts
Fair Condition	24 - 29 pts	23 - 28 pts
Replacement condition	30+ points	29+ points

Condition Assessment **19**

Notes

Assessed by: xxxxxxxxx,Title

Date

Note 1 - Adapted from Guide to Vehicle Replacement and Right Sizing - Saskatchewan Ministry of Government Services

Note 2 - Box shade "red" - Replace; Box shade "yellow" - Fair; Box shade "green" - Good or Very Good

Collus PowerStream Capital Project

2021

Project Name:	**Overhead Pole Line rebuilds**		
Project #:			
Investment Category:	**System Renewal**		
Investment Type:	**Discretionary**		
Service Area:	**Collingwood**		
Start Date:	**January 1, 2021**	**In Service Date:**	**December 31, 2021**
Net Capital Cost: $1,908,914		**Gross Capital Cost:**	**$1,908,914**
		Contributed Capital:	**$0**
		OM&A Costs:	**$0**

Expenditure Timing:	**Q1**	**Q2**	**Q3**	**Q4**
	$500,000	**$500,000**	**$500,000**	**$408,914**

A. General Information:

The existing 4.16kV and 44kVpole lines are at end of life. End-of-life is determined through the inspection process and CPC's asset management program. 169 poles in total to be replaced and lines rebuilt to current standards. All poles are considered to be in "poor" or "very poor" condition. See project chart below:

Project	Poles	Cost
Ontario Street Rebuild	15	$ 161,400
Mountain Road Rebuild	70	$ 753,200
Oak/Ferguson Rear lot	7	$ 86,618
Hurontario n/o Simcoe Street Rear lot rebuild	7	$ 86,618
Hurontario East- North & South of Third Street	12	$ 129,120
Mason/Dickson Rear Lot	9	$ 111,366
Park/Ferguson Rear Lot	9	$ 111,366
Park/Trail Rear Lot	4	$ 49,496
Clarkson Crescent West Rear lot	4	$ 49,496
Clarkson/Oak Rear lot	7	$ 86,618
Oak/Dickson Rear lot	9	$ 111,366
Peel Street - South of Hume	10	$ 107,600
St. Marie Street - Hume to Hamilton	6	$ 64,560
Total	**169**	**$1,908,824**

Risks to Completion and Risk Mitigation: Material and labour resources available.

Comparative Information on Equivalent Historical Projects (if any): This is a discretionary program. Individual projects similar in scope to other pole line rebuild projects.

Renewable Energy Generation linkage: N/A

<table>
<tr><td colspan="3">Non-distribution system options: N/A</td></tr>
<tr><td colspan="3">B. Investment Evaluation Criteria</td></tr>
<tr><td rowspan="3">Efficiency, Customer Value, Reliability</td><td colspan="2">Main Driver: These projects are driven by the need to replace assets that have reached End-Of-Life status.</td></tr>
<tr><td colspan="2">Priority # 2021-3 through 15 – Discretionary projects.</td></tr>
<tr><td colspan="2">Investment effectiveness: Plant is replaced like-for-like or upgraded to as per plans for the area.</td></tr>
<tr><td>Safety</td><td colspan="2">Poles at End-Of-Life represents a safety hazard to staff and the public. EOL status generally implies that pole structural strength has decreased to levels below the minimum acceptable per CSA Standard for Overhead construction. Replacement of EOL plant restores the system to safe structural and operating condition. Replacement plant to be installed in accordance with CSA construction standards and in compliance with ESA Reg. 22/04</td></tr>
<tr><td>Cyber Security, Privacy</td><td colspan="2">N/A</td></tr>
<tr><td>Co-ordination, Interoperability</td><td colspan="2">N/A</td></tr>
<tr><td>Economic Development</td><td colspan="2">N/A</td></tr>
<tr><td>Environmental benefits</td><td colspan="2">N/A</td></tr>
<tr><td colspan="3">C. Category-specific requirements: System Renewal</td></tr>
<tr><td colspan="3">Projects/activities in this category are driven by the relationship between the ability of an asset or asset system to continue to perform at an acceptable standard on a predictable basis on one hand and on the other, the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. “failure”).</td></tr>
<tr><td colspan="2">Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure
1. Condition of Asset vs. Typical Life Cycle and Performance Record
2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure
3. Quantitative Customer Impacts (frequency or duration of interruptions and associated Risk level)
4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated Risk level)
5. Value of Customer Impact (high, medium, low)</td><td>1. Asset at EOL have reached the end of their life cycle. Future satisfactory performance in doubt.
2. Varies – 44kV pole failure may interrupt power to multiple MS depending on failure location. 3000+ customers may be impacted. 4.16kV pole failure may interrupt 500+ customers
3. Pole failure (multiple) could result in major interruption of 12-18 hours.
4. Reduced Risk of major outages will maintain customer satisfaction.
5. Customer surveys show that reliability is ranked high in value to them</td></tr>
<tr><td colspan="2">Factors that may affect the timing of the proposed project, including the rate at which assets are replaced over the forecast period (i.e. investment intensity), where applicable;</td><td>CPC have the resources and materials in order to ensure project completion on time. Locates required from others.</td></tr>
</table>

Consequences for system O&M costs, including the implications for system O&M of not implementing the project	N/A – EOL equipment may fail unexpectedly and result in higher replacement costs (overtime, etc.) and higher outage costs to customers due to extended duration of unplanned outage
Reliability and or safety factors	New poles will be installed per CSA and 22/04 standards
Analysis of Project Benefits and Costs with alternative timing, expenditure, mitigation comparisons	Value/Risk result: 3.425 N/A – deferral increases Risk of unexpected failure; other alternatives (i.e. undergrounding) more expensive.
Analysis of Project Benefits and Cost for extra cost "like for like". (System Access, System Service, General Plant benefit) (if applicable)	Pole class and loading design may be upgraded to coincide with plans for the area.
Other related information	Multi-year program to replace entire sections of pole line that have been assessed to be in "very poor"/"poor" condition. Complements the Planned pole replacement project.

Collus PowerStream Capital Project

2021

Project Name:	**Replace vehicle 18-15 - 36' single bucket truck**				
Project #:					
Investment Category:	**General Plant**				
Investment Type:	**Discretionary**				
Service Area:	**Collingwood**				
Start Date:	**January 1, 2018**		**In Service Date:**	**December 31, 2018**	
Net Capital Cost: $425,000			**Gross Capital Cost:**	**$425,000**	
			Contributed Capital:	**$0**	
			OM&A Costs:	**$0**	
Expenditure Timing:	**Q1** $0	**Q2** $0	**Q3** $0	**Q4** $425,000	

A. General Information:

A new 36' single bucket truck is to be procured to replace existing 36' single bucket truck #18-15 which has been assessed to be at economic end-of–life by 2019. This vehicle is used as a trouble truck and is subject to continual heavy duty use. Existing truck #18-15 will be 6 years old and will have over 10000 engine hours of wear and will have over 175,000 km of mileage. Repairs and maintenance to 2016 have exceeded $50,000. Repairs and maintenance costs are expected to grow with continued operation. New vehicle will have reduced repair and maintenance costs.

Risks to Completion and Risk Mitigation: Delivery subject to manufacturer schedule.

Comparative Information on Equivalent Historical Projects (if any): Single bucket truck procured in 2015 at a cost of $263,000

Renewable Energy Generation linkage: N/A

Non-distribution system options: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver:** Replacement of aging fleet assets.
	Priority # 2021-2 - Discretionary project priority determined through the CPC capital prioritization process
	Investment effectiveness: The proposed fleet vehicle for replacement has reached the end of economic useful life. Reduced operating and maintenance expenses are expected.
Safety	The replaced vehicles will be matched to the work requirements and will reduce the Risk of improper work methods. The timing for fleet replacement ensures that vehicles are replaced before they deteriorate to a degree that represents an operational safety hazard.
Cyber Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Economic Development	N/A

Environmental benefits	New vehicle will be capable of using biodiesel fuel.
C. Category-specific requirements: General Plant	
Projects/activities in this category are driven by the distributor's evolving requirements for capital to support day to day business and operations activities.	
Project Analysis - Value Assessment -include monetary benefit, if applicable	Value matrix assessment: Safety goal linkage = Medium Reliability goal linkage = Medium Customer goal linkage = Low Finance goal linkage = Low
Project Analysis - Risk Assessment -impact of "do nothing" scenario -include monetary consequence, if applicable	Risk matrix assessment (1 year deferral Risk): Safety goal linkage = Negligible Reliability goal linkage = Moderate Customer goal linkage = Negligible Finance goal linkage = Negligible Potential for increased maintenance and fuel costs; reduced reliability
High cost material projects business case details (>$250k)	See attached business case
Other related information	N/A

Vehicle Replacement Assessment Guidelines[1]

Assessment Year	2016
Unit #	18-15
Year	2015
Description	Freightliner Single Bucket
Classification	Heavy
Original Cost	$262,295.05
Mileage	33559
Engine Hours	2027

Variable	Point Allocation	Performance factors	Points	2017	2018	2019	2020
Age	1 point for each year of age	x years	1	2	3	4	5
Kilometers	1 point for each 25,000 km of use	xxxxx km	1	3	4	5	7
Engine Hours	1 point for each equivalent 25,000km of use (1 engine hour ~ 50km)	x hrs	4	8	12	16	20
Type of Service (duties or driving conditions)	1, 3 or 5 points based on type of service (ie harsh/offroad = 5; paved/daily use = 3; paved/non-daily use = 1)		3	3	3	3	3
Reliability	1, 3 or 5 points depending on frequency that vehicle is in shops for repair (ie. 2-3x/month = 5; 1x/3 months = 1)		1	1	1	1	2
Maintenance and Repair Costs	1, 3 or 5 points based on total life costs. (ie. lifetime costs > original vehicle cost = 5; lifetime costs <20% original vehicle cost = 1)		1	1	1	2	2
Condition	1, 3 or 5 points based on body condition, rust, interior condition, accident history , anticipated repairs,etc. (ie.		2	1	1	1	2
Other	1 - 5 points for any other condition criteria not covered above		1	1	1	1	1
		Total Points	**14.4**	**19.79**	**26.19**	**33.59**	**41.98**

Points evaluation	Light	Heavy
Very Good Condition	<20 pts	<18 pts
Good Condition	20 - 24 pts	18 - 22 pts
Fair Condition	24 - 29 pts	23 - 28 pts
Replacement condition	30+ points	29+ points

Condition Assessment **14**

Notes

Assessed by: xxxxxxxxx,Title

Date

Note 1 - Adapted from Guide to Vehicle Replacement and Right Sizing - Saskatchewan Ministry of Government Services

Note 2 - Box shade "red" - Replace; Box shade "yellow" - Fair; Box shade "green" - Good or Very Good

Collus PowerStream Capital Project

2022

Project Name:	**Overhead Pole Line rebuilds**			
Project #:				
Investment Category:	**System Renewal**			
Investment Type:	**Discretionary**			
Service Area:	**Collingwood**			
Start Date:	**January 1, 2022**	**In Service Date:**	**December 31, 2022**	
Net Capital Cost: $2,124,300		**Gross Capital Cost:**	**$2,124,300**	
		Contributed Capital:	**$0**	
		OM&A Costs:	**$0**	
Expenditure Timing:	**Q1 $500,000**	**Q2 $550,000**	**Q3 $550,000**	**Q4 $524,300**

A. General Information:

The existing 4.16kV and 44kVpole lines are at end of life. End-of-life is determined through the inspection process and CPC's asset management program. 194 poles in total to be replaced and lines rebuilt to current standards. All poles are considered to be in "poor" or "very poor" condition. See project chart below:

Project	Poles	Cost
Robinson Street - Hume to Collins	24	$ 262,800
Campbell Street - Herrington Court to High Street	10	$ 109,500
Mill Street - Louisa St to George Street	34	$ 372,300
George Street - Mill Street to east end	36	$ 394,200
Edward Street - Mary to Collingwood	21	$ 229,950
Elizabeth Street West	16	$ 175,200
Caroline Street E&W - Mary Street - Sarah Street	28	$ 306,600
Collingwood Street - Wellington St. W to Louisa St	17	$ 186,150
Wellington Street West - Mill St to Collingwood St (heavy trees)	8	$ 87,600
Total	**194**	**$2,124,300**

Risks to Completion and Risk Mitigation: Material and labour resources available.

Comparative Information on Equivalent Historical Projects (if any): This is a discretionary program. Individual projects similar in scope to other pole line rebuild projects.

Renewable Energy Generation linkage: N/A

Non-distribution system options: N/A

B. Investment Evaluation Criteria	
Efficiency, Customer Value, Reliability	**Main Driver**: These projects are driven by the need to replace assets that have reached End-Of-Life status.
	Priority # 2022-2 through 10 – Discretionary projects.
	Investment effectiveness: Plant is replaced like-for-like or upgraded to as per plans for the area.
Safety	Poles at End-Of-Life represents a safety hazard to staff and the public. EOL status generally implies that pole structural strength has decreased to levels below the minimum acceptable per CSA Standard for Overhead construction. Replacement of EOL plant restores the system to safe structural and operating condition. Replacement plant to be installed in accordance with CSA construction standards and in compliance with ESA Reg. 22/04
Cyber Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Economic Development	N/A
Environmental benefits	N/A

C. Category-specific requirements: System Renewal	
Projects/activities in this category are driven by the relationship between the ability of an asset or asset system to continue to perform at an acceptable standard on a predictable basis on one hand and on the other, the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. "failure").	
Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure 1. Condition of Asset vs. Typical Life Cycle and Performance Record 2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure 3. Quantitative Customer Impacts (frequency or duration of interruptions and associated Risk level) 4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated Risk level) 5. Value of Customer Impact (high, medium, low)	1. Asset at EOL have reached the end of their life cycle. Future satisfactory performance in doubt. 2. Varies – 44kV pole failure may interrupt power to multiple MS depending on failure location. 3000+ customers may be impacted. 4.16kV pole failure may interrupt 500+ customers 3. Pole failure (multiple) could result in major interruption of 12-18 hours. 4. Reduced Risk of major outages will maintain customer satisfaction. 5. Customer surveys show that reliability is ranked high in value to them
Factors that may affect the timing of the proposed project, including the rate at which assets are replaced over the forecast period (i.e. investment intensity), where applicable;	CPC have the resources and materials in order to ensure project completion on time. Locates required from others.
Consequences for system O&M costs, including the implications for system O&M of	N/A – EOL equipment may fail unexpectedly and result in higher replacement costs (overtime, etc.) and higher

not implementing the project	outage costs to customers due to extended duration of unplanned outage
Reliability and or safety factors	New poles will be installed per CSA and 22/04 standards
Analysis of Project Benefits and Costs with alternative timing, expenditure, mitigation comparisons	Value/Risk result: 3.425 N/A – deferral increases Risk of unexpected failure; other alternatives (i.e. undergrounding) more expensive.
Analysis of Project Benefits and Cost for extra cost “like for like”. (System Access, System Service, General Plant benefit) (if applicable)	Pole class and loading design may be upgraded to coincide with plans for the area.
Other related information	Multi-year program to replace entire sections of pole line that have been assessed to be in “very poor”/”poor” condition. Complements the Planned pole replacement project.

Collus PowerStream Capital Project

2022

Project Name:	**Replace vehicle 11-15 – ½ Ton pickup Truck**			
Project #:				
Investment Category:	**General Plant**			
Investment Type:	**Discretionary**			
Service Area:	**Collingwood**			
Start Date:	**January 1, 2019**	**In Service Date:**	**December 31, 2019**	
Net Capital Cost: $50,000		**Gross Capital Cost:**	**$50,000**	
		Contributed Capital:	**$0**	
		OM&A Costs:	**$0**	
Expenditure Timing:	**Q1 $0**	**Q2 $0**	**Q3 $50,000**	**Q4 $0**

A. General Information:

A ½ ton pickup truck is to be procured to replace existing 1/2 ton pickup truck #11-15 which has been assessed to be at economic end-of –life by 2022. Existing truck #11-15 will be 7 years old by 2022 and will have well over 125,000 km of wear. Repairs and maintenance costs are expected to increase with continued operation and vehicle body deterioration. New vehicle will have reduced repair and maintenance costs.

Risks to Completion and Risk Mitigation: Delivery subject to manufacturer schedule.

Comparative Information on Equivalent Historical Projects (if any): Existing vehicle procured in 2015 at a cost of $39,000

Renewable Energy Generation linkage: N/A

Non-distribution system options: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver:** Replacement of aging fleet assets.
	Priority # 2022-11 - Discretionary project priority determined through the CPC capital prioritization process
	Investment effectiveness: The proposed fleet vehicle for replacement has reached the end of economic useful life. Reduced operating and maintenance expenses are expected.
Safety	The replaced vehicles will be matched to the work requirements and will reduce the Risk of improper work methods. The timing for fleet replacement ensures that vehicles are replaced before they deteriorate to a degree that represents an operational safety hazard.
Cyber Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Economic Development	N/A
Environmental benefits	N/A

C. Category-specific requirements: General Plant	
Projects/activities in this category are driven by the distributor's evolving requirements for capital to support day to day business and operations activities.	
Project Analysis - Value Assessment -include monetary benefit, if applicable	Value matrix assessment: Safety goal linkage = Medium Reliability goal linkage = Low Customer goal linkage = Low Finance goal linkage = Low
Project Analysis - Risk Assessment -impact of "do nothing" scenario -include monetary consequence, if applicable	Risk matrix assessment (1 year deferral Risk): Safety goal linkage = Negligible Reliability goal linkage = Negligible Customer goal linkage = Negligible Finance goal linkage = Negligible Potential for increased maintenance and fuel costs; reduced reliability
High cost material projects business case details (>$250k)	See attached business case
Other related information	N/A

Vehicle Replacement Assessment Guidelines[1]

Assessment Year	2016
Unit #	11-15
Year	2015
Description	Ford F150 - 1/2 Ton Pickup
Classification	Light
Original Cost	$39,114.51
Mileage	18672
Engine Hours	1604

Variable	Point Allocation	Performance factors	Points	2017	2018	2019	2020	2021	2022	2023
Age	1 point for each year of age	x years	1	2	3	4	5	6	7	8
Kilometers	1 point for each 25,000 km of use	xxxxx km	1	1	2	3	4	4	5	6
Engine Hours	1 point for each equivalent 25,000km of use (1 engine hour ~ 50km)	x hrs	3	6	10	13	16	19	22	26
Type of Service (duties or driving conditions)	1, 3 or 5 points based on type of service (ie harsh/offroad = 5; paved/daily use = 3; paved/non-daily use = 1)		3	3	3	3	3	3	3	3
Reliability	1, 3 or 5 points depending on frequency that vehicle is in shops for repair (ie. 2-3x/month = 5; 1x/3 months = 1)		1	1	1	1	1	1	1	1
Maintenance and Repair Costs	1, 3 or 5 points based on total life costs. (ie. lifetime costs > original vehicle cost = 5; lifetime costs <20% original vehicle cost = 1)		1	1	1	1	2	2	2	2
Condition	1, 3 or 5 points based on body condition, rust, interior condition, accident history , anticipated repairs,etc. (ie.		1	1	1	1	2	2	2	2
Other	1 - 5 points for any other condition criteria not covered above		1	1	1	1	1	1	1	1
	Total Points		**11.95**	**16.91**	**21.86**	**26.82**	**33.77**	**38.73**	**43.68**	**48.64**

Points evaluation	Light	Heavy
Very Good Condition	<20 pts	<18 pts
Good Condition	20 - 24 pts	18 - 22 pts
Fair Condition	24 - 29 pts	23 - 28 pts
Replacement condition	30+ points	29+ points

Condition Assessment **12**

Notes

Assessed by: xxxxxxxxx,Title

Date

Note 1 - Adapted from Guide to Vehicle Replacement and Right Sizing - Saskatchewan Ministry of Government Services

Note 2 - Box shade "red" - Replace; Box shade "yellow" - Fair; Box shade "green" - Good or Very Good

Collus PowerStream Capital Project

2022

Project Name:	**Replace vehicle 32-13 – ½ Ton pickup Truck**			
Project #:				
Investment Category:	**General Plant**			
Investment Type:	**Discretionary**			
Service Area:	**Collingwood**			
Start Date:	**January 1, 2022**	**In Service Date:**	**December 31, 2022**	
Net Capital Cost: $50,000		**Gross Capital Cost:**	**$50,000**	
		Contributed Capital:	**$0**	
		OM&A Costs:	**$0**	
Expenditure Timing:	**Q1 $0**	**Q2 $0**	**Q3 $50,000**	**Q4 $0**

A. General Information:

A ½ ton pickup truck is to be procured to replace existing ½ ton pickup truck #32-13 which has been assessed to be at economic end-of –life by 2022. Existing truck #32-13 will be 9 years old by 2022 and will have well over 175,000 km of wear. Repairs and maintenance costs are expected to increase with continued operation and vehicle body deterioration. New vehicle will have reduced repair and maintenance costs.

Risks to Completion and Risk Mitigation: Delivery subject to manufacturer schedule.

Comparative Information on Equivalent Historical Projects (if any): Existing vehicle procured in 2013 at a cost of $26,000

Renewable Energy Generation linkage: N/A

Non-distribution system options: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver:** Replacement of aging fleet assets.
	Priority # 2022-12 - Discretionary project priority determined through the CPC capital prioritization process
	Investment effectiveness: The proposed fleet vehicle for replacement has reached the end of economic useful life. Reduced operating and maintenance expenses are expected.
Safety	The replaced vehicles will be matched to the work requirements and will reduce the Risk of improper work methods. The timing for fleet replacement ensures that vehicles are replaced before they deteriorate to a degree that represents an operational safety hazard.
Cyber Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Economic Development	N/A
Environmental benefits	N/A

C. Category-specific requirements: General Plant	
Projects/activities in this category are driven by the distributor's evolving requirements for capital to support day to day business and operations activities.	
Project Analysis - Value Assessment -include monetary benefit, if applicable	Value matrix assessment: Safety goal linkage = Medium Reliability goal linkage = Low Customer goal linkage = Low Finance goal linkage = Low
Project Analysis - Risk Assessment -impact of "do nothing" scenario -include monetary consequence, if applicable	Risk matrix assessment (1 year deferral Risk): Safety goal linkage = Negligible Reliability goal linkage = Negligible Customer goal linkage = Negligible Finance goal linkage = Negligible Potential for increased maintenance and fuel costs; reduced reliability
High cost material projects business case details (>$250k)	See attached business case
Other related information	N/A

Vehicle Replacement Assessment Guidelines[1]

Assessment Year	2016
Unit #	32-13
Year	2013
Description	Dodge - 1/2 Ton Pickup
Classification	Light
Original Cost	$26,301.42
Mileage	63787
Engine Hours	1582

Variable	Point Allocation	Performance factors	Points	2017	2018	2019	2020	2021
Age	1 point for each year of age	x years	3	4	5	6	7	8
Kilometers	1 point for each 25,000 km of use	xxxxx km	3	3	4	5	6	7
Engine Hours	1 point for each equivalent 25,000km of use (1 engine hour ~ 50km)	x hrs	3	4	5	6	7	8
Type of Service (duties or driving conditions)	1, 3 or 5 points based on type of service (ie harsh/offroad = 5; paved/daily use = 3; paved/non-daily use = 1)		3	3	3	3	3	3
Reliability	1, 3 or 5 points depending on frequency that vehicle is in shops for repair (ie. 2-3x/month = 5; 1x/3 months = 1)		1	1	1	1	1	1
Maintenance and Repair Costs	1, 3 or 5 points based on total life costs. (ie. lifetime costs > original vehicle cost = 5; lifetime costs <20% original vehicle cost = 1)		1	1	1	1	1	1
Condition	1, 3 or 5 points based on body condition, rust, interior condition, accident history , anticipated repairs,etc. (ie.		1	1	1	1	2	2
Other	1 - 5 points for any other condition criteria not covered above		1	1	1	1	1	1
	Total Points		**15.72**	**18.62**	**21.53**	**24.43**	**28.34**	**31.24**

Points evaluation	Light	Heavy
Very Good Condition	<20 pts	<18 pts
Good Condition	20 - 24 pts	18 - 22 pts
Fair Condition	24 - 29 pts	23 - 28 pts
Replacement condition	30+ points	29+ points

Condition Assessment **16**

Notes

Assessed by: xxxxxxxxx,Title

Date

Note 1 - Adapted from Guide to Vehicle Replacement and Right Sizing - Saskatchewan Ministry of Government Services

Note 2 - Box shade "red" - Replace; Box shade "yellow " - Fair; Box shade "green" - Good or Very Good

Collus PowerStream Capital Project

2022

Project Name:	**Replace vehicle 36-06 – Passenger van**			
Project #:				
Investment Category:	**General Plant**			
Investment Type:	**Discretionary**			
Service Area:	**Collingwood**			
Start Date:	**January 1, 2022**	**In Service Date:**	**December 31, 2022**	
Net Capital Cost: $35,000		**Gross Capital Cost:**	**$35,000**	
		Contributed Capital:	**$0**	
		OM&A Costs:	**$0**	
Expenditure Timing:	**Q1** **$0**	**Q2** **$0**	**Q3** **$35,000**	**Q4** **$0**

A. General Information:

A new passenger van is to be procured to replace existing passenger van 36-06 which has been assessed to be at economic end-of –life by 2022. Existing truck #36-06 will be 16 years old by 2022 and will have well over 100,000 km of wear. Repairs and maintenance costs are expected to increase with continued operation and vehicle body deterioration. New vehicle will have reduced repair and maintenance costs.

Risks to Completion and Risk Mitigation: Delivery subject to manufacturer schedule.

Comparative Information on Equivalent Historical Projects (if any): Existing vehicle procured used from Town of Collingwood at a cost of $2,600.

Renewable Energy Generation linkage: N/A

Non-distribution system options: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver:** Replacement of aging fleet assets.
	Priority # 2022-13 - Discretionary project priority determined through the CPC capital prioritization process
	Investment effectiveness: The proposed fleet vehicle for replacement has reached the end of economic useful life. Reduced operating and maintenance expenses are expected .
Safety	The replaced vehicles will be matched to the work requirements and will reduce the Risk of improper work methods. The timing for fleet replacement ensures that vehicles are replaced before they deteriorate to a degree that represents an operational safety hazard.
Cyber Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Economic Development	N/A
Environmental benefits	N/A

C. Category-specific requirements: General Plant	
Projects/activities in this category are driven by the distributor's evolving requirements for capital to support day to day business and operations activities.	
Project Analysis - Value Assessment -include monetary benefit, if applicable	Value matrix assessment: Safety goal linkage = Medium Finance goal linkage = Low
Project Analysis - Risk Assessment -impact of "do nothing" scenario -include monetary consequence, if applicable	Risk matrix assessment (1 year deferral Risk): Safety goal linkage = Negligible Finance goal linkage = Negligible Potential for increased maintenance and fuel costs
High cost material projects business case details (>$250k)	See attached business case
Other related information	N/A

Vehicle Replacement Assessment Guidelines[1]

Assessment Year	2016
Unit #	36-06
Year	2006
Description	Dodge Caravan - Passenger
Classification	Light
Original Cost	$2,655.32
Mileage	69787
Engine Hours	503

Variable	Point Allocation	Performance factors	Points	2017	2018	2019	2020	2021	2022
Age	1 point for each year of age	x years	10	11	12	13	14	15	16
Kilometers	1 point for each 25,000 km of use	xxxxx km	3	3	3	4	4	4	4
Engine Hours	1 point for each equivalent 25,000km of use (1 engine hour ~ 50km)	x hrs	1	1	1	1	1	2	2
Type of Service (duties or driving conditions)	1, 3 or 5 points based on type of service (ie harsh/offroad = 5; paved/daily use = 3; paved/non-daily use = 1)		3	3	3	3	3	3	3
Reliability	1, 3 or 5 points depending on frequency that vehicle is in shops for repair (ie. 2-3x/month = 5; 1x/3 months = 1)		1	1	1	1	1	1	1
Maintenance and Repair Costs	1, 3 or 5 points based on total life costs. (ie. lifetime costs > original vehicle cost = 5; lifetime costs <20% original vehicle cost = 1)		1	1	1	1	1	1	1
Condition	1, 3 or 5 points based on body condition, rust, interior condition, accident history , anticipated repairs,etc. (ie.		2	1	1	1	2	2	2
Other	1 - 5 points for any other condition criteria not covered above		1	1	1	1	1	1	1
	Total Points		**21.8**	**22.18**	**23.56**	**24.94**	**27.32**	**28.70**	**30.08**

Points evaluation	Light	Heavy
Very Good Condition	<20 pts	<18 pts
Good Condition	20 - 24 pts	18 - 22 pts
Fair Condition	24 - 29 pts	23 - 28 pts
Replacement condition	30+ points	29+ points

Condition Assessment **22**

Notes

Assessed by: xxxxxxxxx,Title

Date

Note 1 - Adapted from Guide to Vehicle Replacement and Right Sizing - Saskatchewan Ministry of Government Services

Note 2 - Box shade "red" - Replace; Box shade "yellow" - Fair; Box shade "green" - Good or Very Good

Appendices

Appendix A

Policy and Procedure Manual		
Section: Corporate		**Policy #:** A-01
Policy: Asset Management		
Reviewed by: Ed Houghton, President & CEO	**Approved by:** David McFadden	
Date: March 1, 2016	**Revision Date:** N/A	**Page:** Page 1 of 1

Purpose:

Collingwood PowerStream Utility Services Corp. (CPUSC) is committed to delivering safe and reliable services to its customers in a financially and operationally effective manner. CPUSC utilizes its distribution system assets to deliver services in its service area. The distribution system assets are capital-intensive and have very long lives. Providing good quality, valued, reliable and sustainable services depends on having the distribution system assets in good condition. CPUSC has developed an asset management policy to ensure a continual and consistent focus on delivering services in a way that balances risk and long-term costs. The policy establishes the core asset management principles that drive CPUSC's planning framework.

Policy:

It is CPUSC policy that the distribution system shall be designed, procured, constructed, operated, maintained, renewed and retired in an efficient manner that:

- ✓ Supports CPUSC's corporate goals and asset management objectives;
- ✓ Supports the OEB's RRFE outcomes;
- ✓ Implements CPUSC's investment plan as documented in the Distribution System Planning Report;
- ✓ Complies with regulatory and statutory requirements
  - Health and safety of workers and the public;
  - Electricity supply quality and reliability;
  - Environmental Protection;
  - Good Utility Practice;
  - Financial and IFRS accounting practice; and
- ✓ Effectively controls and balances service levels with asset lifecycle costs and risks as well as reconciles with CPUSC's investment strategies and financing capabilities.

It is the responsibility of the CPUSC Board to ensure there are established roles, responsibilities, authorities and controls to achieve the asset management policy, strategy, objectives and plans. Responsibility for asset management is held from the Board to the President and CEO of CPUSC.

The President & CEO has overall responsibility for developing CPUSC's Asset Management System and reporting on the status and effectiveness of CPUSC's Asset Management System.

March 14, 2016

David McFadden, Chair   Date Signed

Appendix B

Substation Inspection Form

Substation		Date of Inspection		
File Number		Ambient Temp.		°C
Location				

Substation Visual Inspection

Mechanical Inspections		
Description of Inspection	*Status*	*Comments*
	OK/ FAIR/ POOR/ NA	
Tower Structure		
Insulators (Visual) Condition		
Fuses (Visual) Condition		
Metal Enclosed Switchgear Structure		
Identification Signs		
Warning Signs		
Yard Debris		
Weed Control		
Ground Connections on Tower		
Ground Connections on Metal Encl. Swgr.		
Ground Connections on Fence		
Ground Connections on Gates		
Ground Connections on Arresters		
Ground Connections on Transformer(s)		
Ground Grid & Rods Intact		
Gradient Mat		
Fence Assembly		
Barbed Wire		
Crushed Stone Depth		

Feeder Information

	Feeder 1	Feeder 2	Feeder 3	Feeder 4	Feeder 5	Feeder 6
Counter Reading						

Load Readings

	Phase A	Phase B	Phase C
Feeder 1			
Feeder 2			
Feeder 3			
Feeder 4			
Feeder 5			
Feeder 6			
Bus Voltage			

Collus PowerStream

Collus PowerStream - SCADA Department
RTU Maintenance/ Trouble Call Repair Log

RTU Type:______________________ Date:______________

Location ID: ______________________

Collingwood: ☐ Thornbury: ☐ Stayner: ☐ Creemore: ☐

Maintenance: ☐ Trouble Call: ☐ Station: ☐ Cabinet: ☐

Notes:

Maintenance Activity	Completed/ Pass	N/A	Follow-Up Required
Inspection of RTU cabinet/ Rack	☐	☐	☐
Inspection of cabling/ grounding	☐	☐	☐
Visual inspection of antenna	☐	☐	☐
Air clean RTU	☐	☐	☐
Clean rack or cabinet	☐	☐	☐
Replace ant traps in cabinet	☐	☐	☐
Test UPS	☐	☐	☐
Test heater/ thermostat	☐	☐	☐
Lubricate lock and hinges	☐	☐	☐
Radio RSSI (-50 to -80 dBm)	☐	☐	☐
Radio SNR (>24 dB)	☐	☐	☐

Follow-Up Notes:

Performed By:______________________

Created by Jeff Hansen, C.E.T.
Rev. 1.7

Appendix C

Connected Distributed Generation and Station Capacity

Model	TS Supply	Station	Feeder	Voltage	Peak kW	DG Capacity KWs	Connected DG kW	# Of Connections
Collingwood	Stayner TS M3	MS1	F1	4.16kV	1160	81.2	15.2	2
Collingwood	Stayner TS M3	MS1	F2	4.16kV	359	25.13		
Collingwood	Stayner TS M3	MS1	F3	4.16kV	1366	95.62		
Collingwood	Stayner TS M3	MS1	F4	4.16kV	970	67.9	18.06	2
Collingwood	Stayner TS M3	MS1	F5	4.16kV	1155	80.85	10	1
Collingwood	Stayner TS M3	MS2	F1	4.16kV	910	63.7		
Collingwood	Stayner TS M3	MS2	F2	4.16kV	310	21.7	3.4	1
Collingwood	Stayner TS M3	MS2	F3	4.16kV	1322	92.54	20.75	4
Collingwood	Stayner TS M3	MS2	F4	4.16kV	951	66.57		
Collingwood	Stayner TS M3	MS2	F5	4.16kV	994	69.58		
Collingwood	Stayner TS M3	MS3	F1	4.16kV	990	69.3	52.4	2
Collingwood	Stayner TS M3	MS3	F2	4.16kV	715	50.05	8.6	1
Collingwood	Stayner TS M3	MS3	F3	4.16kV	1421	99.47	20	3
Collingwood	Stayner TS M3	MS4	F1	4.16kV	786	55.02		
Collingwood	Stayner TS M3	MS4	F2	4.16kV	2173	152.11	78.225	2
Collingwood	Stayner TS M3	MS4	F3	4.16kV	366	25.62	10	1
Collingwood	Stayner TS M3	MS4	F4	4.16kV	1339	93.73	32	4
Collingwood	Stayner TS M8	MS5	F1	4.16kV	512	35.84	9	2
Collingwood	Stayner TS M8	MS5	F2	4.16kV	95	6.65		
Collingwood	Stayner TS M8	MS5	F3	4.16kV	2479	173.53	4.3	1
Collingwood	Stayner TS M8	MS5	F4	4.16kV	230	16.1	15.13	2
Collingwood	Stayner TS M3	MS6	F1	4.16kV	1450	101.5		
Collingwood	Stayner TS M3	MS6	F2	4.16kV	976	68.32		
Collingwood	Stayner TS M3	MS6	F3	4.16kV	782	54.74		
Collingwood	Stayner TS M3	MS6	F4	4.16kV	753	52.71	7.98	1
Collingwood	Stayner TS M3	MS6	F5	4.16kV	1043	73.01		
Collingwood	Stayner TS M8	MS7	F2	4.16kV	1465	102.55		
Collingwood	Stayner TS M8	MS7	F3	4.16kV	973	68.11		
Collingwood	Stayner TS M8	MS7	F5	4.16kV	335	23.45	10	1
Collingwood	Stayner TS M3	MS8	F1	4.16kV	707	49.49		
Collingwood	Stayner TS M3	MS8	F2	4.16kV	176	12.32		
Collingwood	Stayner TS M3	MS8	F3	4.16kV	666	46.62		
Collingwood	Stayner TS M3	MS8	F4	4.16kV	179	12.53		
Collingwood	Stayner TS M3	MS9	F2	4.16kV	1420	99.4	40	6
Collingwood	Stayner TS M3	MS9	F3	4.16kV	403	28.21		
Collingwood	Stayner TS M3	MS9	F5	4.16kV	371	25.97	8	1
Collingwood	Stayner TS M3	MS10	F1	4.16kV	167	11.69		
Collingwood	Stayner TS M3	MS10	F2	4.16kV	1623	113.61		
Collingwood	Stayner TS M8	H1 BB	F1	8.32kV		TBD by Hydro One		
Stayner	Stayner TS M5	MS1	F1	4.16kV	662	46.34	10	1
Stayner	Stayner TS M5	MS1	F2	4.16kV	688	48.16	20	2
Stayner	Stayner TS M5	MS1	F3	4.16kV	1511	105.77	8	2
Stayner	Stayner TS M2	MS2	F1	4.16kV	1057	73.99	20	2
Stayner	Stayner TS M2	MS2	F2	4.16kV	1122	78.54	17	2
Stayner	Stayner TS M2	MS2	F3	4.16kV	473	33.11		
Creemore	Stayner TS M2	H1 CREE DS	F2	8.32kV	2420	169.4	44.88	5
Thornbury	Meaford TS M2	MS1	F1	8.32kV	1220	85.4	120	1
Thornbury	Meaford TS M2	MS1	F2	8.32kV	390	27.3		
Thornbury	Meaford TS M2	MS1	F5	8.32kV	1077	75.39		
Thornbury	Meaford TS M2	MS2	F1	8.32kV	389	27.23		
Thornbury	Meaford TS M2	MS2	F2	8.32kV	649	45.43		
Thornbury	Meaford TS M2	MS2	F3	8.32kV	1102	77.14	6	1

		Collus Station DG Capacity							
								MS (HONI CALC)	
Model	TS Supply	Station	Feeder	Voltage	Max MVA	Min MVA	Peak	TX Size MVA	Capacity MVA
Collingwood	Stayner	MS1	F1	4.16kV	1276	510.4	Winter	6000	5804.4
Collingwood	Stayner	MS1	F2	4.16kV	394.9	157.96			
Collingwood	Stayner	MS1	F3	4.16kV	1502.6	601.04			
Collingwood	Stayner	MS1	F4	4.16kV	1067	426.8			
Collingwood	Stayner	MS1	F5	4.16kV	1270.5	508.2			
Collingwood	Stayner	MS2	F1	4.16kV	1001	400.4	Summer	8000	6774.28
Collingwood	Stayner	MS2	F2	4.16kV	341	136.4			
Collingwood	Stayner	MS2	F3	4.16kV	1454.2	581.68			
Collingwood	Stayner	MS2	F4	4.16kV	1046.1	418.44			
Collingwood	Stayner	MS2	F5	4.16kV	1093.4	437.36			
Collingwood	Stayner	MS3	F1	4.16kV	1089	435.6	Winter	3000	3175.44
Collingwood	Stayner	MS3	F2	4.16kV	786.5	314.6			
Collingwood	Stayner	MS3	F3	4.16kV	1563.1	625.24			
Collingwood	Stayner	MS4	F1	4.16kV	864.6	345.84	Winter	5000	5052.16
Collingwood	Stayner	MS4	F2	4.16kV	2390.3	956.12			
Collingwood	Stayner	MS4	F3	4.16kV	402.6	161.04			
Collingwood	Stayner	MS4	F4	4.16kV	1472.9	589.16			
Collingwood	Stayner	MS5	F1	4.16kV	563.2	225.28	Winter	10000	7420.76
Collingwood	Stayner	MS5	F2	4.16kV	39.6	15.84			
Collingwood	Stayner	MS5	F3	4.16kV	2726.9	1090.76			
Collingwood	Stayner	MS5	F4	4.16kV	222.2	88.88			
Collingwood	Stayner	MS6	F1	4.16kV	1595	638	Winter	6000	5801.76
Collingwood	Stayner	MS6	F2	4.16kV	1073.6	429.44			
Collingwood	Stayner	MS6	F3	4.16kV	860.2	344.08			
Collingwood	Stayner	MS6	F4	4.16kV	828.3	331.32			
Collingwood	Stayner	MS6	F5	4.16kV	1147.3	458.92			
Collingwood	Stayner	MS7	F2	4.16kV	1611.5	644.6	Summer	5000	4220.12
Collingwood	Stayner	MS7	F3	4.16kV	1070.3	428.12			
Collingwood	Stayner	MS7	F5	4.16kV	368.5	147.4			
Collingwood	Stayner	MS8	F1	4.16kV	777.7	311.08	Winter	4000	3160.32
Collingwood	Stayner	MS8	F2	4.16kV	193.6	77.44			
Collingwood	Stayner	MS8	F3	4.16kV	732.6	293.04			
Collingwood	Stayner	MS8	F4	4.16kV	196.9	78.76			
Collingwood	Stayner	MS9	F2	4.16kV	1562	624.8	Winter	10667	7202.32
Collingwood	Stayner	MS9	F3	4.16kV	443.3	177.32			
Collingwood	Stayner	MS9	F5	4.16kV	408.1	163.24			
Collingwood	Stayner	MS10	F1	4.16kV	183.7	73.48	Winter	6000	4387.6
Collingwood	Stayner	MS10	F2	4.16kV	1785.3	714.12			
Stayner	Stayner	MS1	F1	4.16kV	599.5	239.8	Winter	5000	3824.12
Stayner	Stayner	MS1	F2	4.16kV	756.8	302.72			
Stayner	Stayner	MS1	F3	4.16kV	704	281.6			

Appendix D

IESO/HONI Comment Letters

TO BE POSTED JUST PRIOR TO OEB SUBMISSION

Appendix E

2018 – 2022 Capital by G/L

CAPITAL EXPENSES

Account	Year	2017	2018	2019	2020	2021	2022
		Yearly Totals					
	Substation	$51,087	$51,087	$52,058	$53,047	$54,055	$55,082
1820	Station Equipment	$0	$0	$0	$0	$0	$0
1980	SCADA	$51,087	$51,087	$52,058	$53,047	$54,055	$55,082
1808	Buildings	$0	$0	$0	$0	$0	$0
1805	Land	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	$589,100	$997,755	$901,840	$1,049,540	$1,075,331	$1,177,878
1835	Overhead Conductor and Devices	$605,255	$1,025,117	$926,571	$1,078,322	$1,104,820	$1,210,179
1840	Underground Conduit	$352,831	$33,827	$281,966	$35,582	$36,457	$39,933
1845	Underground Conductor and Devices	$233,011	$22,551	$152,890	$23,722	$24,305	$26,622
1850	Line Transformer	$67,210	$65,211	$224,806	$68,595	$70,281	$76,983
1855	Services	$268,094	$26,009	$39,457	$27,359	$28,032	$30,705
1860	Meters	$139,533	$139,533	$142,184	$144,886	$147,638	$150,444
1915	Office Furniture and Equipment	$20,000	$20,000	$20,380	$20,767	$21,162	$21,564
1920/1925	Computer Hardware & Software	$100,000	$100,000	$101,900	$103,836	$105,809	$107,819
1930	Vehicles and Equipment	$475,000	$500,000	$210,000	$500,000	$425,000	$135,000
1940	Tools, Shop, and Garage Equipment	$31,334	$31,930	$32,536	$33,154	$33,784	$34,426
	TOTAL	$2,932,455	$3,013,020	$3,086,589	$3,138,811	$3,126,673	$3,066,635

CONTRIBUTED CAPITAL

	Year	2017	2018	2019	2020	2021	2022
		Yearly Totals					
	Customer Initiated	$475,000	$484,025	$493,221	$502,593	$512,142	$521,873
1835	Overhead Conductor and Devices	$122,500	$124,828	$127,199	$129,616	$132,079	$134,588
1850	Line Transformer	$140,000	$142,660	$145,371	$148,133	$150,947	$153,815
1840	Underground Conduit	$17,500	$17,833	$18,171	$18,517	$18,868	$19,227
1845	Underground Conductor and Devices	$70,000	$71,330	$72,685	$74,066	$75,474	$76,908
1855	Services	$125,000	$127,375	$129,795	$132,261	$134,774	$137,335
	Road Authority	$138,375	$141,005	$143,684	$146,414	$149,195	$152,030
1830	Poles, Towers and Fixtures	$63,611	$64,819	$66,051	$67,306	$68,584	$69,888
1835	Overhead Conductor and Devices	$65,355	$66,597	$67,862	$69,151	$70,465	$71,804
1840	Underground Conduit	$2,157	$2,198	$2,239	$2,282	$2,325	$2,369
1845	Underground Conductor and Devices	$1,438	$1,465	$1,493	$1,521	$1,550	$1,580
1850	Line Transformer	$4,157	$4,236	$4,317	$4,399	$4,483	$4,568
1855	Services	$1,658	$1,690	$1,722	$1,755	$1,788	$1,822
	Subtotal	$613,375	$625,030	$636,905	$649,006	$661,337	$673,903
2440	Contributed Capital	($449,875)	($458,423)	($467,133)	($476,008)	($485,052)	($494,268)
	Customer Initiated (85% Contributed)	$403,750	$411,421	$419,238	$427,204	$435,321	$443,592
	Road Authority (1/3 Contributed)	$46,125.12	$47,001.50	$47,894.53	$48,804.52	$49,731.81	$50,676.71
	TOTAL	$163,500	$166,607	$169,772	$172,998	$176,285	$179,634

NET CAPITAL

TOTAL	$3,095,955	$3,179,627	$3,256,361	$3,311,809	$3,302,958	$3,246,270