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August 28, 2019

Board Secretary
Ontario Energy Board
PO Box 2319
27th Floor 2300 Yonge Street
Toronto ON M4P 1E4

Attn: Kirsten Walli

RE: EPCOR Electricity Distribution Ontario Inc. *(formerly Collus PowerStream)* License ED-2002-0518 – Distribution System Plan

On August 14, 2018, EPCOR (under the name Collus PowerStream) received notice of approval of its 2019 cost of service rate application deferral request from the Board Secretary. As a condition of this approval, EPCOR was requested to submit an updated Distribution System Plan Document in the absence of a 2020 cost of service:

> *Collus PowerStream states in its deferral request letter that the corporation has completed a 2018 to 2022 Distribution System Plan. Subject to the outcome of the share transaction applications, the OEB will require Collus PowerStream to file an updated distribution system plan by August 30, 2019.*

In response to this request, please find attached EPCOR's 2019-2023 updated distribution system plan.

If you have any questions, please do not hesitate to contact the undersigned at lirwin@epcor.com or (705)445-1800 ext 2223.

Yours truly,

Larry Irwin
General Manager
EPCOR Electricity Distribution Ontario Inc.
Encl

EPCOR Electricity Distribution Ontario Inc.

2019 – 2023 Distribution System Plan

August 26, 2019 – Ver. 3.3

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Introduction

EPCOR Electricity Distribution Ontario Inc. ("EEDO") 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 EEDO'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. The original draft of the Distribution System Plan, for customer consultation purposes, covered the forecast 2018 – 2022 timeframe. This updated Distribution System Plan covers the 2019 – 2023 timeframe.

EPCOR Utilities Inc. ("EUI") is a corporation under the laws of the province of Alberta and is the parent company of EEDO a corporation incorporated under the laws of the province of Ontario.

EEDO is a corporation incorporated under the laws of the province of Ontario and is 100% owned by the EPCOR Utilities Inc. ("EUI"). EUI purchased the 100% interest of Collus PowerStream Corp. (CPC) on Oct 1, 2018 (MADD application (EB-2017-0373) approved by OEB August 30, 2018). Where information pertaining to EEDO activities prior to the purchase of CPC is stated, it is understood that these activities were performed under the CPC brand.

EEDO receives power from Hydro One 44kV feeders and as such is considered an embedded distributor. Revenue is earned by EEDO 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, 2018, EEDO served approximately 17,335 electricity distribution customers across its service area:

Service Connections	
Collingwood	13,157
Stayner	1,984
Thornbury	1,566
Creemore	648

The Town of Collingwood functions as the major commercial centre for northwest Simcoe County and northeast Grey County. It has been identified as a Primary Settlement Area in the Province's Places to Grow Act. 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.

EEDO is responsible for maintaining distribution and infrastructure assets deployed over 45 square kilometers (including 362 kilometers of overhead lines and underground lines).

EEDO'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.

EEDO's Distribution System Plan documents EEDO's asset management processes and capital expenditure plan for the 2019-2023 period. The Distribution System Plan documents the practices, policies and processes that are in-place to ensure that investment decisions support EEDO's desired outcomes in a cost-effective manner and provides value to the customer.

EEDO's Distribution System Plan is designed to support the achievement of the four key OEB established performance outcomes:

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

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

EEDO 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 EEDO 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 EEDO 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. EEDO 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.

EEDO 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.

EEDO'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

EEDO'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 EEDO's integrated approach to planning, prioritizing, managing assets and includes regional planning, local stakeholder consultations, renewable generation connections and smart grid considerations.

EEDO 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 EEDO is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via EEDO'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 EEDO's distribution system to provide customers with electricity services.

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

General plant - investments are modifications, replacements or additions to EEDO'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. EEDO'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 EEDO'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 EEDO has completed in the 2014 – 2018 historical period and the 2019 – 2023 forecast period.

As part of its planning process, EEDO has adopted a consistent capital budget envelope for the DSP period that balances annual mandatory System Access investments with non-mandatory needs in the other three investment categories through a project pacing and prioritization process. This is discussed further in section 5.3 of this DSP.

Individual capital investment category variation recognizes the specific impact of System Access work and other competing needs on the ability of EEDO to fund/do other work at the same time while keeping rates manageable. In this sense other non-mandatory work (i.e. System Renewal, System Service and General Plant) is prioritized, paced and managed to provide consistent yearly overall capital spends. While individual capital categories may vary from year to year, EEDO's overall Capital spend has been kept consistent over the DSP plan period to provide a steady and predictable impact on rates.

The following tables summarize the proposed capital investments (annual $ and % spend) within the four designated categories for the 2019 – 2023 period:

	2019	2020	2021	2022	2023
System Access	$ 311,957	$ 517,226	$ 353,820	$ 361,475	$ 390,582
System Renewal	$ 2,117,880	$ 2,449,813	$ 2,374,029	$ 2,881,046	$ 2,865,186
System Services	$ 300,000	$ 75,000	$ 76,875	$ 79,181	$ 81,161
General Plant	$ 569,210	$ 657,757	$ 585,755	$ 263,809	$ 567,904
Total	$ 3,299,047	$ 3,699,796	$ 3,390,479	$ 3,585,511	$ 3,904,833

	2019	2020	2021	2022	2023
System Access	9%	14%	10%	10%	10%
System Renewal	64%	66%	70%	80%	73%
System Services	9%	2%	2%	2%	2%
General Plant	17%	18%	17%	7%	15%
Total	100%	100%	100%	100%	100%

Table 1 – EEDO Capital Investment Summary 2019 - 2023

5.2.1 Distribution System Plan overview

5.2.1a Key elements of the Distribution System Plan

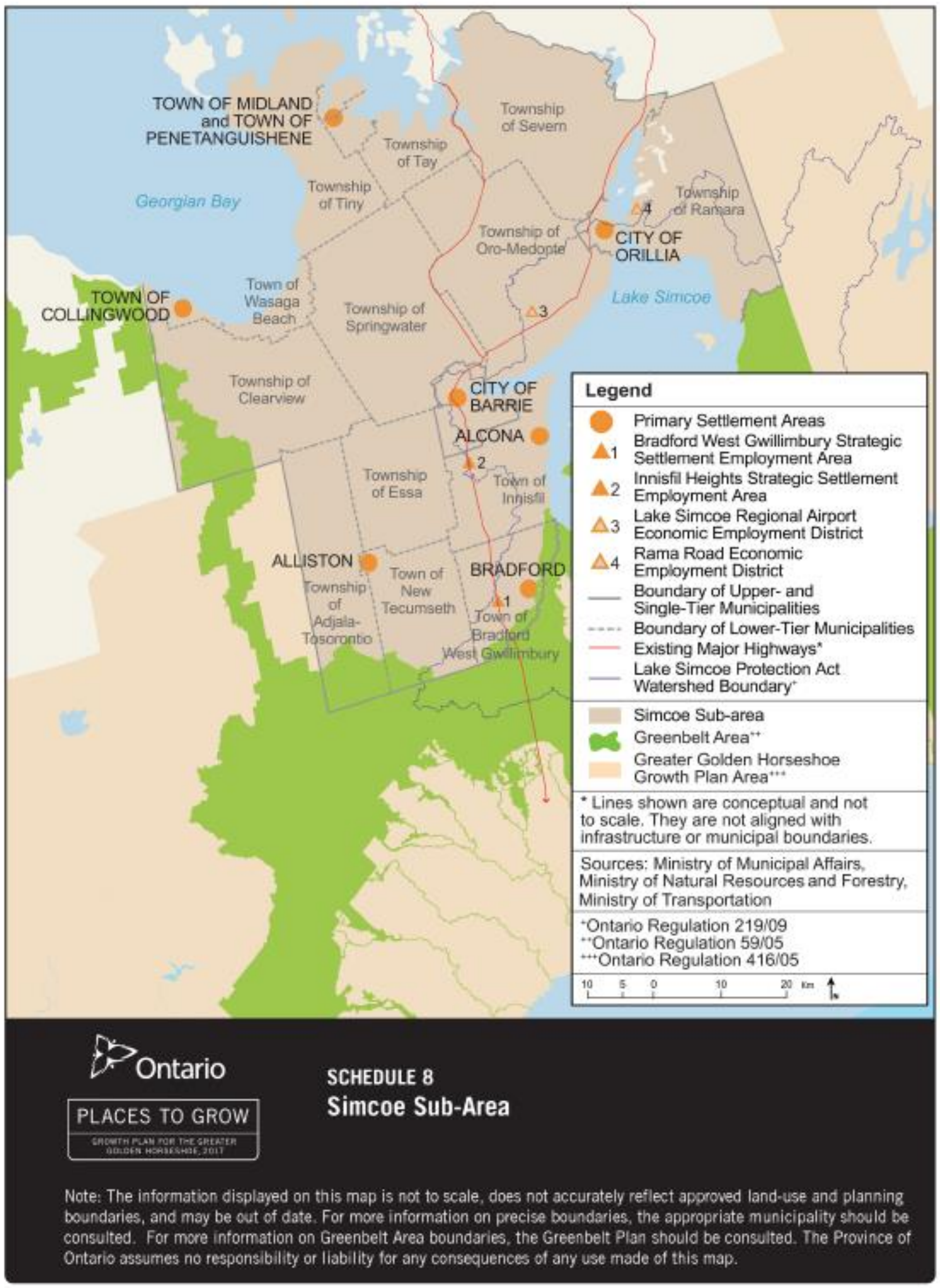
It is expected that the operational and service requirements driving EEDO's capital expenditures, and found within its DSP, will generally remain consistent through the 2019 to 2023 planning window. EEDO's net total capital expenditure over the planning period 2019 through 2023 is forecasted to be $17.9 million, which reflects average annual spends of $3.6 million in 2019 through 2023. The projected expenditures for 2019 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 EEDO's distribution system;
- System Service spending needs to facilitate the replacement of the SCADA system in 2019 and ongoing SCADA servicing needs through 2023;
- 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 2019 – 2023 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 (2005)/ Growth Plan for the Greater Golden Horseshoe Area (2017) The Growth Plan for the Greater Golden Horseshoe (2017) replaces the 2006 initial Growth Plan and came into effect July 1, 2017. The plan provides population and employment forecasts for the Greater Golden Horseshoe to 2041. Amendments to the Growth Plan in 2018 are not seen as affecting the impact of the 2017 plan on the DSP.

The Town of Collingwood has been identified as a Settlement Area in the Growth Plan for the Greater Golden Horseshoe Area. Growth will be directed to Settlement Areas to make better use of land and infrastructure. The Simcoe Sub-Area is specifically noted in the Growth Plan. It provides additional, more specific direction on how the Plan's vision will be achieved in the Simcoe Sub-area. It directs a significant portion of growth within the Simcoe Sub-area to communities where development can be most effectively serviced, and where growth improves the range of opportunities for people to live, work, and play in their communities, with a particular emphasis on Primary Settlement Areas. The Town of Collingwood is a Primary Settlement Area. See Figure 1 below:



Growth Plan for the Greater Golden Horseshoe | 105

Figure 1 – Simcoe Sub-Area Primary Settlement Areas

Growth directed to Settlement Areas has been identified in the Plan. The Town of Collingwood is projected to grow to a population of 33,400 and employment of 13,500 by the year 2031

Distribution of Population and Employment for the City of Barrie, City of Orillia and County of Simcoe to 2031

	POPULATION	EMPLOYMENT
City of Barrie	210,000	101,000
City of Orillia	41,000	21,000
Township of Adjala-Tosorontio	13,000	1,800
Town of Bradford West Gwillimbury	50,500	18,000
Township of Clearview	19,700	5,100
Town of Collingwood	33,400	13,500
Township of Essa	21,500	9,000
Town of Innisfil	56,000	13,100
Town of Midland	22,500	13,800
Town of New Tecumseth	56,000	26,500
Township of Oro-Medonte	27,000	6,000
Town of Penetanguishene	11,000	6,000
Township of Ramara	13,000	2,200
Township of Severn	17,000	4,400
Township of Springwater	24,000	5,600
Township of Tay	11,400	1,800
Township of Tiny	12,500	1,700
Town of Wasaga Beach	27,500	3,500
TOTAL SIMCOE SUB-AREA	667,000	254,000

Ontario

PLACES TO GROW

GROWTH PLAN FOR THE GREATER GOLDEN HORSESHOE, 2017

SCHEDULE 7

Distribution of Population and Employment for the City of Barrie, City of Orillia and County of Simcoe to 2031

Growth Plan for the Greater Golden Horseshoe | 103

Figure 2 – County of Simcoe Growth Projections

DSP impact: The population and employment growth presented in the Growth Plan will likely require capital investment to provide for new connections and capacity including timely acquisition of property for future substation needs. This will likely require investment in the System Access and System Service categories. Specific growth scenarios details will be obtained from County and Town Official Plans.

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 33,400 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.

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

Town of Collingwood Official Plan (Consolidated January 2019)

The Town of Collingwood Official Plan establishes the general pattern and quantifies future growth to the year 2031. Its purpose is to ensure the best form of development under the most desirable conditions.

The Official Plan is based upon a series of detailed planning, environmental, economic and servicing studies commissioned by the Town of Collingwood, as well as comments received from the general public, the County of Simcoe and other municipalities, County and Provincial Ministries, agencies and departments. The background studies, which preceded the adoption of the updated Official Plan focused on Collingwood's natural environment, servicing and transportation circumstances, and residential, commercial, industrial and recreational land needs.

DSP impact: System Access needs for new connections are expected to remain steady over the forecast period. Growth will likely require capital investment to provide for new connections and to ensure sufficient capacity to facilitate proper system operation i.e. feeder and station maintenance. It is not anticipated that growth will have a significant impact on System Service and General Plant needs over the forecast period.

Town of Collingwood Road Projects – The Town of Collingwood has ongoing road rehabilitation and widening projects some of which may require the relocation of EEDO plant. Information is provided for only the 2019 year of the DSP forecast period.

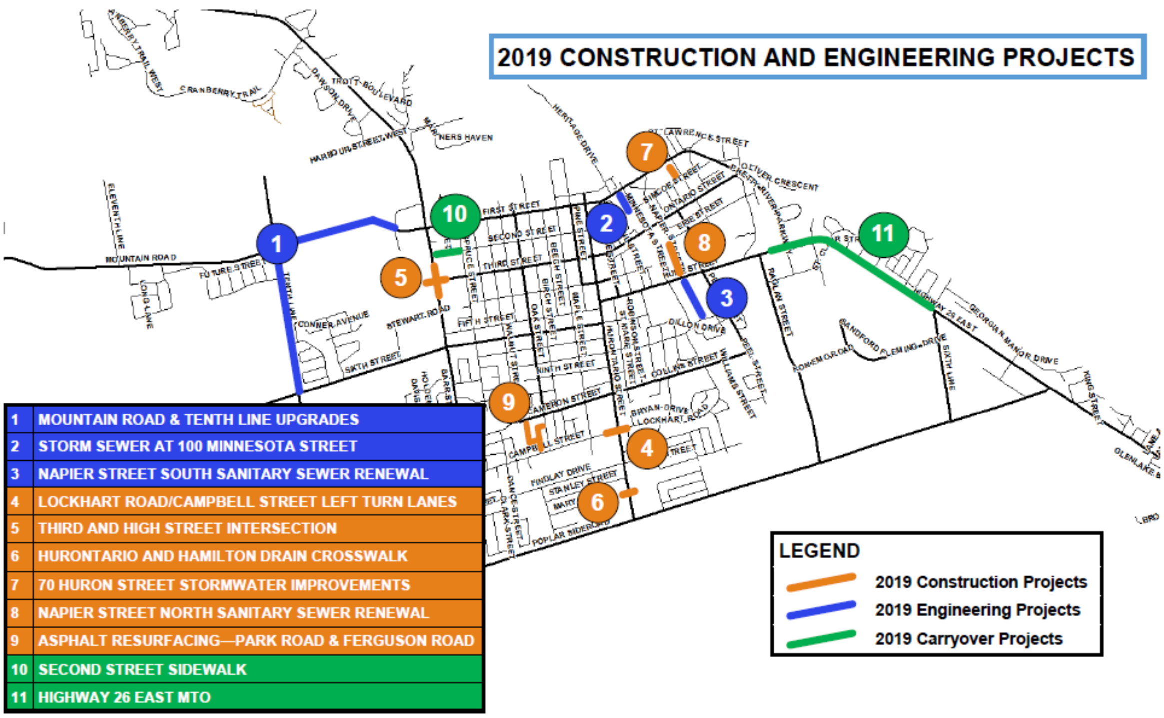


Figure 3 – Future Construction Projects – Town of Collingwood

DSP Impact: Any EEDO plant relocation required as a result of forecast road works have been incorporated into the DSP. Future additions to the road construction schedule, within the period of the DSP, may require reallocation of resources to System Access spending from other capital investments.

Simcoe County Road Projects – Simcoe County has not identified any significant road construction projects within the EEDO service area (County of Simcoe GIS interactive maps). Future additions to the road construction schedule affecting EEDO plant, within the period of the DSP, may require reallocation of resources to System Access spending from other capital investments.

DSP Impact: None

Southern Georgian Bay/Muskoka Region Supply Study - EEDO is in Group 2 - Southern Georgian Bay/Muskoka region. Study recommendations will not impact EEDO 2019 – 2023 planning investments.

DSP impacts: None

County of Simcoe Official Plan (2008 – updated 2016) - 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, 2017				
	2016-2031			
Growth Plan Policy Area	Schedule 7 *Population Growth*	Demand *Housing Units Needed*	Supply *Unit Potential*	Difference *Potential Unit Surplus at 2031*
Delineated Built Boundaries and Undelineated Built-Up Areas	5,246	2,486	4,008	1,522
Designated Greenfield Areas	8,913	3,729	5,506	1,777
Outside Settlement Areas	-	-	-	-
Municipal-wide	14,159	6,215	9,514	**3,298**
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

DSP Impact: Information in the Simcoe Official Plan complements the information and DSP impact from the Town of Collingwood Official plan.

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 (20 % since 2006) has been 2x the provincial average which makes it one of the top 10 locations to open a small business in Ontario.

DSP impact: Moderate growth in General Service operations is expected to mitigate the need for System Service investments over the DSP forecast period. No new stations or feeder extensions are required

End of life Assets – EEDO 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.

DSP Impact: It is recognized that System Renewal investments are non-mandatory and annual program spending is a trade-off between the risk of outages due to equipment failure and maintaining current levels of reliability. In this DSP, System Renewal spending is paced throughout the forecast period of the DSP to accommodate annual spending variances in the other investment categories to maintain overall budget envelope spending while continuing the progress of replacing end of life assets in a timely and cost-effective manner that EEDO believes will maintain current levels of reliability. In general System Renewal spending is expected to increase compared to historical levels.

5.2.1b Consideration of Customer preferences and expectations

EEDO has used information obtained through consultations with customers and other stakeholders (i.e. town government, IESO, developers, etc.) to plan and pace expenditures as evenly as possible over the forecast period, while ensuring the investments address customers preferences and expectations. EEDO 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.

EEDO has used customer surveys to provide a high-level assessment of customer preferences. Survey results indicate satisfaction with current service performance levels. Customer concern about the overall cost of electricity supports the need to consider rate mitigation efforts while managing risk and smoothing spending over time for non-mandatory investments necessary to maintain current service performance levels.

Survey results are implicitly considered in the development of the asset management strategy, objectives and initial stages of annual plan development. Surveys indicate that cost of power and maintaining reliability are key issues of interest to the customer. This supports EEDO's position on proactive system renewal related planned replacement programs for key assets at end of life such that current reliability levels are maintained.

It is understood that EEDO's rate mitigation efforts will only impact less than 20% of the customer's bill, the other 80% being out of EEDO's control.

DSP Impact: Once mandatory investments (i.e. System Access) were budgeted and scheduled within the DSP forecast period, non-mandatory investments were assessed, prioritized and scheduled within the DSP forecast period with a leading emphasis on System Renewal in order to maintain current service levels as guided by customer preference feedback.

5.2.1c Sources of cost savings

EEDO 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 EEDO 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 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 EEDO'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.
- EEDO has attained efficiencies by the pooling of resources and building a strong knowledge based environment, primarily from its involvement with two co-operative organizations – Cornerstone Hydro Electric Concepts Inc. (CHEC Group);; and the Utility Standards Forum (USF).
    - The CHEC Group is an association of 16 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 also provides back office support (Billing, Call Centre, Customer Information System (CIS), Hosting, Financial Information System, Resource Backup, & Document Storage Solution) through the UCS group. UCS owns the license for the Harris NorthStar electricity billing system used by EEDO. EEDO is one of 9 LDCs who work collaboratively through UCS on shared services 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 54 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.
    - The CHEC Group estimates that savings through pooling services amount to an average of $244,000 (2018) per LDC member annually.
- Meter services (settlements, MSP) are contracted out that result in cost-effective market-based rates for services provided.
- System Control Room and After-Hours Dispatch Services for 2019 are provided by Alectra Inc. through a Shared Service Agreement that result in cost-effective market-based rates for services provided.
- Mobile equipment (i.e. laptops/tablets) provides paperless access to EEDO 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 EEDO 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.

On an annual basis, each utility in Ontario is assigned an efficiency ranking based on its three-year average performance. To determine a ranking, electrical distributors are divided into five groups based on the magnitude of the difference between their actual costs and predicted costs. For 2013 and 2014, EEDO (formerly Collus PowerStream) was placed in Group 3 in terms of efficiency. Group 3 is considered average and is defined as having actual costs within +/- 10% of predicted costs. For 2015 to 2018, EEDO was placed in Group 2, in terms of efficiency. Group 2 is considered above average and is defined as having actual costs less than 10-25% of predicted costs.

EEDO achieved a three-year average for 2016 to 2018 of 17.0% (2015 to 2017 - 15.3%) less than predicted costs. The Corporations three-year average ranking has improved by 1.7%. For the 2018 year, the result was 19.3% (2017 - 18.4%) less than predicted costs, which is a 0.90% improvement. Our goal is to maintain our position within Group 2 into future years.

The table below summarizes the 2019 – 2023 activity savings.

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
CHEC Group pooled services	Average $244,000 savings annually
MSP contracted	Market competitive costs
Alectra Control Room services	Market competitive costs
Mobile equipment	Improved data quantity and quality effort
3rd party pole replacements	Cost sharing for pole replacement

Table 3 – 2019 – 2023 Activity savings

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

5.2.1d Period covered by the Distribution System Plan

For the purposes of this Distribution System Plan, 2014 to 2018 is the historical period and the forecast is for 2019 to 2023. 2018 is the bridge year and 2019 is the test year.

5.2.1e Vintage of the information

The information generally used throughout the DSP are based on available information established to late 2018 and should be considered as current. Specific variances from this are as noted. EEDO statistics based on 2018 RRR filings.

5.2.1f Important changes to EEDO asset management process

This is the first Distribution Plan officially filed by EEDO and as such there are no changes from any previously filed plan. Previous information with respect to EEDO's Asset Management processes, including the 2012 Asset Management Plan, was filed in EEDO's 2013 Cost of Service application. EEDO's 2018–2022 Draft Distribution Plan was made available via website posting as per OEB directive during 2018 MADD application process but not formally filed with the OEB.

Since EEDO'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 2019-2023 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.

5.2.1g Contingent activities/events affecting the Distribution System Plan

There are a number of ongoing and future activities in the EEDO 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 2019 – 2023 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. EEDO 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 2019 Capital Budget for road work. There is no information on post 2019 road works. EEDO will be required to react to road project work that affects the distribution plant, as it occurs during the period of the DSP.

<u>Meter reverification</u>

EEDO is required to have its residential type meters tested to ensure compliance with Measurement Canada standards. In 2019, approximately 3,000 of EEDO'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 (2019). The meter population will be tested in one group. 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 $450,000. The DSP assumes that the meters will successfully pass reverification testing.

All meter testing within the period of the DSP is summarized in the tables below:

Testing Year	Residential meters to be tested	Potential Replacement Cost	Non-Residential meters to be tested	Potential Replacement Cost
2019	3000	$450,000	245	$13,800
2020	1200	$150,000	0	$0
2021	800	$128,000	180	$11,400
2022	0	$0	0	$0
2023	2300	$391,000	37	$2,400

Table 4 – 2019 – 2023 Meter Reverification Testing

5.2.1h Grid modernization, DER and Climate Change investments

In 2019, EEDO will be replacing their legacy SCADA system with a new system. The C3-ilex SCADA system has reached end of life status. EEDO can no longer obtain software security updates or replacement hardware. Replacing the SCADA system will mitigate control/telemetry reliability risk for EEDO.

There are no specific investments over the period of the DSP required to connect distributed energy resources. Existing plant capacity deemed adequate to connect known plans for distributed energy resource in EEDO's service area.

There are no specific capital investments over the period of the DSP related to climate change adaptation that would harden and/or improve the resiliency of the distribution system. EEDO plant will continue to be installed according to the latest CSA, IEEE and industry standards. It is expected that climate change impacts will be incorporated into the ongoing evolution of construction and material standards. From an operating perspective, EEDO has enhanced its preventative maintenance practices in the area of vegetation management to mitigate the impacts of severe wind and storm events. The tree trimming program has been set at a 3-year cycle to minimize outage impacts due to severe weather-related vegetation contact with overhead lines.

Where and when required, EEDO will pursue cost-effective and efficient grid modernization, DER and climate change related investments as emphasized in the Long-Term Energy Plan.

5.2.2 Coordinated Planning with third parties

5.2.2a Description of the consultations

Table 5 provides a brief summary of the various consultations that EEDO participates in during the year. Details regarding the deliverables and impact to the DSP are provided in the noted references and discussion following:

Purpose of Consultation	Initiator	Other Participants	Deliverables –Scope and Timing	Impact on DSP
Regional Planning	IESO	IESO, HONI, South Georgian Bay/Muskoka Region LDCs	IRRPs issued December 2016; RIP issued August 2017	No impact on DSP
Customer consultations to provide advice and obtain feedback	EEDO	Customers, HONI, Alectra	CDM, DG program facilitation; customer satisfaction survey	Customer survey preferences are integral part of DSP
Overhead plant locations approval on roadways	EEDO	Towns of Collingwood, Staynor, Thornbury, Creemore, Simcoe County	Town or Region/County approval of proposed EEDO overhead plant location on road allowance	No specific impact on DSP
Road authority work schedule coordination	EEDO	Towns of Collingwood, Staynor, Thornbury, Creemore, Simcoe County	Determination of timing and scope of road authority work that may impact existing EEDO plant	No specific impact on DSP
DG Planning	EEDO	IESO, HONI, other LDCs	No REG investments planned	No specific impact on DSP.
Other utility consultations	EEDO	CHEC group, HONI	2 – 4 meetings annually to discuss items of mutual interest	No specific impact on DSP
Town of Collingwood Emergency Plan	Town	EEDO	Annual training exercise	No specific impact on DSP

Table 5 - Consultation Summary

<u>Regional Planning - Southern Georgian Bay/Muskoka region</u>

EEDO 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.
- Newmarket-Tay Power Distribution Ltd.
- Orangeville Hydro Limited
- Orillia Power Distribution Corporation
- Parry Sound Power Corp.

• Alectra Inc. (Barrie)

• Elexicon Energy

• Wasaga Distribution Inc.

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, EEDO provided its load forecasts for its service area to Hydro One for incorporation into the Needs Assessment process. The load forecast show that EEDO is winter peaking. The load forecasts for winter and summer are shown in section 5.2.2c.

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 would require regional coordinated planning. Two Working Groups were established to undertake Integrated Regional Resource Plans (IRRP) for each sub-region to address the needs in these areas. EEDO 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 EEDO. EEDO took no further part in the IRRP process.

The IRRPs were completed and issued in December 2016. The Hydro One Regional Infrastructure Plan (RIP) was issued in August 2017. The IRRPs and RIP have no impact on the 2019 – 2023 DSP.

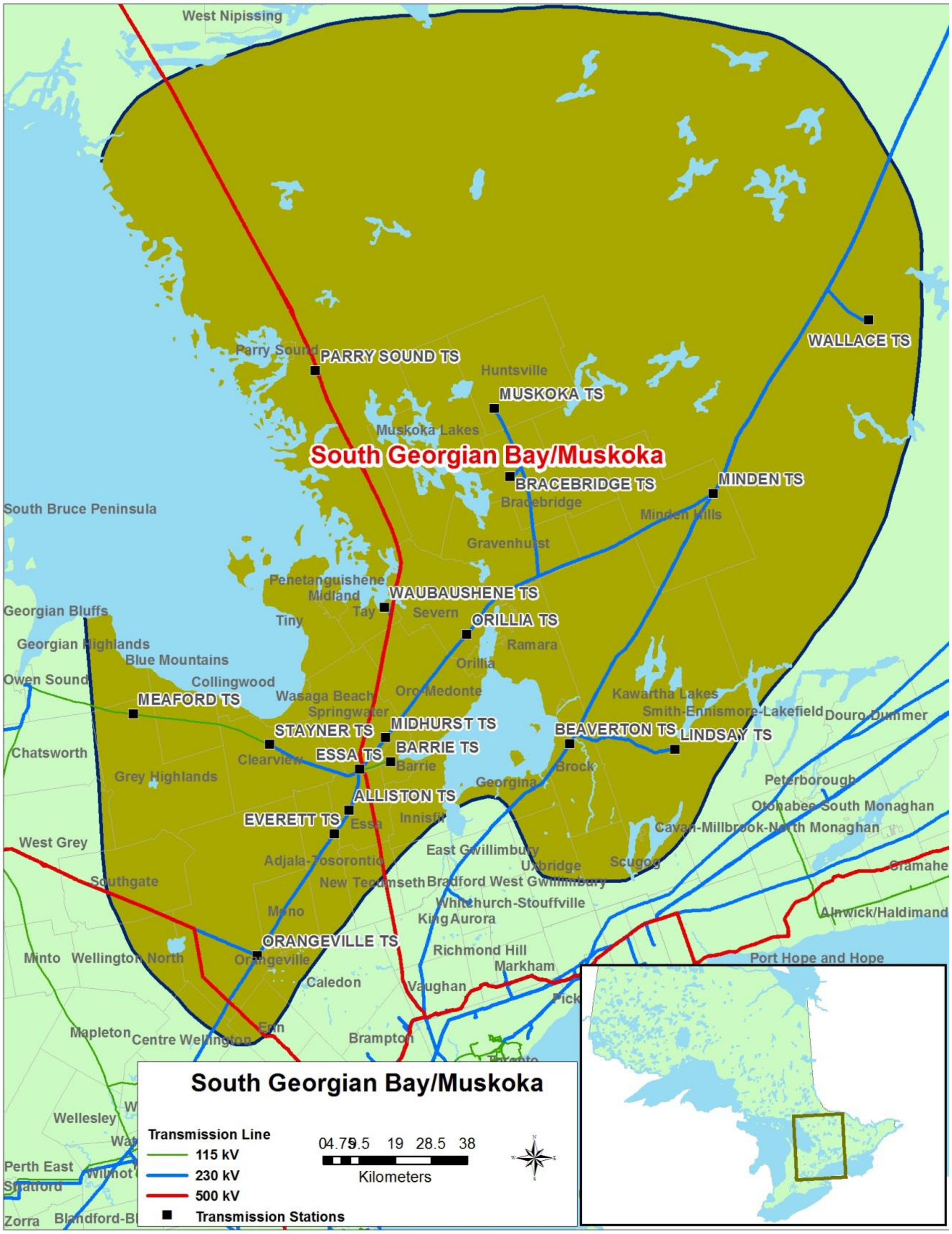


Figure 4 – Southern Georgian Bay/Muskoka Region

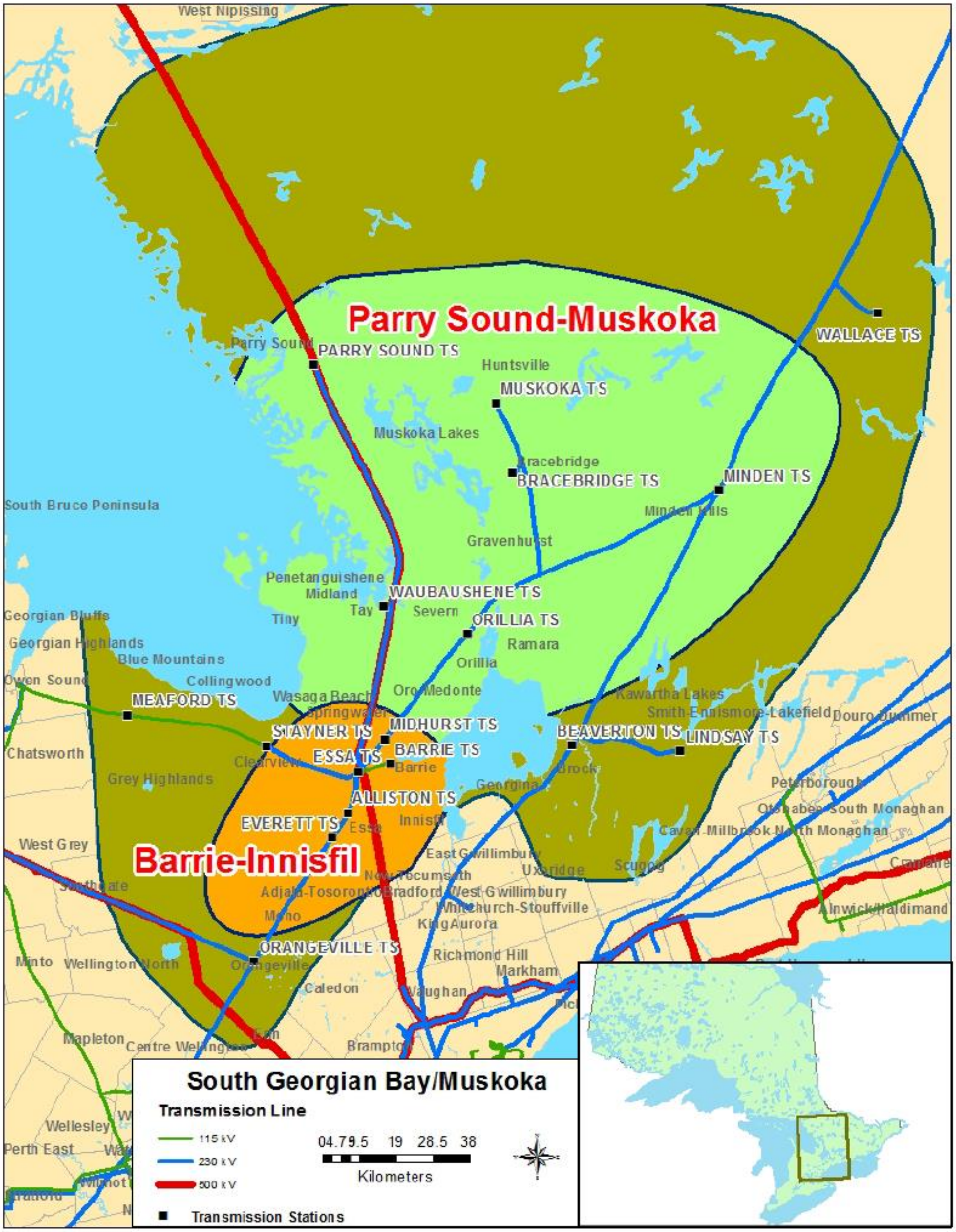


Figure 5 – Barrie-Innisfil/Muskoka Sub-Regions

Customer Consultations

EEDO 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.

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

For surveys performed in 2017 and 2019, EEDO retained RedHead Media Solutions Inc. to conduct their individual survey and received customer satisfaction index scores of 71.8% (2017) and 73.0% (2019) overall. The statistical surveys, with a 95% confidence level, canvassed a number of key areas including power quality and reliability, price, billing and payment, communications, and the overall customer service experience. The surveys are comprised of approximately 400 randomly selected interviews of EEDO customers among the low volume customer base (residential customers and general service under 50kW customers). For the 2014/2015 reporting period, EEDO engaged Utility Pulse to conduct their individual utility specific customer satisfaction survey with a 95% confidence level and received a rating of "A" on its customer satisfaction survey.

This information was used to determine level of ratepayer support for EEDO'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 2019 – 2023 planning period.

EEDO plant locations approval on roadways consultation

As part of the regular project planning process, EEDO consults with the Town or County to obtain approval for new pole locations on roadway related to a specific project. The Town or County are the "owner" of the roadway and their approval for any works constructed on it is required. EEDO initiates the process and provides the Town or County with detailed project plans for new/replacement poleline infrastructure located on road allowance. Work is able to commence when Town or County approval is obtained for the proposed project pole locations. This is a regular administrative consultation process and does have a material impact on the DSP investment plan.

Road works consultation

Major road work (i.e. widening) by the Town or the County may require relocation of EEDO infrastructure. The consultations are initiated by the Town or the County and are designed to ensure proper and timely coordination of effort to complete the road project. This may involve Town or County coordination with other entities such as telecommunication utilities, etc. This is a project specific consultation process and any material impacts have been incorporated into the DSP investment plan.

EEDO REG plans

EEDO initiated consultation with the IESO on the REG investment plan included in the DSP. The IESO reviews the REG investment plan and provides a comment letter on the appropriateness of the plan with respect to:

- the applications it has received from renewable generators for connection in EEDO's service area;
- whether EEDO has consulted with the IESO, or participated in planning meetings with the IESO;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments; and
- whether the REG investments proposed in the DSP are consistent with any Regional Infrastructure Plan.

The IESO comment letter is provided in 5.2.2d.

Other Consultations

EEDO 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, etc. The

CHEC Group is an association of 16 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.

Town of Collingwood Emergency Plan

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

5.2.2b Final deliverables of the consultation process

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 would require regional coordinated planning. Two Working Groups were established to undertake Integrated Regional Resource Plans (IRRP) for each sub-region to address the needs in these areas. EEDO 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 EEDO. EEDO took no further part in the IRRP process.

The IRRPs were completed and issued in December 2016. The Hydro One RIP was issued in August 2017. The IRRPs and RIP do not have any impact on the 2019 – 2023 DSP.

5.2.2c Material Documents used in the consultation process

As part of the consultation process, EEDO (CPC) provided its load forecast to the Regional Planning working group. The load forecast is shown in Tables 6 and 7 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 6 – EEDO 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 7 – EEDO Winter Peak Load Forecast

5.2.2d REG Investments - IESO comment letter

EEDO has not proposed any REG investments during the 5-year Distribution System Plan (DSP) period, and as such, no letter from the IESO is required.

5.2.3 Performance Measurement for continuous improvement

5.2.3a Metrics used to monitor distribution system planning performance

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

<u>Customer oriented performance - Customer survey</u>

On a periodic basis, EEDO undertakes customer satisfaction surveys 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 EEDO performance and where they think EEDO could improve service. EEDO's target is maintain an Overall Customer Satisfaction Index score of 70% or higher.

<u>Customer oriented performance - Service Reliability</u>

Service reliability issues (i.e. Trouble Calls), as noted in crew Field & Time Reports, are reviewed by the Manager of Hydro Operations on a daily basis. Control Room logs are also received that cover any after-hours calls received by Alectra Inc. Control Room staff who provide after-hours call answering service for EEDO. 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). For this DSP it is assumed that OEB baselines will be derived from 2014-2018 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

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

The 2019 – 2023 reliability targets for SAIDI and SAIFI are based on the historical 2014 – 2018 5-year average for these measures.

These indices provide EEDO 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, EEDO 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 8 – 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. Negative trending may indicate that EEDO may be required to undertake specific actions to improve service reliability.

Customer oriented performance - Bill impacts

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.

EEDO 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, EEDO'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.

EEDO's target for this measure is for rate impacts in residential and general service classes to remain within OEB rate mitigation guidelines.

Customer oriented performance - Billing accuracy

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 EEDO 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.

EEDO's target for this measure is to maintain a minimum of 98% accuracy per OEB guidelines.

Cost Efficiency and Effectiveness - DSP Spending Progress Report

EEDO will be monitoring its execution of the projects and programs included in the DSP. On an annual basis, EEDO 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.

EEDO's target for this measure is that DSP actual spending to be within 10% of approved DSP capital budget.

Asset/System Operations Performance – Reg. 22/04

As with every other Ontario distributor, EEDO'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

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

Asset/System Operations Performance –Substation loading

EEDO's municipal substations have been identified as being single most critical asset category within its distribution system. EEDO looks to maintain substation normal loading at approximately 75% of the ONAN (Oil Natural Air Natural) MVA capacity of the substation transformer. EEDO 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 regular basis. The substation loading indicates the effectiveness of EEDO's asset utilization planning.

EEDO's target for this measure is that substation peak demand is not to exceed transformer maximum nameplate rating.

Asset/System Operations Performance –Feeder loading

As part of EEDO 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 500 Amps maximum load. Feeder loading is collected and reviewed on a monthly basis. The feeder loading indicates the effectiveness of EEDO's asset utilization planning and contingency capability.

EEDO's target for this measure is that feeder loading is not to exceed the 500A capacity level.

Asset/System Operations Performance – System Losses

EEDO 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.

A summary of performance targets to be referred to throughout the period of the DSP are shown in Table 9 below:

Performance Indicator	Targets				
	2019	2020	2021	2022	2023
Reliability (SAIFI)	0.68	0.68	0.68	0.68	0.68
Reliability (SAIDI)	1.24	1.24	1.24	1.24	1.24
Overall Customer Satisfaction Index score	70%+	-	70%+	-	70%+
Billing Accuracy	98%	98%	98%	98%	98%
Billing Impact	Annual rates subject to OEB approval (within mitigation guidelines)				
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 <= 500 Amps	Feeder peak load <= 500 Amps	Feeder peak load <= 500 Amps	Feeder peak load <= 500 Amps	Feeder peak load <= 500 Amps
Losses	<5%	<5%	<5%	<5%	<5%

Table 9 – 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.

5.2.3b Unit Cost Metrics

Unit cost metrics for the 2014 – 2018 period are presented below as per prescribed format of Appendix 5-A.

Metric Category	Metric	Measures	
		2018	2014-2018 Average
Cost	Total Cost per Customer[1]	$296	$310
	Total Cost per km of Line[2]	$14,174	$14,882
	Total Cost per MW[3]	$92,617	$94,079
CAPEX	Total CAPEX per Customer	$163	$173
	Total CAPEX per km of Line	$7,793	$8,325
O&M	Total O&M per Customer	$133	$137
	Total O&M per km of Line	$6,381	$6,557

Notes to the Table:

1 The Total Cost per Customer is the sum of a distributor's capital and O&M costs divided by the total number of customers that the distributor serves.

2 The Total Cost per km of Line is the sum of a distributor's capital and O&M costs divided by the total number of kilometers of line that the distributor operates to serve its customers.

3 The Total Cost per MW is the sum of the distributor's capital and O&M costs divided by the total peak MW that the distributor serves.

Explanatory Notes on Adverse Deviations
Metric Name: Cost
2018 Cost metrics less than average
Metric Name: CAPEX
2018 CAPEX metric less than average
Metric Name: O&M
2018 O&M metric less than average

Table 10 – 2014 – 2018 Unit Cost Metrics

5.2.3c Summary of historical performance and performance trends

Customer oriented performance - Customer survey

Within range of the historical period, EEDO has had three customer surveys. One was performed by UtilityPulse in 2014 and the other two were performed by Redhead Media Solutions Inc. in conjunction with the CHEC group. The 2014 customer survey results are shown in the table below:

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

Table 11 – 2014 Customer Survey Results

The 2014 survey results provide customer perception's of EEDO key performance categories of Company Image and Management Operations. The survey result for Customer Care was 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 this survey, EEDO scored at or higher than National and Ontario benchmarks in all three performance categories.

The 2017 and 2019 customer survey results are shown in the table below:

	2017	2019
Familiarity with CPC (2017)/EEDO(2019)	68%	44%
Services provided satisfaction	77%	75%
Reliability satisfaction - outages	88%	84%
Outage restoration satisfaction	76%	67%
Power Quality satisfaction	88%	82%
Bill accuracy satisfaction	75%	71%
Bill pay/receive option satisfaction	83%	87%
Customer Service satisfaction	53%	39%
Communications satisfaction	62%	61%
Familiarity with % of bill to EEDO	28%	27%
EEDO % of bill is reasonable	40%	49%
Bill Cost is major impact	63%	47%
Customers well served by Ontario electricity system	54%	69%
Overall Customer Satisfaction Index score	71.8%	73.0%

Table 12 – 2017 and 2019 CHEC Group Customer Survey Results

The 2019 survey indicates that overall customer satisfaction has increased and cost has become less of an issue as compared to the 2017 survey. EEDO Senior Management will continue to review customer feedback to determine if any actions need to be taken to maintain targeted performance in Overall Customer Satisfaction prior to the next survey.

Customer oriented performance - Service Reliability

The EEDO interruption history for all interruptions and interruptions excluding loss of supply are shown in Figure 6 and Table 13 (2014 – 2018) below:

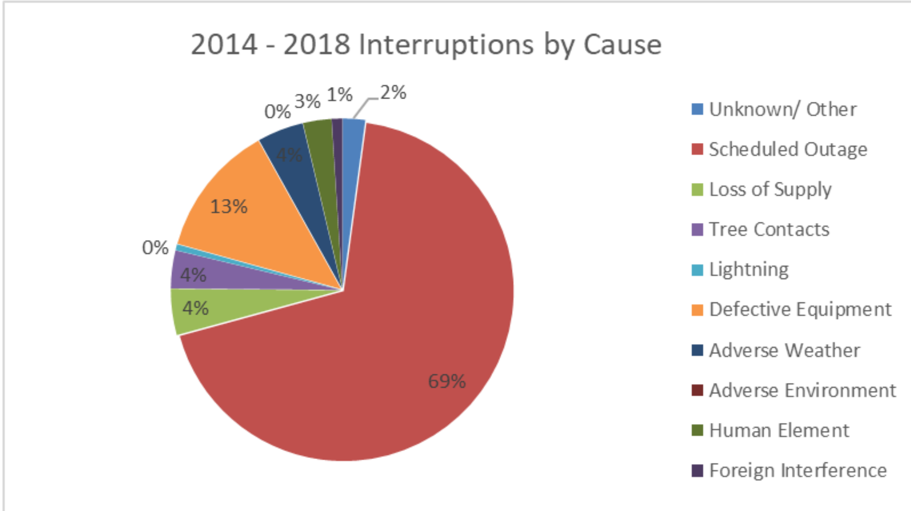


Figure 6 – 2014 - 2018 Outages by Type

Year	All interruptions	All interruptions excluding loss of supply	All interruptions excluding loss of supply & MEDs
2014	15,741	10,424	N/A
2015	19,616	14,541	N/A
2016	34,626	27,908	14,095
2017	36,463	14,220	14,220
2018	18,254	3,429	3,429

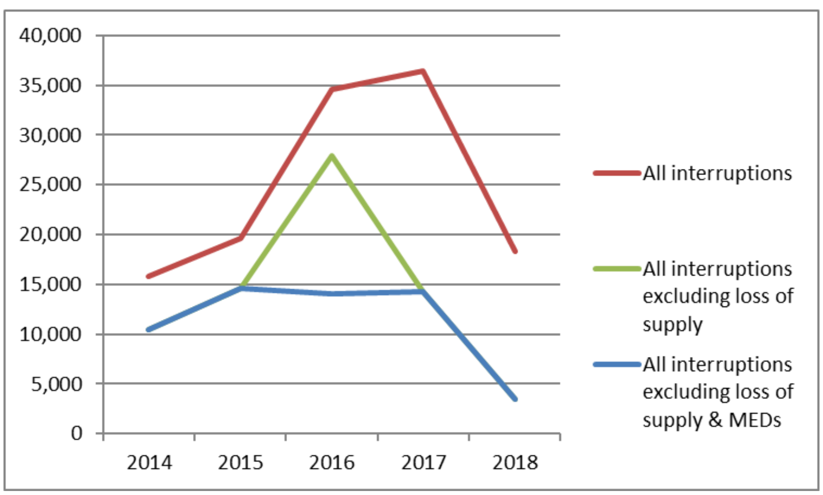


Table 13 – 2014 – 2018 Interruption history

Service reliability statistics are compiled monthly.

The 2014 - 2018 interruption history table shows the significant impact of Loss of Supply and MEDs on overall reliability.

EEDO's SAIFI, SAIDI and CAIDI statistics for the 2014 – 2018 historical period are shown below:

Year	SAIFI	SAIDI	SAIFI - no LOS	SAIDI - no LOS	SAIFI - no LOS, MED	SAIDI - no LOS, MED
2014	0.95	0.03	0.63	0.3	0.63	0.3
2015	1.19	2.77	0.88	2.36	0.88	2.36
2016	2.06	5.96	1.66	5.41	0.84	1.54
2017	2.14	4.52	0.84	1.51	0.84	1.51
2018	1.08	1.93	0.2	0.5	0.2	0.5
Avg	1.48	3.04	0.84	2.02	0.68	1.24

Table 14 – 2014 – 2018 Reliability Statistics

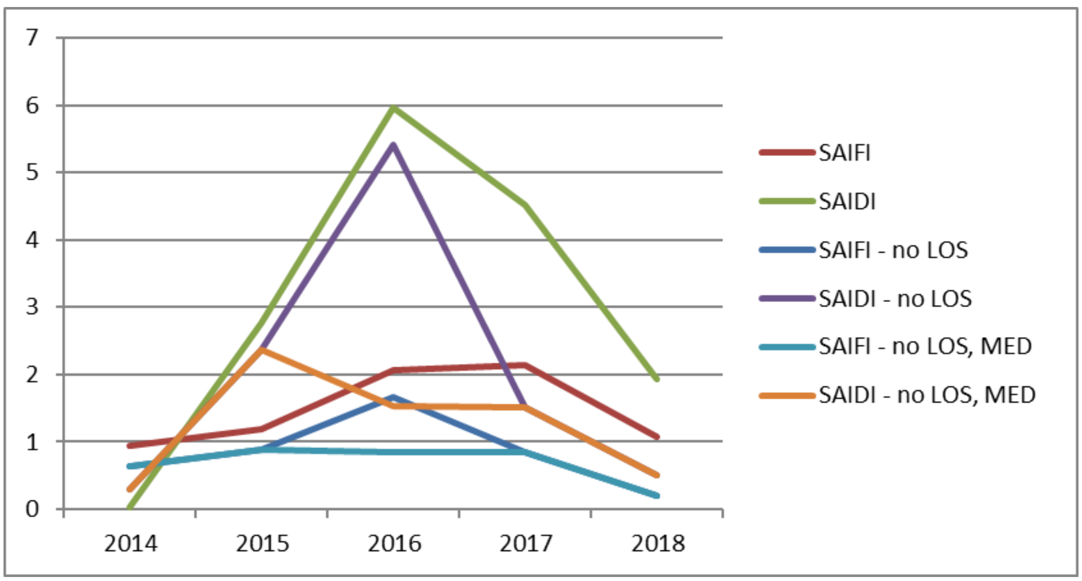


Table 15 – 2014 - 2018 Reliability statistics – Bulk loss of supply excluded

SAIFI (no LOS, no MEDs) has been averaging approximately 0.68 over the historical period. This equates to an EEDO customer experiencing an outage once every 17 months.

SAIDI (no LOS, no MEDs) has been averaging approximately 1.24 over the historical period. This equates to an EEDO average of 74 minutes of outages per customer.

Historical outage causes are listed below:

Code	Primary Cause	2014	2015	2016	2017	2018	Average
0	Unknown/ Other	6	8	0	4	1	4
1	Scheduled Outage	98	176	181	100	55	122
2	Loss of Supply	3	5	9	14	8	8
3	Tree Contacts	8	1	13	6	4	6
4	Lightning	1	0	0	3	1	1
5	Defective Equipment	29	25	34	11	13	22
6	Adverse Weather	9	5	20	1	4	8
7	Adverse Environment	0	0	0	0	0	0
8	Human Element	9	5	6	2	2	5
9	Foreign Interference	3	2	3	0	1	2

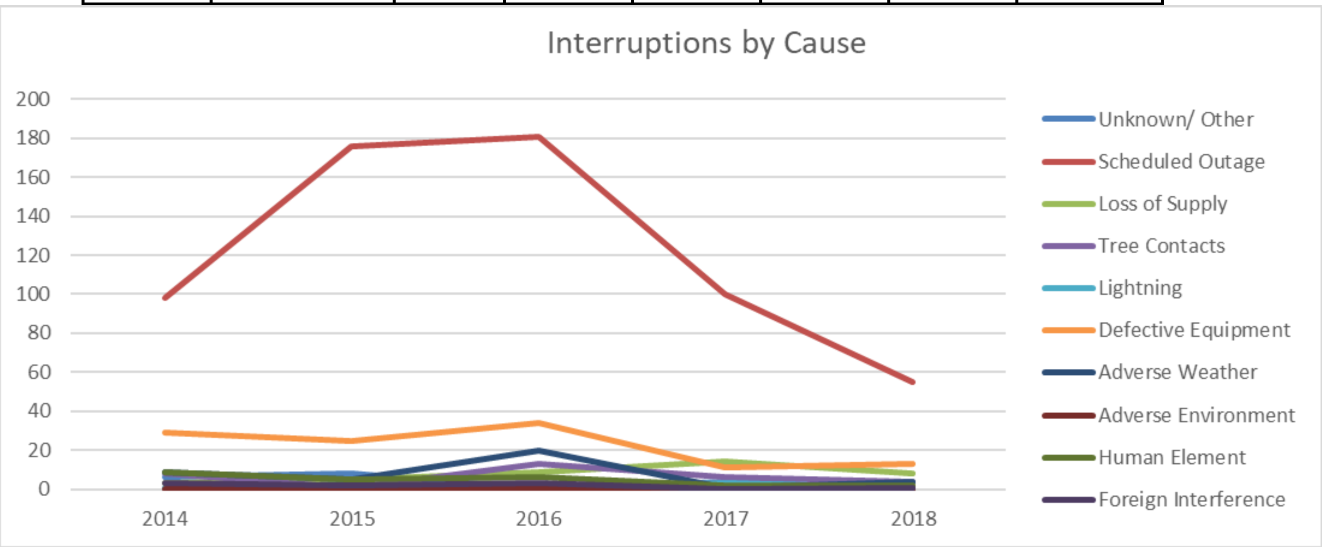


Table 16 – 2014 – 2018 Outage causes

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 mitigate severe weather impacts on the distribution system (i.e. hardening, enhanced vegetation management).

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, EEDO residential and GS customers have had an average annual distribution rate (fixed and variable charges) increase of 1.46% (2014 – 2018) based on the 5-Year Price Cap index methodology. Under this adjustment process, rates are mechanistically set at inflation (determined by OEB) less productivity (determined by OEB) and stretch factors (determined by OEB).

	Rate Filing	**Residential**	**GS<50**	**GS>50**	**Annual Average**
2014	Price Cap Index	1.4%	1.4%	1.4%	1.4%
2015	Price Cap Index	1.3%	1.3%	1.3%	1.3%
2016	Price Cap Index	1.8%	1.8%	1.8%	1.8%
2017	Price Cap Index	1.75%	1.75%	1.75%	1.75%
2018	Price Cap Index	1.05%	1.05%	1.05%	1.05%

Table 17 – 2014 – 2018 Bill Impacts

Customer oriented performance - Billing accuracy

EEDO’s calculated billing accuracy for 2014 - 2018, as part of its annual RRR filing, has averaged 99.96%.

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

EEDO 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
2014	0	1
2015	0	0
2016	0	1
2017	0	2
2018	0	1

Table 18– 2014 – 2018 ESA Audit Results

Audits are performed in the following year. For example, the 2014 audit was done in the period May 1 – 30, 2015. Needs Improvement issues have been minor in nature and have been addressed. EEDO 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 EEDO service area is winter peaking. All MS peaks shown in the chart below are non-coincident.

MS Name	Capacity (MVA)	2018 Peak Load (MVA)	Avg % Utilization
Collingwood MS1	6/6.7	5.3	79
Collingwood MS2	8	5.54	69
Collingwood MS3	3/3.4	2.2	65
Collingwood MS4	5/5.6	4.3	77
Collingwood MS5	10	3.72	37
Collingwood MS6	6/6.7	5.2	78
Collingwood MS7	5	1.8	36
Collingwood MS8	4	1.2	30
Collingwood MS9	10.67	2.4	22
Collingwood MS10	6	1.9	32
Stayner MS1	5	2.5	50
Stayner MS2	5	2.77	55
Thornbury MS1	6	2.1	35
Thornbury MS2	5	2	40
Total	84.67	42.93	50

Table 19– EEDO 2018 Substation loading

Average station utilization is at 50%. The EEDO 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

EEDO system losses over the historical period are shown below:

2014	2015	2016	2017	2018
3.7%	4.93%	5.95%	5.81%	2.57%

Table 20 – EEDO System Losses

Losses have trended in the 3.7 – 6.0% range over this historical period.

RRFE Performance Scorecard

The RRFE performance scorecard metrics indicate that EEDO 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. EEDO is currently ranked in Group 2 with respect to Efficiency Assessment (stretch factor = 0.15%).

5.2.3d 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

EEDO conducts customer satisfaction surveys on a periodic basis. Surveys show that the customers are generally satisfied with EEDO's overall performance. EEDO has met its Overall Customer Satisfaction Index target of 70% or higher.

EEDO 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 2019 survey reaffirmed customer perceptions that EEDO delivers high reliability services (84% satisfaction).

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

EEDO 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 EEDO 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 EEDO. It will result in improved outage documentation and information accuracy.

Outage cause codes and anecdotal information indicate that system renewal 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 EEDO's DSP development. The smoothed 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).

Customer oriented performance - Billing accuracy

The relatively high performance by EEDO 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 - 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. Going forward, annual DSP spending exceeding a designated threshold of +/- 10% will require a detailed variance explanation.

Asset/System Operations Performance – Reg. 22/04

EEDO continues to demonstrate prudent compliance with O. Reg. 22/04 and as such ESA compliance continues to play a key role in project prioritization. No specific projects have been identified that need to be factored into the DSP. In general, ensuring Reg22/04 compliance is maintained has been taken into consideration in the development of the DSP and EEDO's asset management and capital expenditure planning process.

Asset/System Operations Performance – Substation loading

The substation loading pattern in the EEDO'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.

Asset/System Operations Performance – Feeder loading

Existing performance is within planning capacity thresholds and as such there is no specific impact on the DSP.

Asset/System Operations Performance – System Losses

2018 and future performance is expected to be within performance targets and as such there is no specific impact on the DSP other than open point designation on certain feeders.

RRFE Performance Scorecard

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.

9/24/2018

Performance Outcomes	Performance Categories	Measures		2013	2014	2015	2016	2017	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		100.00%	100.00%	100.00%	100.00%	100.00%	flat	90.00%	
		Scheduled Appointments Met On Time		100.00%	100.00%	100.00%	100.00%	100.00%	flat	90.00%	
		Telephone Calls Answered On Time		98.00%	70.90%	73.70%	68.90%	81.92%	down	65.00%	
	Customer Satisfaction	First Contact Resolution			99%	99.68	99.06	99.17			
		Billing Accuracy			99.94%	99.98%	99.96%	99.97%	up	98.00%	
		Customer Satisfaction Survey Results			A	A	71.8	71.8			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness				84.00%	84.00%	83.30%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C	flat		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0	flat		0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000	flat		0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		0.10	0.03	2.36	1.54	1.51	up		0.46
		Average Number of Times that Power to a Customer is Interrupted [2]		0.73	0.63	0.88	0.84	0.84	up		0.62
	Asset Management	Distribution System Plan Implementation Progress			In progress	In progress	90.75	82.04			
	Cost Control	Efficiency Assessment		3	3	2	2	2			
		Total Cost per Customer [3]		$500	$512	$528	$541	$512			
		Total Cost per Km of Line [3]		$23,849	$24,260	$24,739	$26,084	$25,314			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Energy Savings [4]				9.71%	25.02%	68.98%			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%	100.00%	100.00%	flat	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.25	1.10	1.40	1.29	1.34			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.41	1.27	1.41	1.26	1.31			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	8.98%	8.98%	8.98%	8.98%	8.98%			
			Achieved	8.40%	11.21%	10.86%	10.03%	11.65%			

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

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

Table 21 – RRFE Performance Scorecard

5.2.4 Realized efficiencies due to smart meters

EEDO has deployed smart meters to all its residential customers. EEDDO has completed MIST meter deployment to all its GS>50kW customers well in advance of the OEB target of 2020. A total of 124 MIST meters have been installed.

Smart meters communicate back to EEDO through Advanced Metering Infrastructure (AMI) provided by Sensus. This has eliminated the need to read meters manually. All residential smart meters have “last gasp” technology (“last gasp” technology allows the meter to communicate to utility operations when power has been lost) incorporated into them.

The smart meters also send out a variety of alarms (i.e. tampering, part power, hot socket, etc.) that allow EEDO to respond to the issue with the customers service in a timely manner. Most of time EEDO responds before the customer is aware of issue. Some examples of this are underground burn offs and under voltage supply. Smart meters notifications have also been instrumental in allowing EEDO to catch illegal electrical work being performed.

Smart meter consumption data is used with EEDO’s “SmartMap” software to build an analytic model of the distribution system. Data from smart meters, wholesale meter points and other sensors create a sophisticated simulation of the current distribution system. SmartMAP helps EEDO Operations staff understand, plan and operate the system more effectively.

Smart meter consumption data will be especially useful with the continuing deployment of electric vehicles and associated home charging stations. The impact of these systems on the local distribution transformer can be determined and facilitate any decisions as to the necessity of upgrading the transformer to a higher capacity unit.

Load profile data allows EEDO to bill TOU, allowing customers to take advantage of off-peak rates. Reduced on-peak consumption assists in deferring capacity expansion needs.

Smart meter load profile data has proven to be beneficial in resolving a number of customer issues including high bill complaints, flickering lights and low/high voltage complaints. EEDO Customer Service representatives can review consumption history in detail with the customer and this has led to successful resolution of most billing inquiries. Consumption reviews with the customer also educates them with respect to the benefits of energy conservation.

5.3 Asset Management Process

This section of the Distribution System Plan provides a high-level overview of EEDO's asset management process.

EEDO'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. EEDO is continuing efforts to improve the information available to the asset management process for all major equipment.

5.3.1 Asset Management Process overview

5.3.1a Asset Management objectives and relationship to corporate goals

EEDO's asset management objectives align with EEDO's corporate goals and are implicitly summarized in EEDO'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 7 – EEDO 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 everyday actions, to EEDO 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 8 – EEDO Values

EEDO's Mission, Vision and Corporate Values form the foundation for EEDO'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

EEDO has identified six (6) Asset Management Objectives that align with corresponding Corporate Objectives:

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

The Corporate and Asset Management objectives form the high-level philosophy framework for EEDO's investment program and are implicitly embedded in EEDO'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	1. ESA Non-Compliance 2. ESA SEII	1. “Zero” NC 2. SEII = 0
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	1. Customer Survey 2. DSP feedback	1. Customer survey results => previous survey for: a) Customer Care b) Company Image c) Mgmt Operations 2. Feedback from web posting and PICs => 70% agreement with plan
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	2024 GIS capabilities > 2018 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.	1. Reportable spills to the MOE 2. New REG connected on time	1. Zero reportable spills to MOE from Code 5 events 2. 90%+

Table 22 – 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 six 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 EEDO. 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 0.3

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 EEDO'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 EEDO 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

Objective	Weight
Safety	0.30
Reliability	0.20
Customer Service	0.20
Financial Integrity	0.15
Effective Integration	0.10
Environmental	0.05
Total	1.00

Table 23 – 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. EEDO has in place inspection and routine maintenance programs to achieve this.

EEDO 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 EEDO's planning framework.

5.3.1b Asset Management process components

EEDO's Asset Management planning cycle is shown in Fig. 9 below.

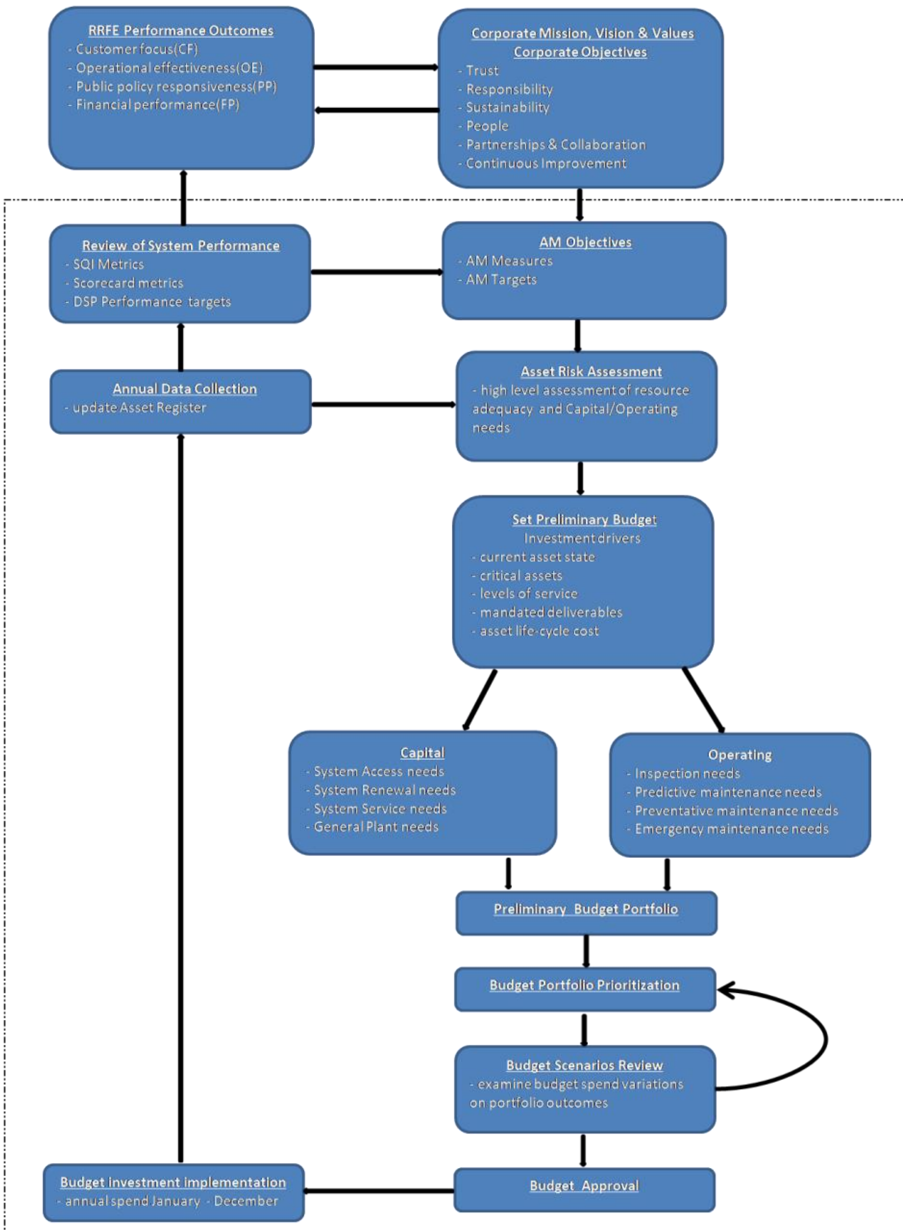


Figure 9 – EEDO Asset Management Planning Cycle

The Asset Management planning cycle is a process designed to achieve EEDO's Asset Management Objectives. The process is a cyclical one that begins with a review of system performance and whether current performance meets EEDO's asset management objectives. Asset performance information and annual asset data collection is used to update EEDO'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 EEDO'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 EEDO, 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 Oracle financial management system, the Harris Northstar Customer Information System (CIS) and Operations Records databases/files.

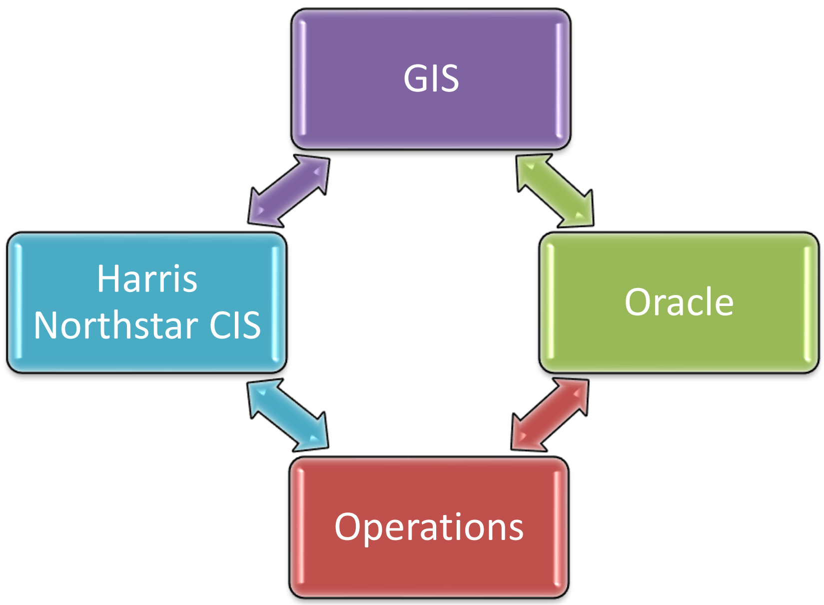


Figure 10 – EEDO Asset Register structure

The Harris Northstar CIS platform is hosted by the CHEC group (UCS), while the Oracle platform is owned and maintained by EPCOR Utilities Inc.

The GIS is the primary asset register component that holds attribute information (age, etc.) for all non-general plant assets. The GIS also holds asset inspection and maintenance information.

The EEDO 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 Oracle financial management system.

The EEDO 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 Control room staff.
- Application addition of the Utilismart "SmartMAP" software provides a geographic analysis tool for the distribution system. SmartMAP 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. SmartMAP helps EEDO 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
Oracle Financial Management System	Accounting/Regulatory	- IFRS and Regulatory asset value - asset useful life studies - contributed capital	-digital database
	Accounting/Regulatory	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 CHEC 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 24 - EEDO 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

EEDO'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. EEDO's desired level of service and mandated deliverables

4. EEDO's asset life-cycle cost considerations

5. EEDO'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 proposed budget envelope as a guide and information from the Asset Register, investment planning then proceeds. A preliminary 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. 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.

At this stage of the process, non-mandatory capital investments are scored to provide an initial prioritization ranking based on risk and benefit considerations. Mandatory capital projects are automatically included as per scheduled need. In general, mandatory 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)

Mandatory investments are allocated budget envelope funds first. Remaining budget envelope funds are allocated to non-mandatory investments in the System Renewal, System Service and General Plant categories.

The portfolio is compared to the budget envelope and prioritized investments are paced/scheduled to optimize system performance, costs and risks relevant to service delivery. EEDO uses a Risk and Value scoring mechanism developed internally to classify and prioritize investments. See 5.4.2 for further details on project prioritization.

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 capital envelope 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 a revised capital budget envelope may be considered, and the capital investment portfolio would be re-evaluated to optimize system performance.

Final budget and project selection determined through EEDO senior management discussion and review. Once this has been done, the completed budget is presented to the EEDO Board of Directors for approval.

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

5.3.2a. Description of the distribution service area

General
As of December 31, 2018, EEDO serves approximately 15,512 residential customers, 1,768 GS<50 customers and 128 GS>50 customers in a combined service area of 45 square kilometers.

Locations

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

Temperature and Weather

The EEDO 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.

Service Area Density

The EEDO 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 EEDO that offers four-season recreation and leisure pursuits for both residents and visitors alike.

Underground and Overhead Assets

EEDO is responsible for maintaining distribution and infrastructure assets deployed, including 211 kilometers of overhead lines and 151 kilometers of underground lines.

Customer and Economic Growth

From 2014 to 2018 the average annual customer growth rate was 1.5% for EEDO. The residential sector was the primary driver for customer growth.

Customer Class	Avg. Annual Growth
Residential	1.6%
GS<50	0.8%
GS >50	1.0%

Table 25 – Average annual customer growth by class 2014-2018

The economic development strategy in the EEDO area (primarily the Town of Collingwood) focuses on six main strategic themes:

1. Existing Business Support
2. Small Business Growth
3. Workforce at Work
4. Great Place for Business
5. Business & Tourism promotion
6. Business Service Priority

The strategy is expected to strengthen the Town's existing businesses and grow start-ups and small companies.

<u>IESO/HONI Relationship and Neighbouring Utilities</u>

EEDO is embedded off Hydro One's Stayner TS and Meaford TS. EEDO is a registered Market Participant dealing directly with the IESO and has eight metering points metered by Hydro One. Consequently, EEDO 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, EEDO is billed monthly by Hydro One for Transmission and Low Voltage Charges.

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

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

- Hydro One
- Wasaga Distribution Inc.

Map of the EEDO service area is shown below.

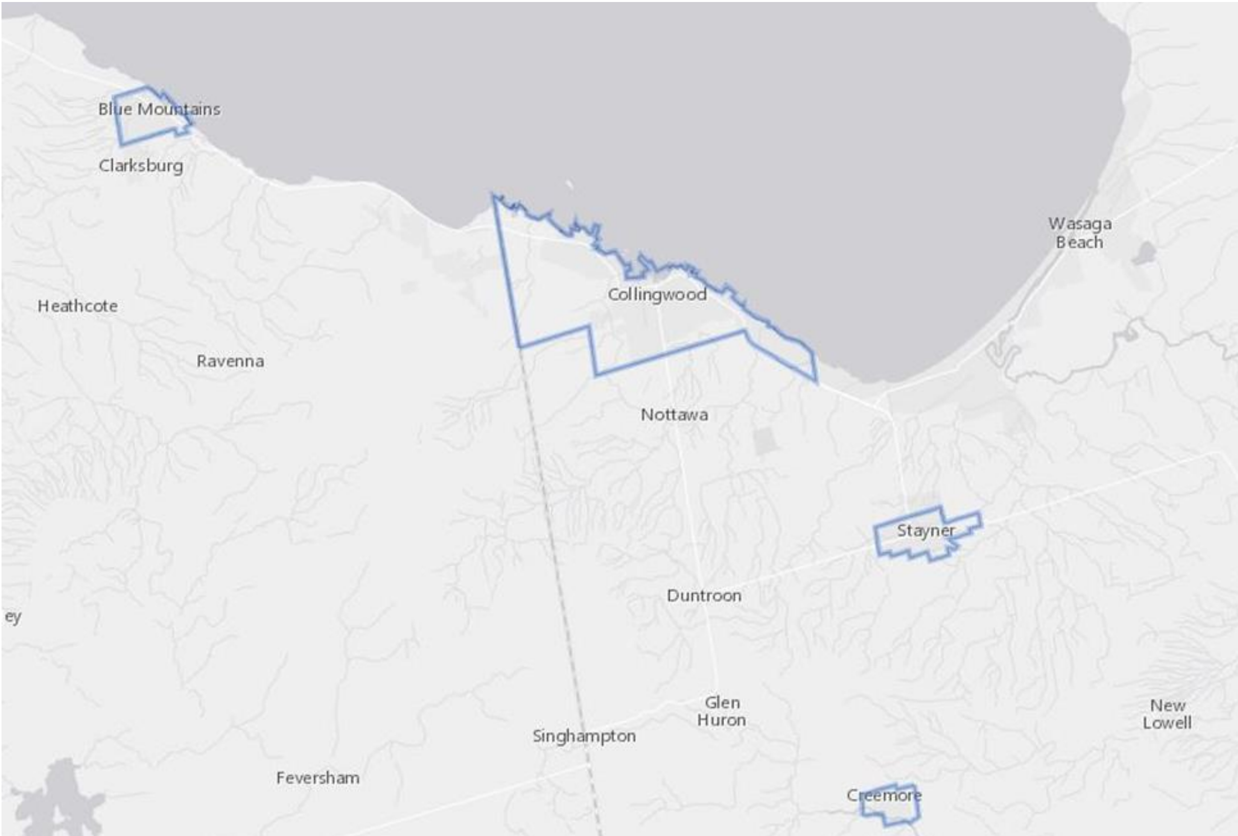


Figure 11 – EEDO Service Territory

5.3.2b System configuration

The EEDO 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 EEDO 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 two 8.32kV express feeders (F2 & F4) from Hydro One owned Creemore DS. 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. EEDO owns and operates the portions of the 44kV feeders inside EEDO 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 26 below:

IESO ID# Main Meter Altemate Meter	Meter Seal Expiry	Name	Circuit ID	Voltage	Metering Installation Type	Built
1000006500	2025	Thornbury PME	Meaford M2	44KV	Primary	2004
1000006501	2024					
1000010440	2020	Creemore DS F2 PME	H1 Creemore DS F2	8.32 KV	Primary	2018
1000010441	2024					
1000036670	2021	Creemore DS F4 PME	H1 Creemore DS F4	8.32KV	Primary	2018
1000036671	2025					
1000008670	2019	Collingwood South PME	Stayner TS M3	44KV	Primary	1992
1000008670	2024					
1000006080	2025	Collingwood West PME	Stayner TS M7	44KV	Primary	2004
1000006081	2024					
1000006100	2019	Collingwood East PME	Stayner TS M8	44KV	Primary	1997
1000006101	2024					
1000006090	2019	Wasaga Beach PME 3	H1 Brocks Beach DS F1	8.32KV	Primary	1996
1000006091	2025					
1000016630	2019	Stayner MS 1	Stayner M5	4.16KV	Secondary	1976/2006
1000016631	2027					
1000009890	2025	Stayner MS 2	Stayner M2	4.16KV	Secondary	1988
1000009891	2023					

Table 26 – 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 EEDO's distribution substations. One user is an IESO registered market participant. There are 14 municipal substations in EEDO 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 27 – EEDO MS summary

Municipal station locations are shown in Figures 12, 13, 14 and 15 below:

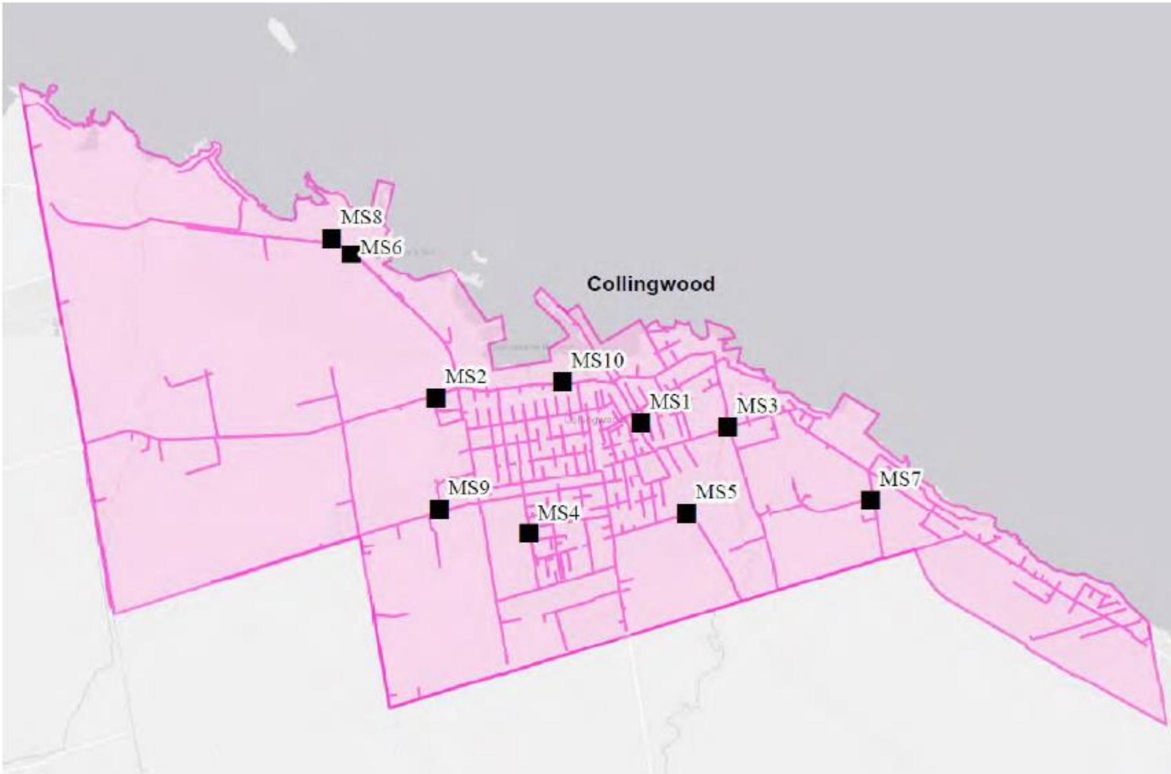


Figure 12 – Collingwood MS locations

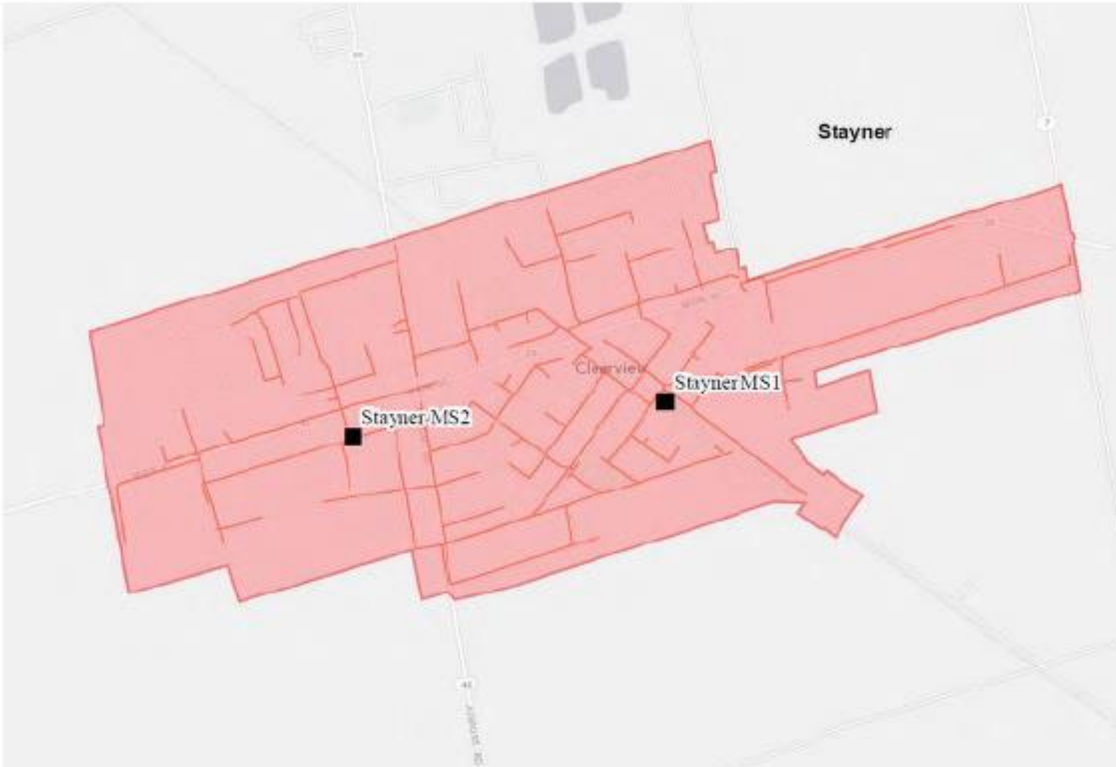


Figure 13 – Stayner MS locations

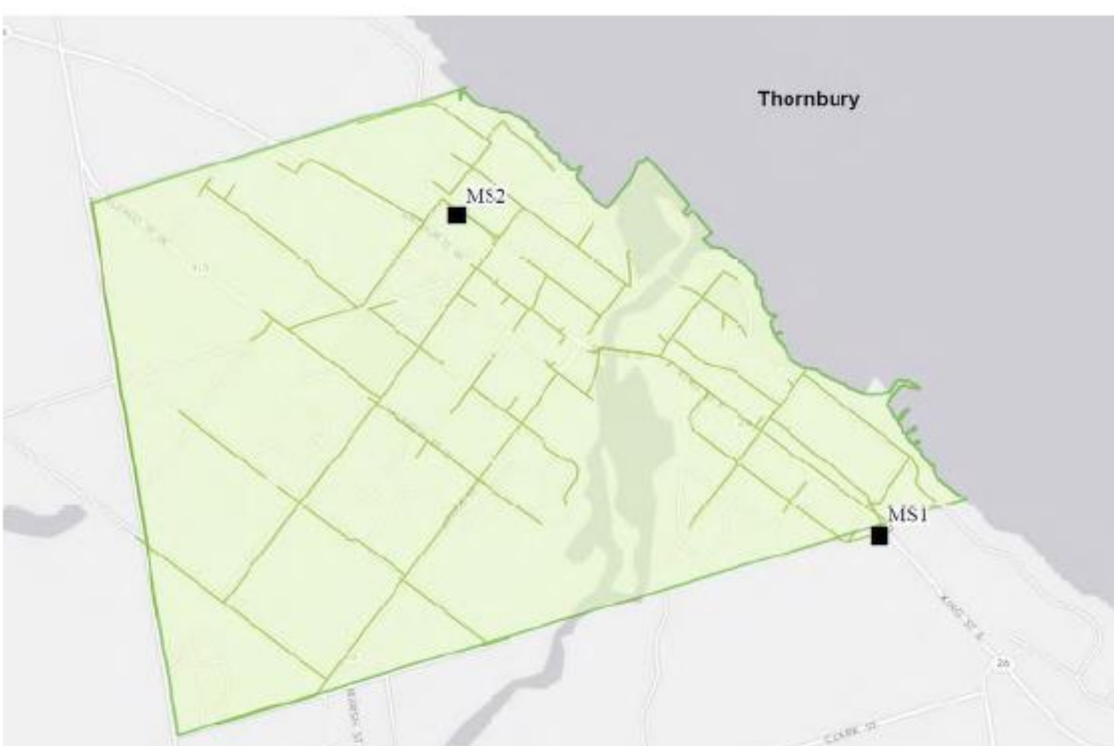


Figure 14 – Thornbury MS locations

Figure 15 – 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 2018, there are approximately 211km of overhead and 151km of underground 4.16kV & 8,32kV circuitry. There also are a total of 34km of 44kV circuitry owned by EEDO. 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:

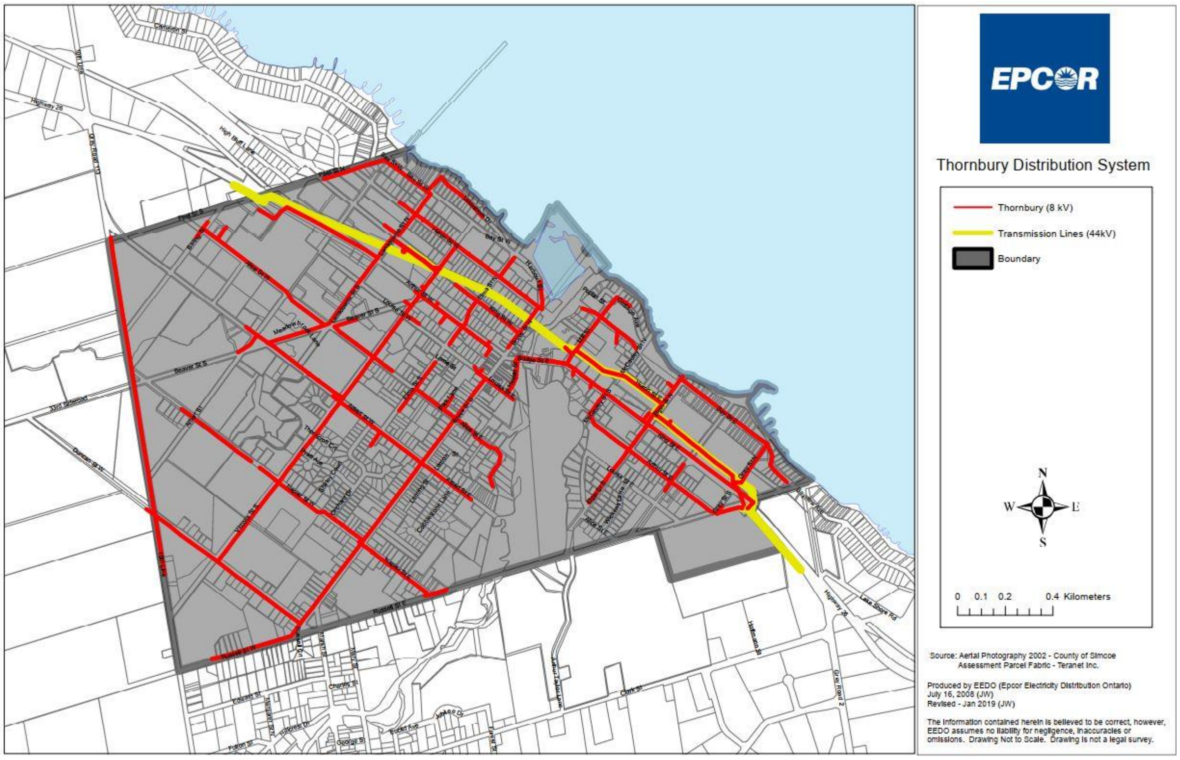


Figure 16 – Thornbury Distribution - Feeder System

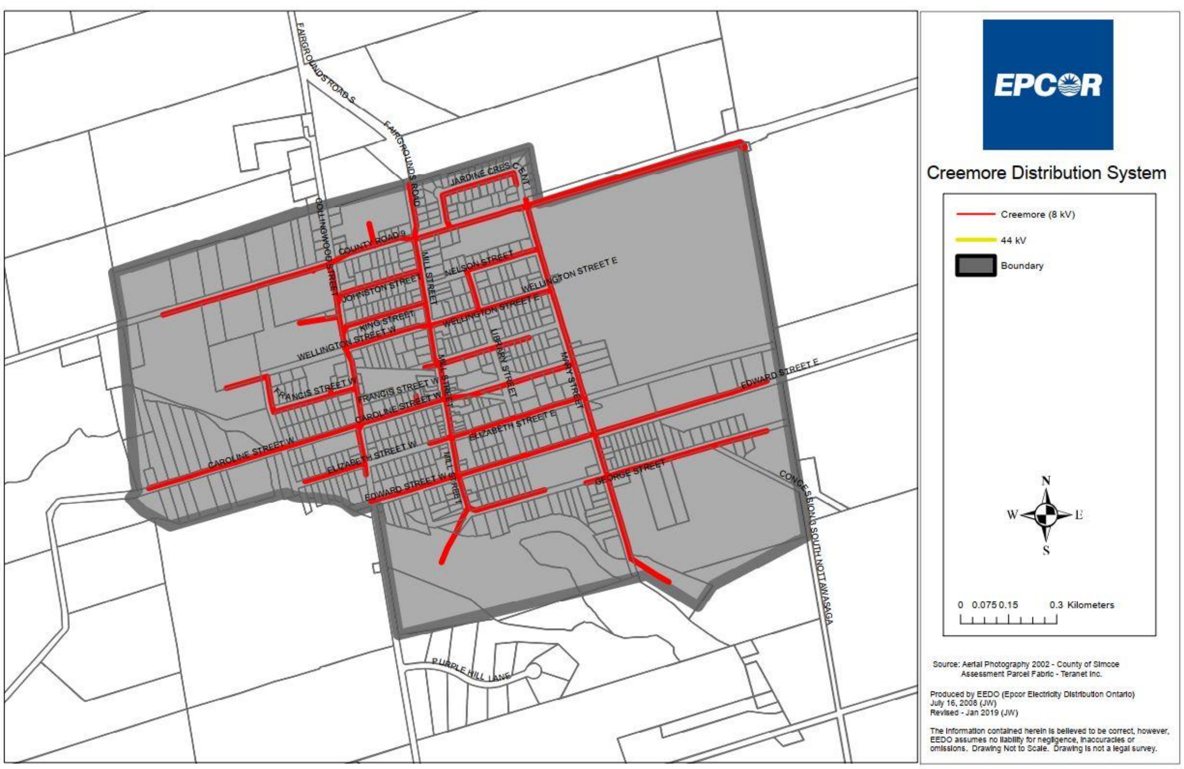


Figure 17 – Creemore Distribution - Feeder System

Figure 18 – Stayner Distribution - Feeder System

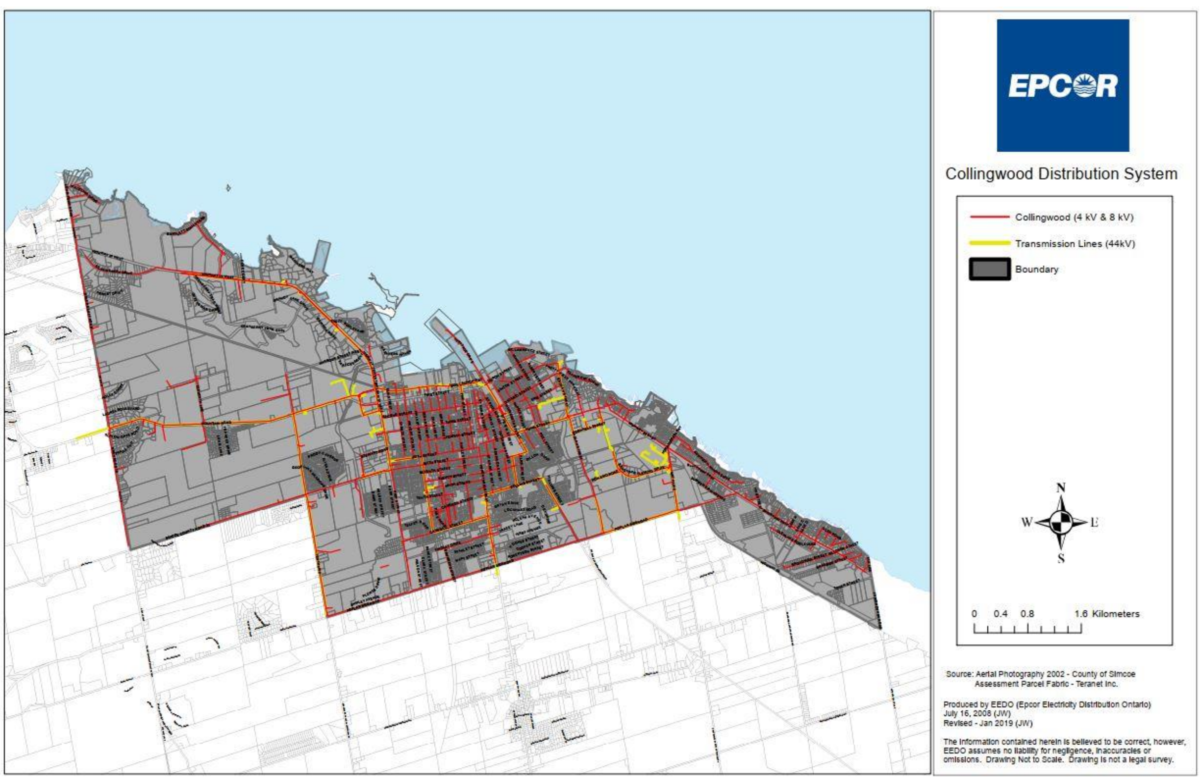


Figure 19 – Collingwood Distribution - Feeder System

5.3.2c Information by asset type

Information regarding EEDO'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	5	4	0	5	0	30
Circuit Breakers		38	45	17	4	0	9	2	28
PME		18	40	1	4	7	0	4	19.8
Meters[3]		17609	15	0	8796	4150	4193	470	5.5
Pole Mounted Transformers[3]		1009	40	0	0	1009	0	0	N/A
Pad Mounted Transformers[3]		1212	40	0	0	1212	0	0	N/A
Pad Mounted Switchgear[3]		42	30	0	0	42	0	0	N/A
Junction Boxes[3]		35		0	0	35	0	0	N/A
Overhead switches (44kV)[3]		154	45	0	0	154	0	0	N/A
Overhead switches (4/8kV cutouts)[3]		825	45	0	0	825	0	0	N/A
Poles[3]	Wood Poles	5064	45	554	673	1192	571	2074	N/A
Overhead Conductor[2,4]		211	N/A	0	0	0	100	111	N/A
Underground Cable	5kV XLPE cable	1 km	25	1	0	0	0	0	N/A
	15kV Jacketed TRXLPE[4]	153 km	30	0	0	0	92	61	N/A

Note 1 - Typical Useful Life derived from Kinectrics "Asset Depreciation Study for the Ontario Energy Board", July 8, 2010

Note 2 - October 2018 data

Note 3 - Assets assumed in mid-life condition based on inspection/patrol exception reporting

Note 4 - Assets assumed in early – life condition based on inspection/patrol exception reporting

The data is as of October 2018 except as noted.

Table 28 - 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 EEDO 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, 5kV UG primary cable and wood poles.

EEDO 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 (<10% life remaining). Programs are in place to replace this cable (~1km remaining), at specified locations, with 15kV rated cable of 1/0 size.

Over 1225 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 2019 – 2023 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.

5.3.2d Assessment of existing system capacity

EEDO is a winter peaking utility. Winters in EEDO'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. 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.

The chart below indicates an average utilization rate of 50% for MS capacity based on 2018 peak demand numbers. All MS peaks shown in the chart below are non-coincident.

MS Name	Capacity (MVA)	2018 Peak Load (MVA)	Avg % Utilization
Collingwood MS1	6/6.7	5.3	79
Collingwood MS2	8	5.54	69
Collingwood MS3	3/3.4	2.2	65
Collingwood MS4	5/5.6	4.3	77
Collingwood MS5	10	3.72	37
Collingwood MS6	6/6.7	5.2	78
Collingwood MS7	5	1.8	36
Collingwood MS8	4	1.2	30
Collingwood MS9	10.67	2.4	22
Collingwood MS10	6	1.9	32
Stayner MS1	5	2.5	50
Stayner MS2	5	2.77	55
Thornbury MS1	6	2.1	35
Thornbury MS2	5	2	40
Total	84.67	42.93	50

Table 29 – EEDO 2018 MS Utilization

EEDO has a spare MS transformer (Primary 44kV; Secondary 4.16kV 3 MVA) that can be used for emergency replacement of any of the EEDO 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

EEDO 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. EEDO 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 EEDO distribution stations. EEDO is winter peaking. The feeder loading stats are non-coincident and are shown in the following chart:

Feeder	Planning Capacity (Amps)	Feeder Capacity (Amps)	2018 Peak Load (Amps)	% Planning Utilization
Collingwood MS1	625			
F1	125	500	122.0	97.6%
F2	125	500	56.9	45.5%
F3	125	500	159.1	127.3%
F4	125	500	165.4	132.3%
F5	125	500	196.1	156.9%
Collingwood MS2	833			
F1	167	500	132.9	79.6%
F2	167	500	138.9	83.2%
F3	167	500	196.4	117.6%
F4	167	500	143.8	86.1%
F5	167	500	134.6	80.6%
Collingwood MS3	312			
F1	104	360	60.1	57.8%
F2	104	360	65.0	62.5%
F3	104	360	166.7	160.3%
Collingwood MS4	520			
F1	130	360	111.9	86.1%
F2	130	500	159.0	122.3%
F3	130	360	62.8	48.3%
F4	130	400	229.7	176.7%
Collingwood MS5	1040			
F1	260	400	63.5	24.4%
F2	260	200	6.4	2.5%
F3	260	500	352.3	135.5%
F4	260	400	78.4	30.2%
F5	0	400	0	0
F6	0	400	0	0
Collingwood MS6	625			
F1	125	500	216.2	173.0%
F2	125	500	138.3	110.6%
F3	125	500	42.7	34.2%
F4	125	500	113.5	90.8%
F5	125	500	174.9	139.9%
Collingwood MS7	520			
F1	130	400	0	0

F2	130	400	115.2	88.6%
F3	130	400	112.1	86.3%
F4	130	400	0.0	0.0%
F5	185	400	19.7	10.6%
Collingwood MS8	416			
F1	104	400	27.5	26.5%
F2	104	400	57.7	55.5%
F3	104	400	10.1	9.7%
F4	104	400	76.4	73.5%
Collingwood MS9	1110			
F1	0	500	0	0
F2	278	500	236.1	84.9%
F3	278	500	46.9	16.9%
F4	278	500	0	0
F5	278	500	29.9	10.7%
Collingwood MS10	625			
F1	313	500	9.8	3.1%
F2	313	500	249.3	79.7%
F3	0	500	0	0
Stayner MS1	520			
F1	130	400	93.3	71.7%
F2	130	400	96.0	73.8%
F3	130	400	199.4	153.4%
Stayner MS2	520			
F1	130	400	138.4	106.4%
F2	130	400	190.8	146.8%
F3	130	400	19.3	14.9%
Thornbury MS1	312			
F1	104	400	75.0	72.1%
F2	104	400	11.6	11.2%
F5	104	400	50.6	48.6%
Thornbury MS2	278			
F1	87	400	41.1	47.2%
F2	87	400	34.7	39.9%
F3	87	400	65.5	75.3%
Creemore DS (HONI)				
F2	140	400	59.0	42.1%
F4	140	400	89.0	63.6%

Table 30 – EEDO 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 EEDO's asset lifecycle optimization policies and practices.

5.3.3a Formal policies and practices

EEDO's policies and practices towards asset lifecycle optimization are derived from EEDO's Asset Management Policy and Asset Management Objectives. In managing its distribution system assets, EEDO'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 - EEDO'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 EEDO 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 Refurbishment /Replacement - EEDO 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, EEDO 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.

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.

Asset Inspection and Maintenance – EEDO 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. EEDO 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. EEDO'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 inspection, testing and servicing of elements of the distribution system. These activities include infrared thermography testing, transformer oil analysis, planned visual inspections, pole testing, 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 31 – Oil tests for MS power transformers

EEDO 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 Inspect. & 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 Swgr	Visual inspection	Every 3 years
	8.32/4.168kV Padmount Tx	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, 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 32 – 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).

Maintenance activities are reviewed monthly by EEDO Senior Management and quarterly by the EEDO Board of Directors to ensure programs are on track.

Asset replacement determination - Asset replacement is considered annually as part of EEDO's investment planning process along with the other capital projects scheduled for completion in the upcoming year. Mandatory asset replacements, due to near term significant safety or reliability issues are automatically included in the budget spend envelope. Non-Mandatory asset replacements are prioritized and scheduled as described in section 5.3.1. Non-Mandatory 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.

Maintenance Planning Criteria

Maintenance Planning criteria are developed in consideration of the Asset Management Objectives. Maintenance planning issues are identified through various methods and sources, primarily through feedback from distribution system operations, inspections and manufacturer's maintenance recommendations. 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.

5.3.3b Lifecycle Risk management

EEDO 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 EEDO'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 2019 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	1200+	5+ years	$10 M+
Live-front transformers	5	1 year (2019)	$295,000

Table 33 – Key Renewal Programs

The pole replacement program together with the line overhead line replacement projects are expected to replace over 850 of the 1200 poles+ currently in poor or very poor condition during the 2019 – 2023 DSP period. Long term replacement for material fleet and general plant assets will be accompanied by specific business cases as required.

Other assets in "very poor" and "poor" condition will be dealt with on a reactive basis.

Long term replacement plans have also been prepared for fleet and other general plant assets.

5.3.4 System Capability assessment for renewable energy generation

5.3.4a Applications from renewable generators > 10kW

EEDO has connected six renewable energy generators to date, as shown in Table 34 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 34 – List of REG connections

In addition to the > 10kW generation connections noted in Table 42, there are approximately 72 <10kW projects totaling just under 600kW connected to the EEDO distribution system.

5.3.4b Renewable generation connections anticipated 2019 -2023

In June of 2016, the IESO issued its list of contract offers for the FIT 4.0 program. There was one FIT 4.0 program contract in the EEDO service area. EEDO staff do not anticipate this project moving forward as the building that would house it is likely to be demolished.

In September 2017, the IESO issued its list of contract offers for the FIT 5.0 program. There are no FIT 5.0 program contracts in the EEDO service area.

The FIT programs have been subsequently cancelled by the IESO.

It is expected that all other renewable energy generator connections will be at the <10kW level during this period.

5.3.4c Capacity to connect REGs

The EEDO distribution system (MS stations) have capacity to connect REGs as noted in Appendix C. EEDO'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 REG connections in EEDO'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 35 – HONI TS station capacity for DGs

5.3.4d REG connection constraints

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

The EEDO 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 EEDO's connection capacity except for the Stayner M8 feeder which is currently limited to a little over 270kW 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, EEDO is subject to the Hydro One rule of 7% of Max Peak Load for F Class Feeders for determining Distributed Generation available capacity.

5.3.4e Embedded distributor connection constraint impacts

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

5.4 Capital Expenditure Plan

EEDO's Distribution System Plan details the programme of system investment decisions developed on the basis of information derived from EEDO'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 EEDO's asset management and capital expenditure planning process.

EEDO's Distribution System Plan includes information on prospective investments over a five year forward looking period (2019 – 2023) as well as planned and actual information on investments over the historical five year period (2014 – 2018).

5.4a Customer engagement activities to ascertain plan alignment

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

In October 2017, EEDO held a Small Business information session on the draft DSP in conjunction with the Collingwood Chamber of Commerce to solicit feedback from the commercial sector. 33 individuals attended the event with 20 providing feedback. The comments received at the session indicated a strong support for the objectives and content of the draft DSP but also indicated interest on plan impact on future electricity rates. Impact on electricity rates will be determined through the appropriate rate application process. See summary of session feedback in Appendix D.

In January 2018, EEDO held three (3) PICs on the draft DSP to solicit feedback from the general public. Ads advertising the PICs were run in local newspapers and were also posted on the EEDO website. Twitter was also used to put PIC notice out. The information centers were held in the communities of Collingwood, Thornbury and Stayner respectively. No members from the public attended the PICs in Stayner and Thornbury. One member from the public attended the PIC in Collingwood. No comments were provided by the individual and as such there were no changes to the DSP as a result of this consultation process. Consultation information is shown in Appendix E.

Another method EEDO uses is the customer satisfaction survey. The satisfaction survey is done on a periodic basis to compare evolving customer satisfaction over time. EEDO 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, 2017 and 2019 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 EEDO could undertake, from the customer's perspective, are shown in Table 36 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 36 – 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 37 – 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.

In 2018, EEDO participated in the CHEC group survey by Redhead Media for Electricity Safety. In this survey, EEDO achieved a Public Safety Awareness (PSA) index score of 83.3%.

EEDO also posted the draft 2018-2022 DSP to its website, from June 14 to December 1 2017, along with a short survey form for customers to provide feedback about the DSP and their preferences. The DSP page on the EEDO website was visited 1,623 times, The DSP flipbook was visited 354 times, the .pdf of the DSP was downloaded 277 times and the DSP survey link was accessed 635 times.

Figure 20 – DSP Public Engagement Statistics

Only 10 surveys were completed from out of the 635 accessing parties. The responses received supported the DSP investment plan as prudent and providing value to the customer and as such there were no changes to the draft DSP as a result of this survey process. See Appendix F for summary of the survey responses. EEDO has updated the Distribution System Plan to cover the 2019 -2023 forecast period.

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

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

2019	2020	2021	2022	2023
Customer Satisfaction Survey	Safety Survey	Customer Satisfaction Survey	Safety Survey	Customer Satisfaction 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
Customer meetings	Customer meetings	Customer meetings	Customer meetings	Customer meetings
DG meetings	DG meetings	DG meetings	DG meetings	DG meetings
Website/ Twitter – general info	Website/ Twitter – general info	Website/ Twitter – general info	Website/ Twitter – general info	Website/ Twitter – general info

Table 38 – EEDO 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.

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 39 below:

, Stakeholders	Stakeholder Needs	Stakeholder Interests	Stakeholder Perception of Planning Risks
EEDO 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
EEDO 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; accurate real-time information and market rule compliance by market participants	Comprehensive utility forecasting process; LDC adherence to technical and communication protocols	Inaccurate information contribution to Regional planning processes; 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 39 – Stakeholder Needs, Interests and Perceptions

5.4b System forecast development 2019-2023

It is expected that the operational and service requirements driving EEDO's capital expenditures, and found within its DSP, will generally remain consistent through the 2019 to 2023 planning window. EEDO expects moderate load and customer growth in line with development plans that directly impact EEDO'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 1200 poles have been determined to be in poor or very poor condition. Over 850 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.

5.4.1 Capital Expenditure Planning Process Overview

5.4.1a Analytical tools and methods used for Risk management

System Reliability

Smart Map provides real time information on outages and aids in the compilation of outage statistics that are used to aid in reliability risk management. EEDO manages reliability risk through outage analysis and the investment planning process. The EEDO investment planning guide is used to aid in the prioritization of investments through a scoring mechanism that quantifies value and risk deferral of investments with respect to EEDO's Corporate goals and Asset Management Objectives.

System Reliability - 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 EEDO 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 40 below:

Asset Class	Contingency Event	Contingency Plan
MS Power Transformers	Transformer failure requiring off-site servicing	1. Spare Transformer (from EEDO 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 40 – 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.

Cyber-Security

EEDO is committed to ensuring our systems are secure and to preserving the privacy of its customers. During the forecast period, a continued investment in hardware, software and training will enable EEDO to fully comply with the Ontario cyber security framework, as well as to further enhance its overall security posture.

Climate Change Adaptation

Climate change is expected to increase the risk and frequency of severe weather events that can impact system reliability.

EEDO's distribution system is expected to be primarily impacted by severe changing weather conditions related to:

1. Temperature

2. Heavy Rain/Flooding

3. High Wind velocity/Wind gusts

4. Tornadoes

5. Freezing Rain > 25mm

Climate change projections show primarily increased probabilities of occurrence (return times) in the categories listed above. Magnitude of events experienced may increase slightly.

There are two key concepts related to improving the performance of electrical distribution systems in severe weather situations: hardening and resiliency. Hardening deals with physical changes (i.e. undergrounding of lines) to make infrastructure less susceptible to severe weather-related damage. Resiliency deals with increasing the ability to recover quickly from damage to distribution infrastructure components or to any of the external systems on which they depend.

At this time EEDO does not have any capital investments targeted to specifically address climate change. However a number of line rebuild projects will result in higher strength poles compared to the original installation thereby implicitly "hardening" the line.

From an operating perspective, EEDO has enhanced its preventative maintenance practices in the area of vegetation management to mitigate the impacts of severe wind and storm events. The tree trimming program has been set at a 3-year cycle to minimize outage impacts due to severe weather related vegetation contact with overhead lines.

5.4.1b Processes, tools and methods used to identify, select, prioritize and pace projects in each investment category

Project Identification

The projects that EEDO selects for its capital budget are the ones that are required to ensure the safety, efficiency, and reliability of its distribution system to allow EEDO 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 mandatory in nature and are budgeted and scheduled to meet the timing needs of the external proponents.

System renewal projects are non-mandatory in nature and are identified through EEDO'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 non-mandatory in nature and are identified through EEDO'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 non-mandatory 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

Mandatory 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.

Non-mandatory 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, EEDO 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.

EEDO's multi-year System Renewal programs have been prepared and paced based on EEDO's desire to mitigate bill impacts for expenditures within EEDO's control. OEB rate mitigation guidelines are targets that EEDO strives to adhere to. EEDO'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. EEDO has developed multi-year programs that focus on proactively replacing key assets in the "Replace" 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 "Replace" 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 non-mandatory 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.

EEDO 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 EEDO's weighted corporate and asset management goals.

Objective	Weight
Safety	0.30
Reliability	0.20
Customer Service	0.20
Financial Integrity	0.15
Effective Integration	0.10
Environmental	0.05
Total	1.00

Table 41 – Objective weighting summary

Safety – This objective has been given the highest priority by EEDO. 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 0.3

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 EEDO'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 EEDO 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

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

5.4.1c 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 EEDO 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. EEDO 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. EEDO assumes that future revenue and avoided costs will be zero.

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

5.4.1d EEDO policy and procedure on incorporating non-distribution system alternatives

EEDO does not have any specific policy or procedure related to utilizing non-distribution system alternatives for system capacity or operational constraint relief. EEDO's activities in this area are delivered through the facilitation of distributed generation connection.

The amount of distributed generation impact, during the period of the Distribution System Plan does not offer any significant capacity or operational constraint relief to EEDO's distribution system.

EEDO actively participates in the Regional Planning process to identify any system capacity or operational constraint relief that can be achieved through cooperative planning and program execution with regional distributors and transmitters.

EEDO 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.

5.4.1e System Planning – opportunistic modernization of the distribution system

Updated SCADA system

In 2019, EEDO will be replacing their legacy SCADA system with a new system. The C3-ilex SCADA system has reached end of life status. EEDO can no longer obtain software security updates or replacement hardware. Replacing the SCADA system will mitigate control/telemetry reliability risk for EEDO.

Adoption of innovative processes, services, business models, and technologies

EEDO continues to develop SCADA and SmartMAP systems to provide more timely, detailed and accurate information to Operations staff.

5.4.1f Distribution rate funded CDM programs

5.4.1.1 Rate-funded Activities to Defer Distribution Infrastructure

Proposed distribution rate funded programs may consist of:

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

5.4.1.1a CDM programs to target peak demand (kW) reduction

There are no rate-funded programs to target peak demand reduction.

5.4.1.1b Demand Response programs to defer distributions infrastructure

There are no rate-funded demand response programs to defer distribution infrastructure.

5.4.1.1c Programs to improve the efficiency of the distribution system

System losses and asset utilization are within guidelines. There are no specific rate-funded programs to improve the efficiency of the distribution system. Opportunistic improvements to distribution system efficiency, in conjunction with other investment needs, are considered on a case by case basis.

5.4.1.1d Energy Storage programs to defer capital spending

There are no rate-funded energy storage programs to defer capital spending.

5.4.2 Capital Expenditure Summary

The Capital Expenditure Summary provides a 'snapshot' of EEDO's capital expenditures over a 10-year period, including five historical years and five forecast years.

For 'summary' purposes the entire costs of individual projects or activities are allocated to one of four investment categories on the basis of the primary (i.e. initial or 'trigger') driver of the investment. The investment categories are:

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

For material projects, costs are allocated to the relevant investment categories.

Brief explanatory notes are provided to explain the factor(s) and/or circumstances underlying marked changes in the share of total investment represented by a given investment category over the forecast period relative to 'actual' spending over the historical period.

Explanatory notes for year over year 'Plan vs. Actual' variances for individual investment categories are provided where:

• for any given year "Total" 'Plan' vs. 'Actual' variances over the historical period are markedly positive or negative; or

• a trend for variances in a given investment category is markedly positive or negative over the historical period.

This is the first DSP filed by EEDO. Plan/Budget information by category is not available for the 2014 and 2015 years. EEDO's last Cost of Service filing was for 2013 rates (EB-2012-0116).

All actual and forecast expenditures are for distribution activities.

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated
Distribution System Plan Filing Requirements

First year of Forecast Period: *2019*

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2014			2015			2016			2017			2018			2019	2020	2021	2022	2023
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access		421	--		561	--	319	259	-18.8%	303	421	38.9%	581	414	-28.7%	312	517	354	361	391
System Renewal		482	--		623	--	1,558	1,116	-28.4%	2,116	2,118	0.1%	1,895	1,306	-31.1%	2,118	2,450	2,374	2,881	2,865
System Service		512	--		395	--	1,015	697	-31.3%	51	36	-29.4%	51	3	-94.1%	300	75	77	79	81
General Plant		387	--		131	--	621	508	-18.2%	626	459	-26.7%	652	139	-78.7%	569	658	586	264	568
TOTAL EXPENDITURE	2,521	1,802	-28.5%	3,389	1,710	-49.5%	3,513	2,580	-26.6%	3,096	3,034	-2.0%	3,179	1,862	-41.4%	3,299	3,700	3,391	3,585	3,905
System O&M		$ 2,169	--		$ 2,389	--	$ 2,298	$ 2,482	8.0%	$ 2,517	$ 2,190	-13.0%	$ 2,651	$ 2,310	-12.9%	$ 2,645	$ 2,711	$ 2,856	$ 2,848	$ 2,905

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed. However, use the last Board-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their planned budget in each subsequent historical year up to and including the Bridge Year.

2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year): 12

Explanatory Notes on Variances (complete only if applicable)

Notes on shifts in forecast vs. historical budgets by category

System Renewal spending increase in forecast period reflects increase in resources directed to address plant in very poor and poor condition. System Service spending high in 2019 in order to repalce legacy SCADA system.

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

Overall spending reduced in 2016 and 2018 due to labour resource issues.

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

Table 42 – Capital Expenditure Summary

5.4.3 Justifying Capital Expenditures

5.4.3.1 Overall Plan

5.4.3.1a Comparative expenditures by category 2014 – 2018

The comparative expenditures by category over the historical period are shown 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

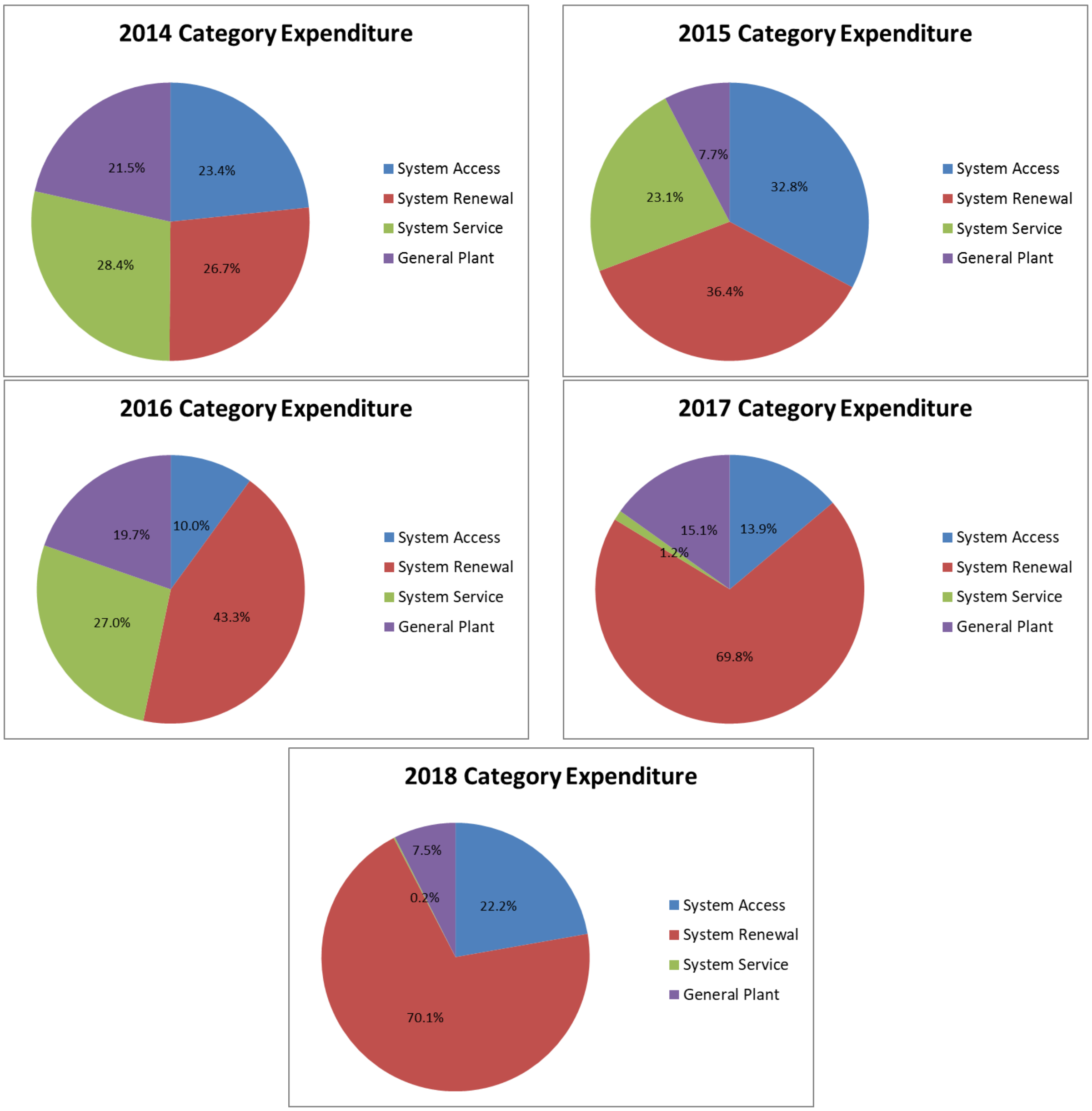


Figure 21 – 2014 – 2018 Capital Expenditure Charts

Historical spending and variance explanation by category is given below

System Access

EEDO's System Access investments are driven by others. EEDO is obligated to connect new load and new renewable generation. EEDO 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.

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

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The level of system access expenditures in each of 2014 to 2018 historical years has varied between $2592k and $561k.

- 2014 actuals (CGAAP) were $420,523, net of capital contributions of $351,231. The majority of net budget expense was for Smart Meter expenditures.
- 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 EEDO poles).
- 2016 actuals (IFRS) were $258,591 net of capital contributions of $1,739,589. The decrease from 2015 of $302,364 was due to a decrease in smart meter expenditures and even though Customer Initiated work increased, a considerable amount of these expenses were offset by contributed capital.
- 2017 actuals (IFRS) were $421,266 net of capital contributions of $527,957. The increase from 2016 of $162,675 was primarily due to increased smart meter expenditures and reduced capital contributions due to a decrease in Customer Initiated work.
  2018 actuals (IFRS) were $414,338 net of capital contributions of $1,004,456. Reduced smart meter expenditures were offset by increased Customer Initiated work.

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

Projects	2014	2015	2016	2017	2018 Bridge Year	2019 Test Year
System Access						
Smart Meter Installation						
	$213,186	$263,273	$63,702	$231,674	$143,938	$142,184
Sub-Total	$213,186	$263,273	$63,702	$231,674	$143,938	$142,184
Customer Initiated and Road Authority Work						
	$184,831	$296,298	$194,889	$189,593	$270,400	$169,772
Sub-Total	$184,831	$296,298	$194,889	$189,593	$270,400	$169,772
Miscellaneous	$22,506	$1,384	$0	$0	$0	$0
Total	**420,523**	**560,955**	**258,591**	**421,267**	**414,338**	**311,956**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets						
Total	**420,523**	**560,955**	**258,591**	**421,267**	**414,338**	**311,956**

Table 43 – Historical spending - Key System Access Projects

The impact of mandatory Customer Initiated and Road Authority work on resources allocation to deal with non-mandatory work (i.e. System Renewal) is best shown by the yearly variation of Gross Costs and Contributed Capital in the table below:

Projects	2014	2015	2016	2017	2018 Bridge Year	2019 Test Year
Customer Initiated and Road Authority Work						
Gross	$536,062	$1,041,870	$1,934,478	$717,550	$1,274,857	$636,905
Contributed Capital	$351,231	$745,573	$1,739,589	$527,957	$1,004,456	$467,133
Sub-Total	$184,831	$296,297	$194,889	$189,593	$270,400	$169,772
Miscellaneous	$22,506	$1,384	$0	$0	$0	$0
Smart Meter Installation						
	$213,186	$263,273	$63,702	$231,674	$143,938	$142,184
Total Gross	$771,754	$1,306,527	$1,998,180	$949,224	$1,418,795	$779,089

Table 44 – Annual variations in mandatory Customer Initiated and Road Authority work

<u>System Renewal</u>

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

The level of system renewal expenditures in each of 2014 to 2018 historical years has varied between $0.5Mand $2.1M.

- 2014 actuals (CGAAP) were $481,925.
- 2015 actuals (IFRS) were $622,551. The increase from 2014 of $140,626 was primarily due to increased number of rebuild projects.
- 2016 actuals (IFRS) were $1,115,517. The increase from 2015 of $492,966 was primarily due to increased focus on pole and underground cable replacement programs.

- 2017 actuals (IFRS) were $2,118,108. The increase from 2016 of $1,002,591 was primarily due to reallocation of resources due to reduced Customer Initiated (System Access) work.
- 2018 actuals (IFRS) were $1,306,416. The decrease from 2017 of $811,692 was primarily due to the reallocation of resources to address increased Customer Initiated work (System Access).

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

Projects	2014	2015	2016	2017	2018 Bridge Year	2019 Test Year
System Renewal						
Pole Replacement Program						
	$222,714	$238,332	$335,339	$384,474	$370,665	$415,200
Sub-Total	$222,714	$238,332	$335,339	$384,474	$370,665	$415,200
MS1 to Highway 26 (Stayner Part 1)	$80,494	$0	$370	$0	$0	$0
Spruce St - 7th St to Griffin Rd	$51,031	$0	$0	$0	$0	$0
Tenth St – Spruce to Walnut	$0	$126,525	$0	$0	$0	$0
Hurontario Street South rebuild	$17,184	$65,472	$0	$0	$0	$0
2nd St - Simcoe St (back lanes)	$19,372	$55,046	$5,800	$4,387	$0	$0
Spare Parts - Transformers	$10,110	$67,668	$0	$175,504	$0	$0
Mary St & County Rd 9 Creemore	$0	$8,259	$77,186	$10,020	$58,051	$0
Campbell St - Telfer St. To Hurontario St	$0	$33,212	$199,965	$0	$0	$0
Oak Street (Sixth St to Campbell St)	$0	$14,891	$112,116	$217,909	$329	$0
Gibbard Cres North & South	$10,871	$7,416	$186,496	$94,170	$0	$0
Giffen Road	$397	$3,456	$67,546	$0	$0	$0
Osler Crescent	$0	$2,274	$70,746	$0	$0	$0
Highway 26 to Main St (Stayner) Part 2	$0	$0	$12,808	$315,817	$0	$0
Princeton Shores Blvd.	$0	$0	$2,898	$145,159	$0	$0
Brock Crescent Pole Trans Replacement	$23,804	$0	$72	$146,776	$0	$0
Leslie Drive Pole Trans Replacement	$0	$0	$0	$76,425	$65,289	$0
Lockhart Road Underground	$0	$0	$0	$67,188	$0	$0
Riverside Crescent, Thornbury Pole Trans Replacement	$0	$0	$0	$81,154	$0	$0
Heritage Drive 4.16kV Pole Line Rebuild	$0	$0	$0	$59,731	$0	$0
Patterson St - Collins to Lorne & out to Hume (44kV)	$0	$0	$0	$80,623	$0	$0
Stayner St MS2 to North Street	$0	$0	$0	$0	$125,923	$0
Katherine - Collins to Lorne & across Lorne to Minnesota (44kV)	$0	$0	$0	$226,504	$0	$0
MS2 - Collingwood U/G Feeder Egress	$0	$0	$0	$27,532	$111,506	$0
Raglan St - Hume to Ron Emo (44kV)	$0	$0	$0	$0	$150,693	$0
Birch St Pole Line Rebuild (1st St to 3rd St)	$0	$0	$0	$0	$219,238	$0
Napier North Rebuild	$0	$0	$0	$0	$0	$155,700
Napier South Rebuild	$0	$0	$0	$0	$0	$103,800
Heritage Drive 4.16kV Pole Line Rebuild	$0	$0	$0	$0	$0	$210,000
Market Street - Hume to Market Lane	$0	$0	$0	$0	$0	$93,420
Market Lane - St. Marie to St. Paul	$0	$0	$0	$0	$0	$62,280
Mason Road Underground Primary Cable Replacement	$0	$0	$0	$0	$0	$171,270
Alfred Street East & West Pole Line Rebuild (Bundled Conductor)	$0	$0	$0	$0	$0	$260,000
184 8th Street 5kV cables and Live Front Transformer Replacement	$0	$0	$0	$0	$0	$57,090
233 St. Paul Street Live Front Transformer Replacement	$0	$0	$0	$0	$0	$57,090
Connaught Public School 5kV Cable and Live Front Transformer Replacement	$0	$0	$0	$0	$0	$57,090
Elm Street Aprartment Live Front Transformer Replacement	$0	$0	$0	$0	$0	$57,090
10th Street Vista Blue Underground Rebuild Project	$0	$0	$0	$0	$0	$77,850
Elgin Street Pole Line Rebuild, Thornbury	$0	$0	$0	$0	$0	$120,000
Arthur Street East Pole Line Rebuild, Thornbury	$0	$0	$0	$0	$0	$220,000
Sub-Total	$213,263	$384,219	$736,001	$1,728,900	$731,029	$1,702,680
Miscellaneous	$45,948	$0	$44,176	$4,734	$204,721	$0
Total	**$481,925**	**$622,551**	**$1,115,517**	**$2,118,108**	**$1,306,416**	**$2,117,880**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets						
Total	**$481,925**	**$622,551**	**$1,115,517**	**$2,118,108**	**$1,306,416**	**$2,117,880**

Table 45 – Historical spending - Key System Renewal Projects

The majority of EEDO capital work is driven by System Access and System Renewal needs. Increased focus on System Renewal work beginning in 2016 has been balanced with System Access needs as shown in the table below:

CATEGORY	2014	2015	2016	2017	2018
	Actual	Actual	Actual	Actual	Actual[2]
System Access Gross	772	1,307	1,998	949	1,419
System Renewal	482	623	1,116	2,118	1,306
GROSS EXPENDITURE	1,254	1,930	3,114	3,067	2,725

Table 46– System Access and System Renewal Gross expenditures

<u>System Service</u>

System Service investments are non-mandatory 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 2014 to 2018 historical years has varied between $3k and $700k.

- 2014 actuals (CGAAP) were $511,718.
- 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 actuals (IFRS) were $697,012. The increase from 2015 of $301,658 was primarily due to work to accommodate new capacity from upgraded HONI station in the Creemore service area.
- 2017 actuals (IFRS) were $36,226. Spending has decreased from 2016 levels to lower historical values with the completion of the HONI station upgrade in the Creemore service area.
- 2018 actuals (IFRS) were $2,956. There was no significant System Service expenditure in 2018.

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

Projects	2014	2015	2016	2017	2018 Bridge Year	2019 Test Year
System Service						
SCADA						
	$13,696	$35,068	$2,000	$36,226	$0	$300,000
Sub-Total	$13,696	$35,068	$2,000	$36,226	$0	$300,000
10th Line - Poplar to Mountain Rd						
	$379,609	$0	$0	$0	$0	$0
Sub-Total	$379,609	$0	$0	$0	$0	$0
Mountain Rd - 10th to Cambridge						
	$12,001	$235,091	$122,743	$0	$0	$0
Sub-Total	$12,001	$235,091	$122,743	$0	$0	$0
Creemore upgrade						
	$0	$122,895	$572,269	$0	$0	$0
Sub-Total	$0	$122,895	$572,269	$0	$0	$0
Dist Stn Equipment <50kV						
	$106,412	$0	$0	$0	$0	$0
Sub-Total	$106,412	$0	$0	$0	$0	$0
Miscellaneous	$0	$2,300	$0	$0	$2,956	$0
Total	**$511,718**	**$395,354**	**$697,012**	**$36,226**	**$2,956**	**$300,000**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets						
Total	**$511,718**	**$395,354**	**$697,012**	**$36,226**	**$2,956**	**$300,000**

Table 47 – Historical spending - Key System Service Projects

General Plant

General Plant investments are non-mandatory 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 2014 to 2018 historical years has varied between $131k and $508k.

- 2014 actuals (CGAAP) were $387,068.
- 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 actuals (IFRS) were $508,390. The increase from 2015 of $377,303 was primarily due to the procurement of a large fleet vehicle to replace an existing vehicle that was at end of life.
- 2017 actuals (IFRS) were $459,193. The decrease from 2016 of $49,197 was primarily due to reduced spending on computer hardware and software.
- 2018 actuals (IFRS) were $138,928. The decrease from 2017 of $320,265 was primarily due to reduced spending on transportation equipment.

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

Projects	2014	2015	2016	2017	2018 Bridge Year	2019 Test Year
General Plant						
Computer Hardware						
	$3,654	$53,754	$61,921	$8,527	$8,243	$50,950
Sub-Total	$3,654	$53,754	$61,921	$11,037	$8,243	$50,950
Computer Software						
	$51,314	$12,521	$69,340	$13,999	$8,000	$50,950
Sub-Total	$51,314	$12,521	$69,340	$13,999	$8,000	$50,950
Pole Bunker						
	$0	$0	$0	$0	$0	$175,000
Sub-Total	$0	$0	$0	$0	$0	$175,000
Transportation Equipment						
	$262,918	$39,115	$354,140	$388,939	$113,100	$240,000
Sub-Total	$262,918	$39,115	$354,140	$388,939	$113,100	$240,000
Miscellaneous	$69,182	$25,697	$22,989	$45,218	$9,584	$52,310
Total	**$387,068**	**$131,087**	**$508,390**	**$459,193**	**$138,928**	**$569,210**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets						
Total	**$387,068**	**$131,087**	**$508,390**	**$459,193**	**$138,928**	**$569,210**

Table 48 – Historical spending - Key General Plant investments

5.4.3.1b Impact of system investment on O&M costs 2019 – 2023

EEDO's operations and maintenance strategy is to minimize reactive and emergency-type work through efficient operations and an effective planned maintenance program, including predictive and preventative actions. EEDO's customer responsiveness and system reliability are monitored continually to ensure that its maintenance strategy is effective. This effort is coordinated with EEDO's capital project work so that where maintenance programs have identified matters which require capital investments, EEDO 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. EEDO constantly evaluates its maintenance data to adjust predictive and preventative actions. The ultimate objective is to reduce this emergency maintenance. EEDO uses PowerAssist and Alectra Control Room operations 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 EEDO 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 – EEDO 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 EEDO’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 EEDO’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 EEDO. Engineering costs are 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 EEDO’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 2019 – 2023 period are:

2019	2020	2021	2022	2023
$2,645,000	$2,711,000	$2,856,000	$2,848,000	$2,905,000

Table 49 – 2019 – 2023 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 third party attachment work.

System support expenditures (e.g. GIS, SmartMAP) are expected to provide a better overall understanding of EEDO'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 50 – O&M impacts for significant assets

EEDO's forecast O&M increases during the plan period are predicted to average 2.4% per year.

5.4.3.1c Investment drivers

During the 2019 – 2023 period, EEDO 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 EEDO'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 EEDO'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 2019 -2023 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 prior to 2016. Specific high performance risk areas will be prioritized during the 2019 – 2023 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 2020, 2021 and 2023.
- 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 EEDO'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.

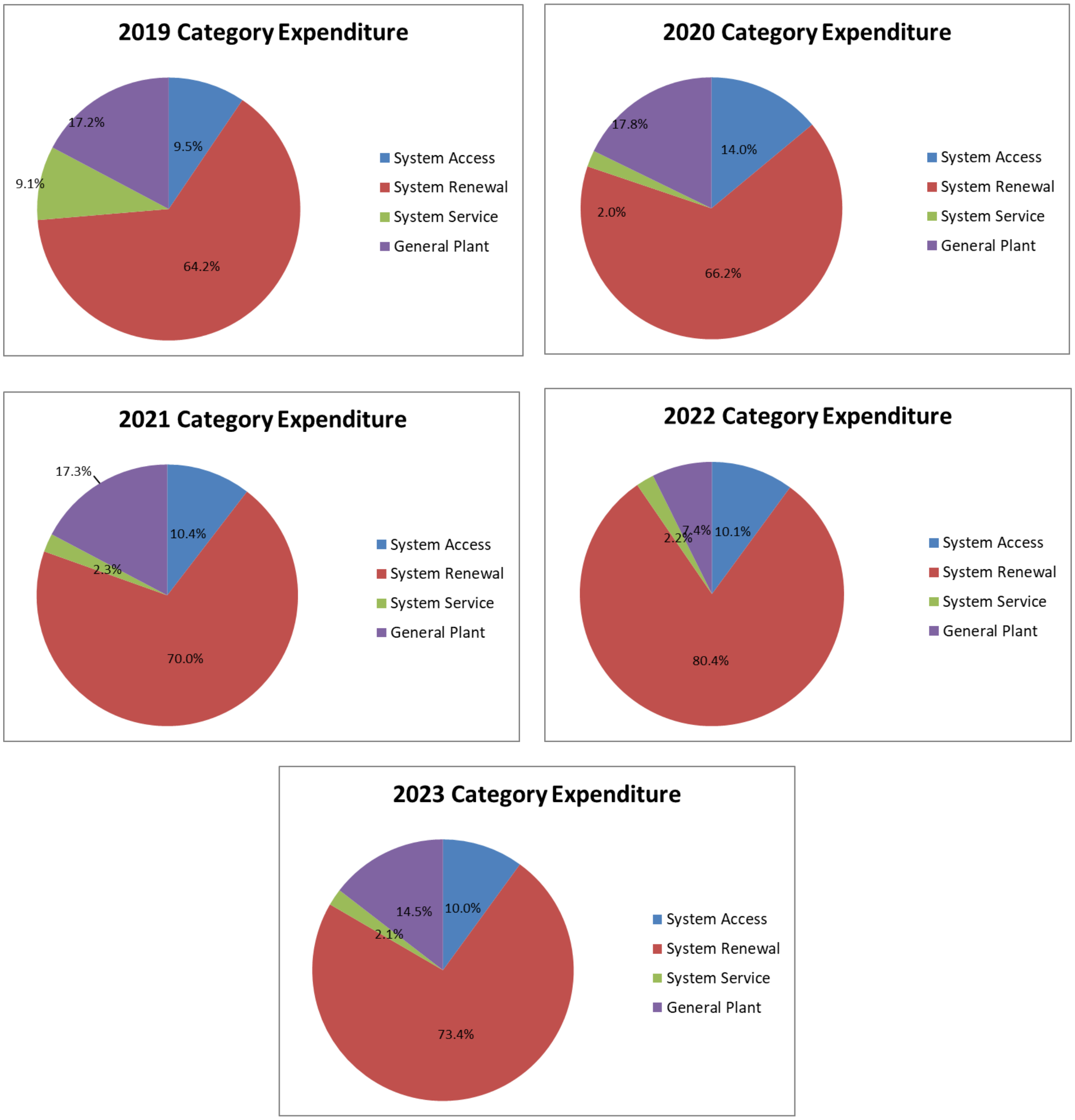


Figure 22 – 2019 – 2023 Capital Expenditure Charts

5.4.3.1d EEDO capability assessment

There is sufficient capacity on the EEDO 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.

5.4.3.2 Material Investments

This section includes the material justification for projects by year from 2019 to 2023.

Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications issued by the Board dated July 12, 2018 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 2019 EEDO Distribution revenue requirement is less than $10 million, and as such the materiality threshold is calculated as being $50,000. EEDO 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. Any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement (CCRA).
3. Related customer attachments and load, as applicable
4. Start date, in-service date and expenditure timing over the planning horizon (2019 – 2023)
5. The risks to the completion of the project or activity as planned and the manner in which such risks will be mitigated
6. Comparative information on expenditures for equivalent projects/activities over the historical period, where available
7. 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. Environmental benefits
6. Conservation and Demand Management

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

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

2019 - 2023 Material Projects

EPCOR Electricity Distribution Ontario Inc.
Capital Project

EPCOR PROVIDING MORE

2019 - 2023

Project Name:	**Annual Customer Additions – multiyear expenditure**
Project #:	
Investment Category:	**System Access**
Investment Type:	**Mandatory**
Service Area:	**Complete Service Territory**

Start Date:	**January 1, 2019**	**In Service Date:**	**Jan 1, 2019 – Dec 31, 2023**
Net Capital Cost: **See below** (Gross – Contributed + O&M)		**Gross Capital Cost:**	**See below**
		Contributed Capital:	**$0**
		O&M Costs:	**$0**

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

A. General Information:

New customer additions – annual program.

Year	Gross	Contributed	Net
2019	$493,221	($419,238)	$ 73,983
2020	$701,936	($427,204)	$274,732
2021	$711,485	($604,762)	$106,723
2022	$731,183	($621,506)	$109,677
2023	$798,801	($678,981)	$119,820

Risks to Completion and Risk Mitigation: Customer schedule change**.** Material and resources available
Comparative Information on Equivalent Historical Projects (if any): This project is similar to previous EEDO connection projects.
Renewable Energy Generation linkage: N/A
Non-distribution system options: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver**: Provide connection supply to new services
	Reliability Planning: to be connected per standard underground or overhead servicing standards
	Priority # N/A – Regulatory requirement and mandatory project, driven by development. Schedule coordinated with customer requirements.
	Investment effectiveness: Ensure compliance with Section 28 of the Electricity Act and customer satisfaction. The costs associated with this project are partially funded by the customer based upon calculated estimates.

Safety	Connection constructed according to Reg 22/04 standards
Cyber Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Environmental benefits	N/A
Conservation and Demand Management	N/A

C. Category-specific requirements: System Access	
Projects/activities in this category are driven by <u>statutory, regulatory or other obligations</u> on the part of the distributor to provide customers with access to their distribution system.	
Factors affecting the Timing/Priority of implementing the project	Mandatory; project timing coordinated with customer schedule for connection
Factors relating to Customer Preferences or input from customers and other third parties	Project completion 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 2019 through 2023
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

EPCOR Electricity Distribution Ontario Inc.
Capital Project

EPCOR PROVIDING MORE

2019 - 2023

Project Name:	**Road relocation work – multiyear expenditure**		
Project #:			
Investment Category:	**System Access**		
Investment Type:	**Mandatory**		
Service Area:	**Complete Service Territory**		
Start Date: January 1, 2019		**In Service Date:**	**Jan 1, 2019 – Dec 31, 2023**
Net Capital Cost: See below (Gross – Contributed + O&M)		**Gross Capital Cost:**	**See below**
		Contributed Capital:	**$0**
		O&M Costs:	**$0**

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

A. General Information:

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

Year	Gross	Contributed Capital	Net
2019	$143,684	($47,895)	$ 95,789
2020	$146,414	($48,805)	$ 97,609
2022	$149,195	($49,732)	$ 99,463
2022	$152,031	($50,677)	$101,452
2023	$167,234	($50,677)	$116,557

Risks to Completion and Risk Mitigation: Overall project timing subject to County/Town schedule.
Comparative Information on Equivalent Historical Projects (if any): This is an annual mandatory program requiring plant relocation due to road rebuilding. Similar to previous pole relocation projects.
Renewable Energy Generation linkage: N/A
Non-distribution system options: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver**: to accommodate County/Town road rebuilding needs
	Reliability Planning: rebuild to current standards for overhead and underground construction
	Priority # N/A – Regulatory requirement and mandatory 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, Interoperability	This work will be coordinated with County/Town schedules and plans
Environmental benefits	N/A
Conservation and Demand Management	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	Mandatory; 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

EPCOR Electricity Distribution Ontario Inc.
Capital Project

2019 - 2023

Project Name:	**Smart Meter Expenditures – multiyear expenditure**		
Project #:			
Investment Category:	**System Access**		
Investment Type:	**Mandatory**		
Service Area:	**Complete Service Territory**		
Start Date:	**January 1, 2019**	**In Service Date:**	**Jan 1, 2019 – Dec 31, 2023**
Net Capital Cost: (Gross – Contributed + O&M)	**See below**	**Gross Capital Cost:**	**See below**
		Contributed Capital:	**$0**
		O&M Costs:	**$0**

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

A. General Information:

Smart Meter capitalization

Year	Net
2019	$142,184
2020	$144,886
2022	$147,638
2022	$150,443
2023	$154,204

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

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver**: Metering hardware for new and existing customers
	Reliability Planning: Meters subject to Measurement Canada certification and testing
	Priority # N/A – Regulatory requirement and mandatory project, driven by residential and commercial meter needs.
	Investment effectiveness: Ensure compliance with Section 28 of the Electricity Act and customer satisfaction.
Safety	Equipment to Reg. 22/04 standards

Cyber Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Environmental benefits	N/A
Conservation and Demand Management	N/A

C. Category-specific requirements: System Access	
Projects/activities in this category are driven by <u>statutory, regulatory or other obligations</u> 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

EPCOR Electricity Distribution Ontario Inc.
Capital Project

EPCOR PROVIDING MORE

2019 - 2023

Project Name:	**Planned and Emergency Pole Replacement Program**		
Project #:			
Investment Category:	**System Renewal**		
Investment Type:	**Mandatory**		
Service Area:	**Complete Service Territory**		
Start Date:	**January 1, 2019**	**In Service Date:**	**Jan 1, 2019 – Dec 31, 2023**
Net Capital Cost: See below		**Gross Capital Cost:**	**See below**
		Contributed Capital:	**$0**
		O&M 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 and the planned replacement of individual poles when it has been determined that they have reached end-of-life.

Poles may fail un-expectantly or be in imminent position to fail and are replaced reactively, as required, in order to maintain the system in its current working state. 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.

End-of-life is determined through various inspection processes and EEDO's asset management program.

Year	Amount
2019	$415,200
2020	$558,096
2021	$568,128
2022	$582,540
2023	$597,104

Risks to Completion and Risk Mitigation: Material and resources available. Emergency locates required. Process in place for this.
Comparative Information on Equivalent Historical Projects (if any): This is a mandatory program. Related spending in previous years. Multi-year program to replace approximately 1200 poles in "very poor"/"poor" condition and those that have failed. Approximately 40 poles per year are addressed through this planned program.

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 and that present a high risk of failure impacting reliability and public/worker safety.
	Reliability Planning: Plant is replaced like-for-like or upgraded to as per plans for the area.
	Priority # NA – Mandatory project – pole selection managed through the EEDO asset management process priority determined through EEDO asset management program
	Investment effectiveness: Plant is replaced like-for-like or upgraded to accommodate future 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
Environmental benefits	N/A
Conservation and Demand Management	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)	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. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level) 5. Value of Customer Impact (high, medium, low)	4. Reduced outages will improve customer satisfaction. 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;	EEDO has the resources and materials in order to ensure project completion on time. Emergency 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 unexpectantly 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	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 to coincide with plans for the area.
Other related information	Multi-year program to replace ~1200 poles in “very poor”/”poor” condition.

EPCOR Electricity Distribution Ontario Inc.
Capital Project

EPCOR PROVIDING MORE

2019 - 2023

Project Name:	**UG primary cable replacement – multiyear program**		
Project #:			
Investment Category:	**System Renewal**		
Investment Type:	**Mandatory**		
Service Area:	**Complete Service Territory**		
Start Date:	**January 1, 2019**	**In Service Date**	**Jan 1, 2019 – Dec 31, 2023**
Net Capital Cost: See below		**Gross Capital Cost:**	**See below**
		Contributed Capital:	**$0**
		O&M Costs:	**$0**

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

A. General Information:

This project involves the replacement of underground primary cable in the 2019 – 2023 timeframe.

Year	Project	Cable (m)	Cost
2019	Mason Road Underground Primary Cable Replacement	825	$171,270
2020	Primary Cable Replacement as required	250	$50,000
2021	Primary Cable Replacement as required	250	$50,000
2022	Primary Cable Replacement as required	335	$67,830
2023	Primary Cable Replacement as required	340	$69,526
	Total	**2,000**	**$408,626**

The underground primary cable that will be replaced through this program has been determined to be at end-of-life through EEDO's asset management program. 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 EEDO'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
	Reliability Planning: all cable will be replaced with 15kV jacketed TR-XLPE cable. Operations at 5kV will result in minimizing electrical insulation stresses thereby potentially achieving an extended life for this type of cable.
	Priority # N/A – Replacement of failed or failing underground cable

<table>
<tr><td></td><td>Investment effectiveness: The underground cables that are assessed at end of life are more prone to failure requiring frequent emergency repairs. New cable will reduce outages to customers and reduce maintenance repair costs.</td></tr>
<tr><td>Safety</td><td>Elimination of faults will reduce stress and asset degradation on circuit components from the transformer station to the customer.</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>Environmental benefits</td><td>N/A</td></tr>
<tr><td>Conservation and Demand Management</td><td>N/A</td></tr>
<tr><td colspan="2">C. Category-specific requirements: System Renewal</td></tr>
<tr><td colspan="2">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>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. Underground cable is in poor to very poor condition. Failure frequency higher than average. 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.
Ranked high in safety value and medium in reliability to customer</td></tr>
<tr><td>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>EEDO has the resources and materials in order to ensure project completion on time.</td></tr>
<tr><td>Consequences for system O&M costs, including the implications for system O&M of not implementing the project</td><td>Cable failures will require contractors to dig splice pits, and crew hours to repair cables.</td></tr>
<tr><td>Reliability and or safety factors</td><td>New cable will be installed per 22/04 standards</td></tr>
<tr><td>Analysis of Project Benefits and Costs with alternative timing, expenditure, mitigation comparisons</td><td>Rate of expenditure balances rate mitigation needs with decreasing asset reliability. Decreasing rate of</td></tr>
</table>

	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

EPCOR Electricity Distribution Ontario Inc.
Capital Project

EPCOR PROVIDING MORE

2019				
Project Name:	**Overhead Pole Line rebuilds**			
Project #:				
Investment Category:	**System Renewal**			
Investment Type:	**Non-Mandatory**			
Service Area:	**Collingwood**			
Start Date:	**January 1, 2019**	**In Service Date:**	**December 31, 2019**	
Net Capital Cost: $1,225,200		**Gross Capital Cost:**	**$1,225,300**	
		Contributed Capital:	**$0**	
		O&M Costs:	**$0**	
Expenditure Timing:	**Q1 $300,000**	**Q2 $325,300**	**Q3 $300,000**	**Q4 $300,000**

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 EEDO's asset management program. 123 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
Heritage Drive - Huron St. to Grain Elevators	23	$210,000
Napier South Rebuild	10	$103,800
Napier North Rebuild	15	$155,700
Market Street - Hume to Market Lane	9	$93,420
Market Lane - St. Marie to St. Paul	6	$62,280
Arthur Street East Pole Line Rebuild (Thornbury)	22	$220,000
Elgin Street (Thornbury) Pole Line Rebuild	12	$120,000
Alfred Street (Thornbury) East & West Pole Line Rebuild	26	$260,000
Total	**123**	**$ 1,225,300**

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

Comparative Information on Equivalent Historical Projects (if any): This is a non-mandatory 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

	Main Driver: These projects are driven by the need to replace assets that have reached End-Of-Life status.

<table>
<tr><td rowspan="3">Efficiency, Customer Value, Reliability</td><td>Reliability Planning: rebuild to current standards for overhead and underground construction</td></tr>
<tr><td>Priority #2019 1 - 7, 13 – Non- Mandatory project priority determined through the EEDO capital prioritization process</td></tr>
<tr><td>Investment effectiveness: Plant is replaced like-for-like or upgraded to accommodate future plans for the area.</td></tr>
<tr><td>Safety</td><td>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>N/A</td></tr>
<tr><td>Co-ordination, Interoperability</td><td>N/A</td></tr>
<tr><td>Environmental benefits</td><td>N/A</td></tr>
<tr><td>Conservation and Demand Management</td><td>N/A</td></tr>
<tr><td colspan="2">C. Category-specific requirements: System Renewal</td></tr>
<tr><td colspan="2">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>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.
Customer surveys show that reliability is ranked high in value to them</td></tr>
<tr><td>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>EEDO 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 unexpectantly 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	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 individual pole replacement program

EPCOR Electricity Distribution Ontario Inc.
Capital Project

2019

Project Name:	**UG primary cable and live-front transformer replacement**		
Project #:			
Investment Category:	**System Renewal**		
Investment Type:	**Non-Mandatory**		
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**
		O&M Costs:	**$0**

Expenditure Timing:	**Q1**	**Q2**	**Q3**	**Q4**
	$57,090	**$134,940**	**$57,090**	**$57,090**

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

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 EEDO 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 EEDO'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
	Reliability Planning: 5kV cable replaced with 15kV jacketed TR-XLPE cable as per standard for new subdivisions, etc. Operations at 5kV will result in minimizing electrical insulation stresses thereby potentially achieving an extended life for this type of cable.
	Priority #2019 8 - 12 – Non-Mandatory project priority determined through the EEDO 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
Environmental benefits	N/A
Conservation and Demand Management	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)	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.

5. Value of Customer Impact (high, medium, low)	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. 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;	EEDO 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. 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

EPCOR Electricity Distribution Ontario Inc.
Capital Project

EPCOR PROVIDING MORE

2019 - 2023

Project Name:	**SCADA and SmartMAP Enhancements multi-year program**		
Project #:			
Investment Category:	**System Service**		
Investment Type:	**Mandatory**		
Service Area:	**Complete Service Territory**		
Start Date:	**January 1, 2019**	**In Service Date:**	**Jan 1, 2019 – Dec 31, 2023**
Net Capital Cost: See below		**Gross Capital Cost:**	**See below**
		Contributed Capital:	**$0**
		O&M Costs:	**$0**

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

A. General Information:

In 2019, EEDO will be replacing their legacy SCADA system with a new system. The existing C3-ilex SCADA system has reached end of life status and EEDO EEDO can no longer obtain software security updates or replacement hardware. Annual expenditures for SCADA and SmartMAP related initiatives in 2020 – 2023.

Year	Amount
2019	$300,000
2020	$75,000
2021	$76,875
2022	$79,181
2023	$81,161

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:** Replace end-of-life SCADA asset and **c**ontinual improvement in Smart Grid capability
	Reliability Planning: Reduces reliability concern with end-of-life asset; real-time telemetry and control enhances resiliency of distribution system
	Priority # N/A: Annual expenditures to maintain software/hardware functionality

	Investment effectiveness: Improved smart grid 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	EEDO to maintain compliance with OEB Cyber-security framework
Co-ordination, Interoperability	N/A
Environmental benefits	
Conservation and Demand Management	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 create system capacity constraints or otherwise adversely impact operations and the delivery of quality distribution services.	
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 (i.e. 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	Mitigates reliability issues with end-of-life asset. Improved system configuration capability; real-time operator information; improved outage response
Factors affecting implementation timing/priority	Subject to annual needs over the 2019 – 2023 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

EPCOR Electricity Distribution Ontario Inc.
Capital Project

EPCOR PROVIDING MORE

2019 - 2023

Project Name:	**General Plant – multiyear program expenditures**		
Project #:			
Investment Category:	**General Plant**		
Investment Type:	**Mandatory**		
Service Area:	**Complete Service Territory**		
Start Date:	**January 1, 2019**	**In Service Date:**	**Jan 1, 2019 – Dec 31, 2023**
Net Capital Cost: See below		**Gross Capital Cost:**	**See below**
		Contributed Capital:	**$0**
		O&M Costs:	**$0**

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

A. General Information:

General plant investments are modifications, replacements or additions to EEDO'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. In this category EEDO has collected General Plant expenditures that while discrete in nature and timing, are expected to accumulate to material levels in a given year. See below:

	2019	**2020**	**2021**	**2022**	**2023**
Office Equipment	$20,380	$20,767	$21,162	$21,564	$22,103
Computer Equipment	$50,950	$51,918	$52,905	$53,910	$55,258
Computer Software	$50,950	$51,918	$52,904	$53,909	$55,257
Measurement & Testing Equipment	$15,000	$15,575	$15,871	$16,173	$16,577
Stores Equipment & Large Tools	$10,000	$10,384	$10,581	$10,782	$11,062
Power Operated Equipment	$5,000	$5,192	$5,291	$5,391	$5,526
Communication Equipment	$1,930	$2,003	$2,041	$2,080	$2,132
Total	$154,210	$157,757	$160,755	$163,809	$167,904

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.
	Reliability Planning: N/A
	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
Environmental benefits	N/A
Conservation and Demand Management	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

EPCOR Electricity Distribution Ontario Inc.
Capital Project

EPCOR PROVIDING MORE

<table>
<tr><th colspan="6">2019</th></tr>
<tr><td>Project Name:</td><td colspan="5">Bunker for Pole Storage at MS#7</td></tr>
<tr><td>Project #:</td><td colspan="5"></td></tr>
<tr><td>Investment Category:</td><td colspan="5">General Plant</td></tr>
<tr><td>Investment Type:</td><td colspan="5">Mandatory</td></tr>
<tr><td>Service Area:</td><td colspan="5">Collingwood</td></tr>
<tr><td>Start Date:</td><td colspan="2">January 1, 2019</td><td>In Service Date:</td><td colspan="2">December 31, 2019</td></tr>
<tr><td colspan="3" rowspan="3">Net Capital Cost: $175,000</td><td>Gross Capital Cost:</td><td colspan="2">$175,000</td></tr>
<tr><td>Contributed Capital:</td><td colspan="2">$0</td></tr>
<tr><td>O&M Costs:</td><td colspan="2">$0</td></tr>
<tr><td>Expenditure Timing:</td><td>Q1
$0</td><td>Q2
$0</td><td>Q3
$0</td><td colspan="2">Q4
$175,000</td></tr>
<tr><td colspan="6">A. General Information:</td></tr>
<tr><td colspan="6">A new pole storage bunker will be constructed at MS#7 in Collingwood. The existing pole storage bunker location is on property owned by the Town of Collingwood. The Town requires the existing bunk location for a water reservoir they are constructing.
Risks to Completion and Risk Mitigation: Material and resources available.
Comparative Information on Equivalent Historical Projects (if any): N/A
Non-distribution system options: N/A</td></tr>
<tr><td colspan="6">B. Investment Evaluation Criteria</td></tr>
<tr><td rowspan="4">Efficiency, Customer Value, Reliability</td><td colspan="5">Main Driver: New space is required for storing poles. Existing location is no longer available.</td></tr>
<tr><td colspan="5">Reliability Planning: N/A</td></tr>
<tr><td colspan="5">Priority # NA – This is considered a mandatory project as the Town (land owner of the current storage location) has provided notice to EEDO to vacate the property.</td></tr>
<tr><td colspan="5">Investment effectiveness: The new pole bunker will be constructed on property owned by EEDO.</td></tr>
<tr><td>Safety</td><td colspan="5">The existing pole bunker is over 30 years old and not considered up to current safety standards. The new bunker will be built to current safety standards.</td></tr>
<tr><td>Cyber Security, Privacy</td><td colspan="5">N/A</td></tr>
<tr><td>Co-ordination, Interoperability</td><td colspan="5">N/A</td></tr>
<tr><td>Environmental benefits</td><td colspan="5">N/A</td></tr>
<tr><td>Conservation and Demand Management</td><td colspan="5">N/A</td></tr>
</table>

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	N/A - Mandatory
Project Analysis - Risk Assessment -impact of “do nothing” scenario -include monetary consequence, if applicable	N/A - Mandatory
High cost material projects business case details (>$250k)	N/A
Other related information	N/A

EPCOR Electricity Distribution Ontario Inc.
Capital Project

EPCOR PROVIDING MORE

2019 - 2023

Project Name:	**Purchase of multiple fleet units 2019-2023**		
Project #:			
Investment Category:	**General Plant**		
Investment Type:	**Non-Mandatory**		
Service Area:	**Complete Service Territory**		
Start Date:	**January 1, 2019**	**In Service Date:**	**Jan 1, 2019 – Dec 31, 2023**
Net Capital Cost: See below		**Gross Capital Cost:**	**See below**
		Contributed Capital:	**$0**
		O&M Costs:	**$0**

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

A. General Information:

New fleet units are to be procured to replace existing fleet units which has been assessed at economic end-of –life. Repairs and maintenance costs of existing units are expected to remain high with continued operation. New fleet units will have reduced repair and maintenance costs.

	2019	**2020**	**2021**	**2022**	**2023**
Bucket Trucks/Digger Derricks	$0	$500,000	$425,000	$0	$400,000
Tension Stringing Machine	$70,000	$0	$0	$0	$0
Dump Trailer	$25,000	$0	$0	$0	$0
Pickups	$110,000	$0	$0	$100,000	$0
Passenger Vehicles	$35,000	$0	$0	$0	$0
Total	**$240,000**	**$500,000**	**$425,000**	**$100,000**	**$400,000**

Risks to Completion and Risk Mitigation: Delivery subject to manufacturer schedule.
Comparative Information on Equivalent Historical Projects (if any): Variability in unit cost subject to unit complexity and currency exchange rates for units procured outside Canada
Non-distribution system options: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver:** Replacement of aging fleet assets.
	Reliability Planning: N/A
	Priority # 2019 14-17, 2020 – 8, 2021 – 11, 2022 – 10-11, 2023 – 8 – Non-Mandatory project priority determined through the EEDO capital prioritization process

	Investment effectiveness: The proposed fleet units for replacement have reached the end of economic useful life. Reduced operating and maintenance expenses are expected.
Safety	The replaced units will be matched to the work requirements and will reduce the risk of improper work methods. The timing for fleet replacement ensures that units are replaced before they deteriorate to a degree that represents an operational safety hazard.
Cyber Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Environmental benefits	New large fleet units (i.e. bucket trucks) will be capable of using biodiesel fuel as applicable
Conservation and Demand Management	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 Potential for increased maintenance and fuel costs; reduced reliability
High cost material projects business case details (>$250k)	See attached business cases
Other related information	N/A

Vehicle Replacement Assessment Guidelines

Assessment Year	2019	
Unit #	14-04	
Year	2004	
Description	Ford - 1 Ton Dump Truck	
Classification	Heavy	Light or Heavy
Original Cost	$45,030	
Odometer	59,806	
Engine Hours	708	

Variable	Point Allocation	Performance factors	Points
Age	1 point for each year of age	x years	15
Kilometers	1 point for each 25,000 km of use	xxxxx km	2.39
Engine Hours	1 point for each equivalent 25,000km of use (1 engine hour ~ 50km)	x hrs	1.42
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
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
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
Condition	1, 3 or 5 points based on body condition, rust, interior condition, accident history , anticipated repairs,etc. (ie.		4
Other	1 - 5 points for any other condition criteria not covered above		3
	Total Points		**32.81**

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 on year of proposed aqusition	**33**

Notes

It has been determined that a better use of for this vehicle in the future will be to replace the existing dump truck with a heavy duty dump style trailer in the future.

Vehicle Replacement Assessment Guidelines

Aqusition Year	**2019**	
Unit #	36-06	
Year	2006	
Description	Dodge Caravan	
Classification	Light	Light or Heavy
Original Cost	$26,550	
Odometer	74,809	
Engine Hours	674	

Variable	Point Allocation	Performance factors	Points
Age	1 point for each year of age	x years	13
Kilometers	1 point for each 25,000 km of use	xxxxx km	2.99
Engine Hours	1 point for each equivalent 25,000km of use (1 engine hour ~ 50km)	x hrs	1.35
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
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)		5
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)		4
Condition	1, 3 or 5 points based on body condition, rust, interior condition, accident history , anticipated repairs,etc. (ie.		5
Other	1 - 5 points for any other condition criteria not covered above		4
	Total Points		**38.34**

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 on year of proposed aqusition **39**

Notes

Vehicle Replacement Assessment Guidelines

Aqusition Year	**2019**		
Unit #	31-14		
Year	2014		
Description	Dodge - 1/2 Ton Pick-up Truck		
Classification	Light	Light or Heavy	
Original Cost	$43,849		
Odometer	108,160		
Engine Hours	4617		

Variable	Point Allocation	Performance factors	2019
Age	1 point for each year of age	x years	5
Kilometers	1 point for each 25,000 km of use	xxxxx km	4.33
Engine Hours	1 point for each equivalent 25,000km of use (1 engine hour ~ 50km)	x hrs	9.23
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
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)		3
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
Condition	1, 3 or 5 points based on body condition, rust, interior condition, accident history , anticipated repairs,etc. (ie.		2
Other	1 - 5 points for any other condition criteria not covered above		1
	Total Points		**30.56**

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 on year of proposed aqusition	**31**

Notes

Vehicle Replacement Assessment Guidelines

Assessment Year	**2019**	
Unit #	34-14	
Year	2014	
Description	Ford - 3/4 Ton Pick-up Truck	
Classification	Light	Light or Heavy
Original Cost	$48,125	
Odometer	93,988	
Engine Hours	5289	

Variable	**Point Allocation**	**Performance factors**	**2019**
Age	1 point for each year of age	x years	5
Kilometers	1 point for each 25,000 km of use	xxxxx km	3.76
Engine Hours	1 point for each equivalent 25,000km of use (1 engine hour ~ 50km)	x hrs	10.58
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)		5
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)		3
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
Condition	1, 3 or 5 points based on body condition, rust, interior condition, accident history , anticipated repairs,etc. (ie.		3
Other	1 - 5 points for any other condition criteria not covered above		2
	Total Points		**35.34**

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 on year of proposed aquisition **35**

Notes

Vehicle Replacement Assessment Guidelines

Assessment Year	**2020**	
Unit #	33-12	
Year	2012	
Description	Freightliner - Dbl Bucket Truck	
Classification	Heavy	Light or Heavy
Original Cost	$421,000	
Odometer	65,020	
Engine Hours	6630	

Variable	Point Allocation	Performance factors	2020
Age	1 point for each year of age	x years	9
Kilometers	1 point for each 25,000 km of use	xxxxx km	3
Engine Hours	1 point for each equivalent 25,000km of use (1 engine hour ~ 50km)	x hrs	14
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)		4
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
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
Condition	1, 3 or 5 points based on body condition, rust, interior condition, accident history , anticipated repairs,etc. (ie.		1
Other	1 - 5 points for any other condition criteria not covered above		2
	Total Points		**37**

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 on year of proposed aqusition	**37**

Notes

Vehicle Replacement Assessment Guidelines

Aqusition Year	**2021**
Unit #	18-15
Year	2015
Description	Freightligner - Single Bucket Truck
Classification	Heavy (Light or Heavy)
Original Cost	$375,000
Odometer	71,666
Engine Hours	4106

Variable	Point Allocation	Performance factors	2021
Age	1 point for each year of age	x years	6
Kilometers	1 point for each 25,000 km of use	xxxxx km	3.5
Engine Hours	1 point for each equivalent 25,000km of use (1 engine hour ~ 50km)	x hrs	9.5
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)		5
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
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
Condition	1, 3 or 5 points based on body condition, rust, interior condition, accident history , anticipated repairs,etc. (ie.		1
Other	1 - 5 points for any other condition criteria not covered above		2
	Total Points		**31**

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 on year of proposed aqusition **31**

Notes

Vehicle Replacement Assessment Guidelines

Aqusition Year	**2022**
Unit #	11-15
Year	2015
Description	Ford - 1/2 Ton Pick-up Truck
Classification	Light
Original Cost	$39,126
Odometer	49,844
Engine Hours	2532

Light or Heavy

Variable	Point Allocation	Performance factors	2022
Age	1 point for each year of age	x years	7
Kilometers	1 point for each 25,000 km of use	xxxxx km	3
Engine Hours	1 point for each equivalent 25,000km of use (1 engine hour ~ 50km)	x hrs	6.5
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)		5
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
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
Condition	1, 3 or 5 points based on body condition, rust, interior condition, accident history , anticipated repairs,etc. (ie.		3
Other	1 - 5 points for any other condition criteria not covered above		1
	Total Points		**30.5**

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 on year of proposed aqusition | **30**

Notes

Vehicle Replacement Assessment Guidelines

Aqusition Year	**2022**	
Unit #	32-14	
Year	2014	
Description	Dodge - 1/2 Ton Pick-up Truck	
Classification	Light	Light or Heavy
Original Cost	$43,849	
Odometer	129,034	
Engine Hours	3119	

Variable	**Point Allocation**	**Performance factors**	**2022**
Age	1 point for each year of age	x years	8
Kilometers	1 point for each 25,000 km of use	xxxxx km	8
Engine Hours	1 point for each equivalent 25,000km of use (1 engine hour ~ 50km)	x hrs	9
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)		5
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)		3
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
Condition	1, 3 or 5 points based on body condition, rust, interior condition, accident history , anticipated repairs,etc. (ie.		2
Other	1 - 5 points for any other condition criteria not covered above		1
	Total Points		**39**

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 on year of proposed aqusition **39**

Notes

Vehicle Replacement Assessment Guidelines

Aqusition Year	**2023**	
Unit #	30-10	
Year	2010	
Description	Internation - Line Truck	
Classification	Heavy	Light or Heavy
Original Cost	$405,125	
Odometer	18,560	
Engine Hours	1542	

Variable	**Point Allocation**	**Performance factors**	**2023**
Age	1 point for each year of age	x years	13
Kilometers	1 point for each 25,000 km of use	xxxxx km	3
Engine Hours	1 point for each equivalent 25,000km of use (1 engine hour ~ 50km)	x hrs	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)		2
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
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
Condition	1, 3 or 5 points based on body condition, rust, interior condition, accident history , anticipated repairs,etc. (ie.		2
Other	1 - 5 points for any other condition criteria not covered above		2
	Total Points		**29**

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 on year of proposed aqusition	**29**

Notes

EPCOR Electricity Distribution Ontario Inc.
Capital Project

EPCOR PROVIDING MORE

2020

Project Name:	**Overhead Pole Line rebuilds**		
Project #:			
Investment Category:	**System Renewal**		
Investment Type:	**Non-Mandatory**		
Service Area:	**Collingwood**		
Start Date:	**January 1, 2020**	**In Service Date:**	**December 31, 2020**
Net Capital Cost: $1,841,717		**Gross Capital Cost:**	**$1,841,717**
		Contributed Capital:	**$0**
		O&M Costs:	**$0**

Expenditure Timing:	**Q1**	**Q2**	**Q3**	**Q4**
	$400,000	**$600,000**	**$600,000**	**$241,717**

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 EEDO’s asset management program. 132 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
MS1 (Stayner) - Brock Street Rebuild - Part 3	36	$502,286
First Street Ext. Pole Line Rebuild (Old Mountain Rd to High St.)	9	$125,572
Fourth Street Pole Line Rebuild (Hickory St. - Pine St.)	25	$348,810
High Street Pole Line Rebuild (Murray Court To Fifth St.)	20	$279,048
Oliver Crescent Pole Line Rebuild	12	$167,429
Rodney St. Pole Line Rebuild (Peel St. - Huron St.)	10	$139,524
Third Street Pole Line Rebuild (Spruce St. - Birch St.)	20	$279,048
Total	**132**	**$1,841,717**

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

Comparative Information on Equivalent Historical Projects (if any): This is a non-mandatory 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

	Main Driver: These projects are driven by the need to replace assets that have reached End-Of-Life status.

Efficiency, Customer Value, Reliability	**Reliability Planning:** rebuild to current standards for overhead and underground construction	
	Priority # 2020 1 - 7 – Non- Mandatory project priority determined through the EEDO capital prioritization process	
	Investment effectiveness: Plant is replaced like-for-like or upgraded to accommodate future 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	
Environmental benefits	N/A	
Conservation and Demand Management	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. 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;	EEDO 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 not implementing the project	N/A – EOL equipment may fail unexpectantly 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	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 individual pole replacement program

EPCOR Electricity Distribution Ontario Inc.
Capital Project

EPCOR PROVIDING MORE

2021

Project Name:	**Overhead Pole Line rebuilds**		
Project #:			
Investment Category:	**System Renewal**		
Investment Type:	**Non-Mandatory**		
Service Area:	**Collingwood**		
Start Date: January 1, 2021		**In Service Date:**	**December 31, 2021**
Net Capital Cost: $1,755,901		**Gross Capital Cost:**	**$1,755,901**
		Contributed Capital:	**$0**
		O&M Costs:	**$0**

Expenditure Timing:	**Q1**	**Q2**	**Q3**	**Q4**
	$400,000	**$500,000**	**$500,000**	**$355,901**

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 EEDO's asset management program. 151 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 (Raglan to Peel)	15	$213,048
Mountain Road - 10th Line to Osler (Remove old 44kv Circuit)	70	$250,000
Oak/Ferguson Rear lot	7	$220,505
Hurontario n/o Simcoe Street Rear lot rebuild	7	$114,336
Hurontario East- North & South of Third Street	12	$170,438
Mason/Dickson Rear Lot	9	$220,505
Park/Ferguson Road Rear Lot	9	$220,505
Clarkson/Oak Rear lot	7	$114,336
Oak/Dickson Rear lot	9	$147,003
St. Marie Street - Hume to Hamilton	6	$ 85,219
Total	**151**	**$1,755,901**

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

Comparative Information on Equivalent Historical Projects (if any): This is a non-mandatory 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.
	Reliability Planning: rebuild to current standards for overhead and underground construction
	Priority # 2021 1 - 10 – Non- Mandatory project priority determined through the EEDO capital prioritization process
	Investment effectiveness: Plant is replaced like-for-like or upgraded to accommodate future 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
Environmental benefits	N/A
Conservation and Demand Management	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. 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;	EEDO 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 not implementing the project	N/A – EOL equipment may fail unexpectantly 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	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 individual pole replacement program

EPCOR Electricity Distribution Ontario Inc.
Capital Project

EPCOR PROVIDING MORE

2022

Project Name:	**Overhead Pole Line rebuilds**		
Project #:			
Investment Category:	**System Renewal**		
Investment Type:	**Non-Mandatory**		
Service Area:	**Collingwood**		
Start Date:	**January 1, 2022**	**In Service Date:**	**December 31, 2022**
Net Capital Cost: $ 2,230,676		**Gross Capital Cost:**	**$ 2,230,676**
		Contributed Capital:	**$0**
		O&M Costs:	**$0**

Expenditure Timing:	**Q1**	**Q2**	**Q3**	**Q4**
	$530,684	**$600,000**	**$600,000**	**$500,000**

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 EEDO's asset management program. 119 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
Osler Bluff Feeder Tie	26	$352,370
Laneway East of Hurontario Between Simcoe & Huron	10	$199,500
Park Rd. / East of Trail - Rear Lot	4	$293,272
Clarkson Crescent West - Rear Lot	4	$293,272
Robinson Street - Hume to Collins	24	$349,524
Campbell Street - Herrington Court to High Street	10	$145,635
Elizabeth Street West	16	$233,016
Collingwood Street - Wellington St. W to Louisa St	17	$247,580
Wellington Street West - Mill St to Collingwood St.	8	$116,508
Total	**119**	**$ 2,230,676**

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

Comparative Information on Equivalent Historical Projects (if any): This is a non-mandatory 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.	
	Reliability Planning: rebuild to current standards for overhead and underground construction	
	Priority # 2022 1 - 9 – Non- Mandatory project priority determined through the EEDO capital prioritization process	
	Investment effectiveness: Plant is replaced like-for-like or upgraded to accommodate future 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	
Environmental benefits	N/A	
Conservation and Demand Management	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. 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;	EEDO 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 not implementing the project	N/A – EOL equipment may fail unexpectantly 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	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 individual pole replacement program

EPCOR Electricity Distribution Ontario Inc.
Capital Project

2023

Project Name:	**Overhead Pole Line rebuilds**		
Project #:			
Investment Category:	**System Renewal**		
Investment Type:	**Non-Mandatory**		
Service Area:	**Collingwood**		
Start Date: January 1, 2023		**In Service Date:**	**December 31, 2023**
Net Capital Cost: $2,198,557		**Gross Capital Cost:**	**$2,198,557**
		Contributed Capital:	**$0**
		O&M Costs:	**$0**

Expenditure Timing:	**Q1**	**Q2**	**Q3**	**Q4**
	$529,150	**$550,000**	**$550,000**	**$500,000**

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 EEDO's asset management program. 154 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
Mill Street – Louisa Street to George Street	34	$495,159
Edward Street - Mary to Collingwood	21	$305,834
George Street - Mill Street to east end	36	$524,286
Caroline Street E&W – Mary St to Sarah St	28	$407,778
Valleyfield	10	$133,000
Montreal Street	17	$226,100
Johnston Street	8	$106,400
Total	**154**	**$2,198,557**

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

Comparative Information on Equivalent Historical Projects (if any): This is a non-mandatory 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

	Main Driver: These projects are driven by the need to replace assets that have reached End-Of-Life status.

Efficiency, Customer Value, Reliability	**Reliability Planning:** rebuild to current standards for overhead and underground construction
	Priority # 2023 1 - 7 – Non- Mandatory project priority determined through the EEDO capital prioritization process
	Investment effectiveness: Plant is replaced like-for-like or upgraded to accommodate future 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
Environmental benefits	N/A
Conservation and Demand Management	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. 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;	EEDO 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 not implementing the project	N/A – EOL equipment may fail unexpectantly 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	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 individual pole replacement program

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			

EPCOR

EPCOR - 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:________________________

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

		EEDO Station DG Capacity							
								MS (HONI CALC)	
Model	TS Supply	Station	Feeder	Voltage	Max KVA	Min KVA	Peak	TX Size KVA	Capacity KVA
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

Collingwood Small Business Consultation – October 18, 2017

Attendee Business Category

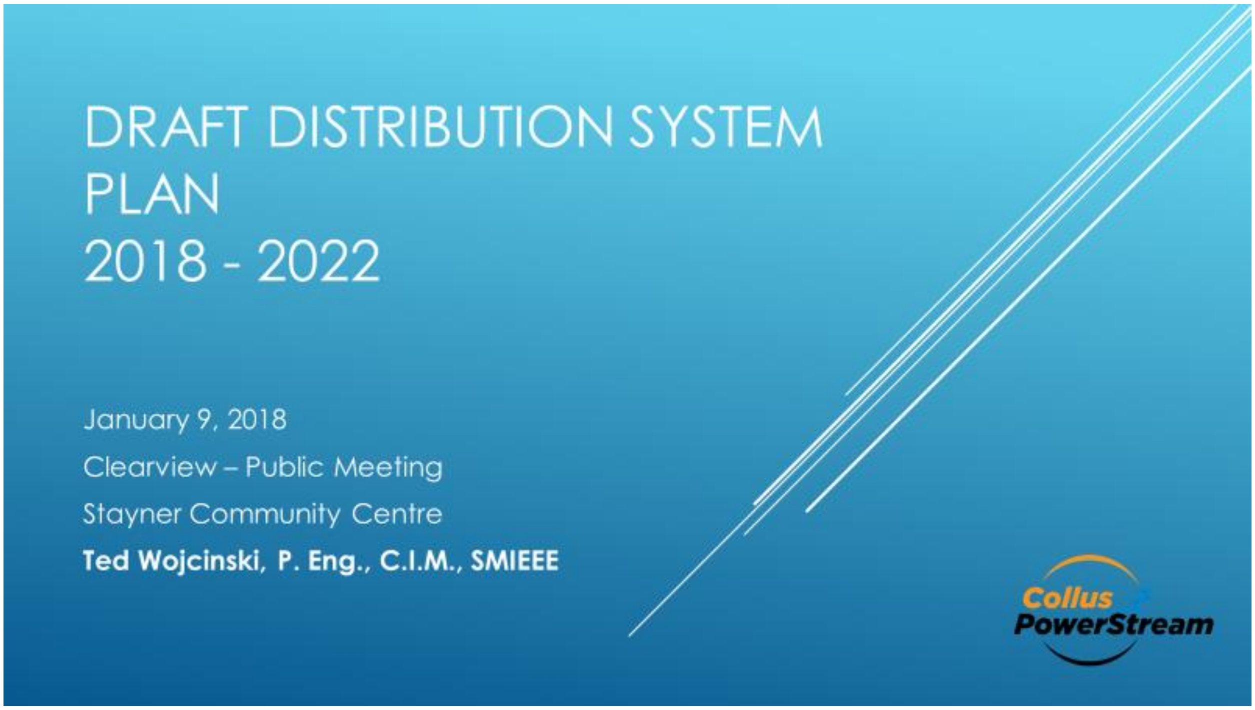
Hospitality	2
Technology	2
Financial Sales	2
Insurance Sales	1
Chamber of Commerce	1
Business Association	1
Land Developer	1
Communications	1
Government	1
Home Business	1
Real Estate	1
Health / Wellness	1
Did not Provide	5
Total =	**20**

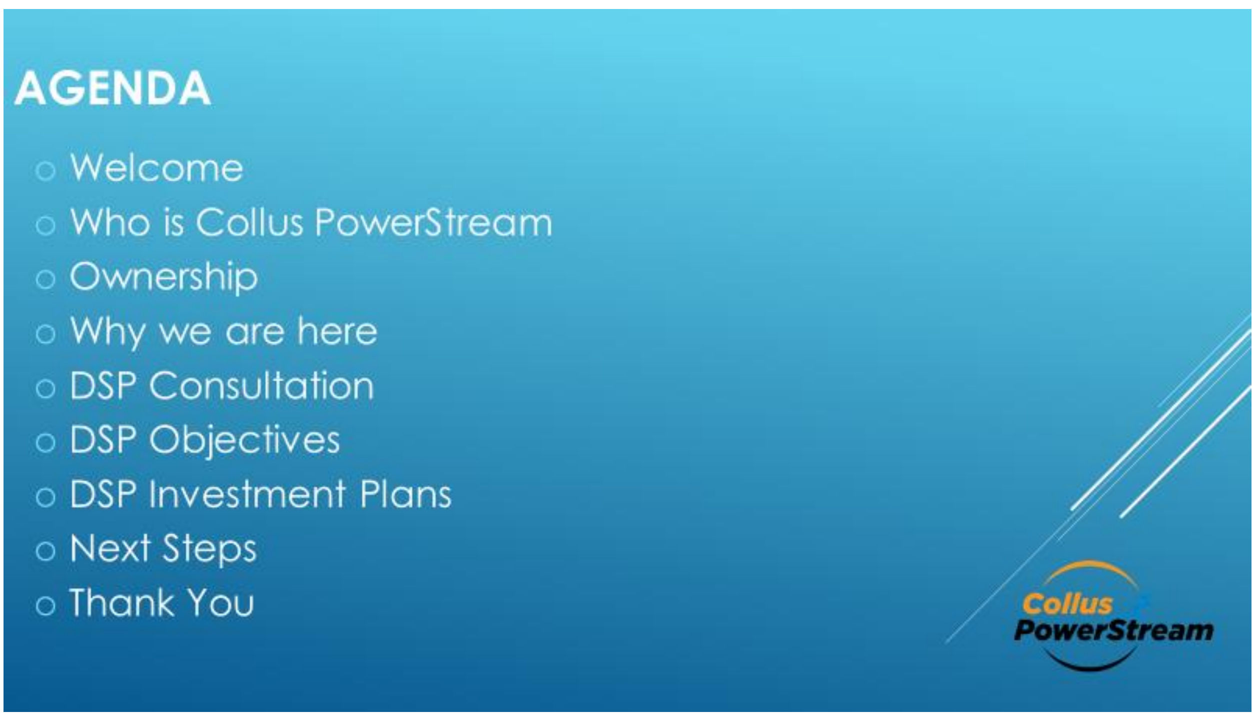
Question No.	Question	Agree strongly	Agree somewhat	Neither agree or disagree	Disagree somewhat	Disagree strongly	TOTAL
Q1.	Keeping rates low and maintaining reliable service is a key outcome of the DSP. This will result in value to you and your business.	16	4	0	0	0	**20**
Q2.	The objectives of the DSP (Safety, Reliability, Customer Service, Financial Integrity, Effective Integration, Environment and CDM) describe what CPC stands for and what it is trying to achieve over the period of the DSP. These objectives will ensure services are provided in a manner that meets the needs, priorities and preferences of CPC customers.	17	3	0	0	0	**20**
Q3.	The 2018 Capital and Maintenance investment plans, at a high level, meet your expectations about how CPC intends to manage its assets.	9	10	1	0	0	**20**
Q4.	The information presented in this DSP consultation was of sufficient scale and scope to help you understand the basics of CPC's 2018 – 2022 DSP.	10	8	2	0	0	**20**

Comments

Not sure why my opinion matters. How can what I say make a difference. It seems like everything has already been decided.
Great Organization. Keep up the good work.
Presentation should link how DSP will impact rates. Does CPC earn enough to cover planned capital expenditures. Or does rates have to increase?
Great Presentation
What are the consequences on the 5-year plan on 2023 cost of hydro?
I have a much better understanding
Need more clarity about effect on user rates. i.e. % increases
End user education on how to access your individual consumption on-line.

Appendix E


DRAFT DISTRIBUTION SYSTEM PLAN
2018 - 2022
January 9, 2018
Clearview – Public Meeting
Stayner Community Centre
Ted Wojcinski, P. Eng., C.I.M., SMIEEE
Collus PowerStream


AGENDA
Welcome
Who is Collus PowerStream
Ownership
Why we are here
DSP Consultation
DSP Objectives
DSP Investment Plans
Next Steps
Thank You
Collus PowerStream

WELCOME

- Ted Wojcinski – DSP Consultant
- Larry Irwin – VP, Collus PowerStream
- Support Staff

Collus PowerStream

WHO IS COLLUS POWERSTREAM

- Licensed electricity distributor to provide electricity distribution services in **Collingwood**, **Stayner**, **Creemore** and **Thornbury**
- Responsible for maintaining over 354 km distribution lines and associated infrastructure over 45 square kilometers
- Mission = Our business provides people with the energy for success and the necessities of life.
- Staff of 33
- On the Web www.collus.com
- On Twitter @CollusPower

Service Connections	
Collingwood	13,330
Stayner	1,988
Thornbury	1,565
Creemore	657
Total =	**17,540**

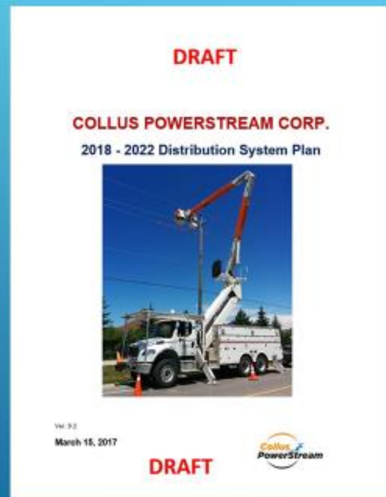
Collus PowerStream


CURRENT OWNERSHIP
Incorporated under the Ontario Business Corporations Act.
Owned 50% by the Town of Collingwood and 50 % owned by Alectra Inc.
PowerStream Inc. purchased their 50% interest on July 31, 2012 (MADD application approved by OEB July 12, 2012).
COLLINGWOOD
Power Stream
alectra utilities
50%
50%
Collus PowerStream
Collus PowerStream


FUTURE OWNERSHIP
Step 1.
50%
Sells Shares
50%
COLLINGWOOD
Power Stream
alectra
Collus PowerStream
Step 2.
100%
Sells Shares
COLLINGWOOD
EPCOR
Collus PowerStream
Collingwood, Alectra and EPCOR Submitted MADD application to OEB on Dec 22, 2017
Future LDC
EPCOR
Collus PowerStream

WHY WE ARE HERE

- All distributors must file a Distribution System Plan (DSP) when filing a Cost of Service (COS) rate application.
- Next COS anticipated in 2018
- This will be Collus PowerStream's 1st DSP submission to the OEB
- DSP describes asset management practices and capital expenditure plans over next 5-years (2018–2022)
- DSP must demonstrate services which are provided in a manner that responds to identified customer needs, priorities and preferences.


DRAFT

COLLUS POWERSTREAM CORP.

2018 - 2022 Distribution System Plan

March 15, 2017

DRAFT

Collus PowerStream

DSP CONSULTATION

Draft DSP has been guided by customer feedback that have consistently indicated :

Low rates and **Maintaining** **reliable service** are key concerns.

As a Customer or Stakeholder we want to:

- Seek your views on our draft DSP
- Provide more information where required
- Modify the plan based on feedback received
- **Your Opinion Matters !!!**

Collus PowerStream

DSP OBJECTIVES

Safety - Construct, Maintain & Operate Assets in a Safe Manor

Reliability - Monitoring Asset Conditions

Customer Service - Managing Customer Expectations

Financial Integrity - Manage investment planning to mitigate rate impacts.

Effective Integration - Continued Improvement of processes & practices

Environmental - Environment Stewardship

CDM - CDM Targets

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**

Collus PowerStream

SAFETY

- Safety is our highest priority
- Assets (poles, wires, transformers, etc.) can be seen on every street and it is imperative this infrastructure functions properly and the public are not put at risk.
- Improving public awareness of electrical safety is also key to ensuring that the public is kept safe..

Collus PowerStream

RELIABILITY

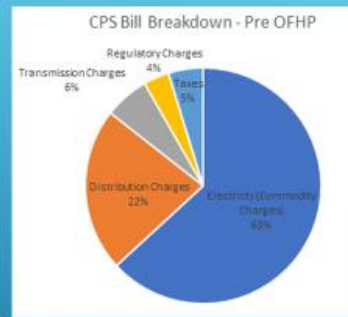
- Comprehensive inspection, maintenance and replacement programs, on a scheduled basis.
  - Ensures assets can be managed so that the ongoing maintaining and repairing does not exceed the cost replacing.
  - Ensures reliability does not suffer.

CUSTOMER SERVICE

- 74% of respondents to our most recent Customer Satisfaction survey said they were 'very satisfied' with their most recent experience with CPC staff.
- Asset investment plans need to align with customer expectations for reliability, restoration, customer service and overall value.

FINANCIAL INTEGRITY

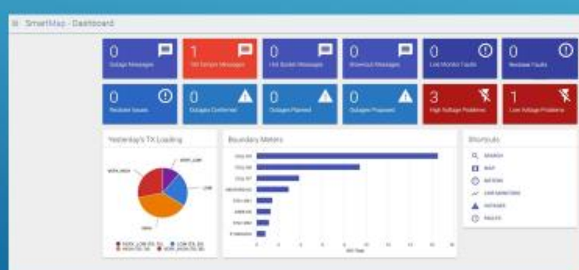
- Ability to sustainably invest in distribution system for access, service and renewal are key.
- CPC's controllable portion of the customer bill is less than 25%.
- Investment plans are prioritized and timed depending on their individual value.



EFFECTIVE INTEGRATION

- Ensures that continual improvement of processes and practices rank high in consideration of program development and deliverables.

On March 27th, 2017, together with Essex Powerlines Collus PowerStream was awarded the "Innovation Excellence" Award for our joint submission "Digital Grid 2.0" at the Electrical Distributors Association annual general meeting.



ENVIRONMENTAL

- CPC strives to set a good example as a steward of the environment.
- Environmental impacts are considered in the design, construction and operation of the distribution system. (i.e. procuring and operating equipment that minimizes potential environmental impacts such as greenhouse gas emissions).
- CPC also promotes the facilitation of Renewable Generation connection to our distribution system.

Collus PowerStream

CDM

- Delivery of the CDM programs supports public policy objective of electricity conservation

Residential Programs

Large Business Programs

Michael Jackson GM
Retrofit Program

Project: Parking light upgraded to energy-efficient LEDs
Incentive: $21,626
Energy Savings: over 144,000 kWh annually

Small Business Programs

The Huron Club
Business Refrigeration Incentive

Project: Received new energy efficient motors in the restaurant's fridges and freezer
Received FREE Upgrades: $2,053
Annual Electricity Savings: $1,785

Canadian Mist Distillery
Retrofit Program

Project: Installation of VFD controls on the Distillery's North Process Water Pump (150 HP) and Grain Dryer.
Incentive: $41,318.46
Energy Savings: over 507,000 kWh

Collus PowerStream

DSP INVESTMENT PLANS

- **Capital investment plans** result in new additions of equipment (poles, wire, cable, etc.) to the distribution system. Additions can be new installations or replacement installation for existing equipment that has failed/reached end of life and needs to be replaced. Capital additions provide future benefits (i.e. delivery of power) to customers over the lifespan of the asset.

- **Maintenance investment plans** result in expenditures on existing plant and equipment that are designed to optimize the life (maximize) and ongoing cost (minimize) of the particular asset. Maintenance keeps the asset in good working order.

Collus PowerStream

CAPITAL INVESTMENT – CATEGORIES & TYPES

System Access	System Renewal	System Service	General Plant
Mandatory	Non-Mandatory	Non-Mandatory	Non-Mandatory

Modifications to the distribution system to provide a customer(s) with access to electricity services via the distribution system	Replacing or refurbishing assets on an ongoing basis to mitigate equipment failure and reliability impacts	Modifications or enhancements to the distribution system to optimize system performance and eliminate growth related constraints	Support investments required for day to day business and operations activities (i.e. computer systems, fleet vehicles, tools, etc.)

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2018 – 2022 CAPITAL FORECAST

Draft DSP proposed capital investment for the 2018 – 2022 period as follows:

Category	2017	2018	2019	2020	2021	2022	Total
			Mandatory				
System Access	$303,033	$581,270	$312,000	$318,000	$324,000	$330,000	**$1,865,000**
			Non-Mandatory				
System Renewal	$2,115,500	$1,895,340	$2,528,000	$2,283,000	$2,339,000	$2,562,000	**$11,607,000**
System Service	$51,087	$51,087	$52,000	$53,000	$54,000	$55,000	**$265,000**
General Plant	$626,334	$651,930	$365,000	$658,000	$586,000	$299,000	**$2,587,000**
Total	**$3,095,954**	**$3,179,627**	**$3,256,000**	**$3,312,000**	**$3,303,000**	**$3,246,000**	**$16,297,000**
% over Prev. Yr.		**2.70%**	**2.40%**	**1.72%**	**-.27%**	**-1.73**	

2018 – CAPITAL BREAKDOWN

System Access	
New Customer connections/initiated	$484,025
New Metering	$139,533
Misc. Road Authority work	$141,005
7th & 8th Streets Projects - Collingwood	*$275,130*
Capital Contributions	-$458,423
Total =	**$581,270**

System Renewal	
End of Life Pole changes (Individual)	$305,700
Emergency pole changes (Storms etc.)	$101,900
Pole Line Rebuilds Projects (7 Locations)	$1,487,740
Total =	**$1,895,340**

System Service	
SCADA, SmartMAP etc.	$51,087
Total =	**$51,087**

General Plant	
70' Bucket truck	$500,000
Computer Hardware/Software	$100,000
Measurement & Testing Equipment	$31,930
Office Equipment	$20,000
Total =	**$651,930**

Combined Total
$3,179.627

2018 - MAINTENANCE INVESTMENT

CPC has in place proactive inspection and maintenance programs to ensure that equipment is in good operating condition.
Key 2018 programs in this area are:

Project/Activity	Cost
44kV, 8kV, 4kV system maintenance	$1,340,000
Meter Maintenance	$279,000
Line Clearing (Tree Trimming)	$152,000
Distribution station maintenance	$73,000
Total =	**$1,844,000**

This level of effort will ensure assets continue to operate within historical performance parameters.

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DSP - PUBLIC ENGAGEMENT

- Collus Website since June
- Online Survey (June 14th to Dec 1st)
- Chamber Business Meeting
- Stayner, Thornbury and Collingwood PICs
- Misc. Newspaper Postings

1623 Visits

354 Visits

277

635

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NEXT STEPS

- Continue to review & enhance Draft DSP based on feedback. Example Draft DSP now includes proposed increases by %
- Online at www.colluspowerstream.ca/dsp
- Welcome feedback (Positive or Negative)
- Propose to submit Final DSP as part of our Cost of Service filing to OEB in Aug 2018

Collus PowerStream

THANK YOU

www.collus.com
Twitter @CollusPower
705-445-1800

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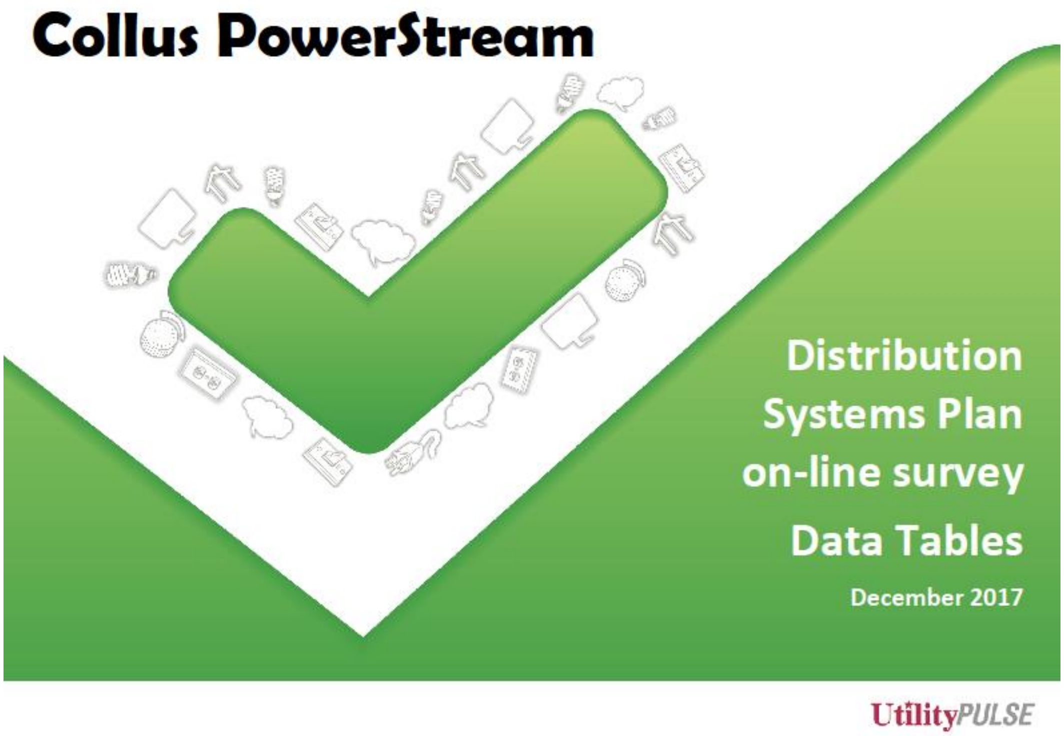
Appendix F


Collus PowerStream
Distribution
Systems Plan
on-line survey
Data Tables
December 2017
UtilityPULSE

SIMUL/UtilityPULSE Collus PowerStream DSP Online Survey
FIELD DATES FROM JUNE 14 TO DECEMBER 1 2017

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BANNER1

Table 1 Page 1

SIMUL/UtilityPULSE Collus PowerStream DSP Online Survey
FIELD DATES FROM JUNE 14 TO DECEMBER 1 2017

Q1 - As a CPC customer, we are interested in your views on the 2018-2022 Distribution System Plan. Please indicate below whether you are a CPC residential or commercial customer:

	Total	Residential	Commercial
Total	10	9	1
Residential	9 90%	9 100%	-
Commercial	1 10%	-	1 100%

Table 2 Page 2

SIMUL/UtilityPULSE Collus PowerStream DSP Online Survey
FIELD DATES FROM JUNE 14 TO DECEMBER 1 2017

Q2 - The corporate objectives describe what CPC stands for and what it is trying to achieve.

	Total	Residential	Commercial
Total	10	9	1
Agree strongly	7 70%	6 67%	1 100%
Agree somewhat	2 20%	2 22%	-
Neither agree or disagree	1 10%	1 11%	-
TOP 2 BOX	9 90%	8 89%	1 100%
MEAN	4.60	4.56	5.00
SD	0.70	0.73	0.00
SE	0.22	0.24	0.00
MEDIAN	5.00	5.00	5.00

Table 3 Page 3

SIMUL/UtilityPULSE Collus PowerStream DSP Online Survey
FIELD DATES FROM JUNE 14 TO DECEMBER 1 2017

Q3 - A focus on corporate objectives will result in value to CPC customers.

	Total	Residential	Commercial
Total	10	9	1
Agree strongly	5 50%	5 56%	-
Agree somewhat	4 40%	3 33%	1 100%
Neither agree or disagree	1 10%	1 11%	-
TOP 2 BOX	9 90%	8 89%	1 100%
MEAN	4.40	4.44	4.00
SD	0.70	0.73	0.00
SE	0.22	0.24	0.00
MEDIAN	4.50	5.00	4.00

SIMUL/UtilityPULSE Collus PowerStream DSP Online Survey
FIELD DATES FROM JUNE 14 TO DECEMBER 1 2017

Q4 - Do you have any additional comments on the CPC corporate mission or objectives?

	Total	Residential	Commercial
Total	2	1	1
Other	2 100%	1 100%	1 100%

Nice to see you have a plan
I hear they are thinking about selling, I hope not

SIMUL/UtilityPULSE Collus PowerStream DSP Online Survey
FIELD DATES FROM JUNE 14 TO DECEMBER 1 2017

Q5 - The asset management objectives meet your expectations about how CPC intends to manage its assets.

	Total	Residential	Commercial
Total	10	9	1
Agree strongly	8 80%	7 78%	1 100%
Agree somewhat	2 20%	2 22%	-
TOP 2 BOX	10 100%	9 100%	1 100%
MEAN	4.80	4.78	5.00
SD	0.42	0.44	0.00
SE	0.13	0.15	0.00
MEDIAN	5.00	5.00	5.00

SIMUL/UtilityPULSE Collus PowerStream DSP Online Survey
FIELD DATES FROM JUNE 14 TO DECEMBER 1 2017

Q6 - The asset management objectives will result in distribution system performance that is of high value to you.

	Total	Residential	Commercial
Total	10	9	1
Agree strongly	8 80%	7 78%	1 100%
Agree somewhat	2 20%	2 22%	-
TOP 2 BOX	10 100%	9 100%	1 100%
MEAN	4.80	4.78	5.00
SD	0.42	0.44	0.00
SE	0.13	0.15	0.00
MEDIAN	5.00	5.00	5.00

SIMUL/UtilityPULSE Collus PowerStream DSP Online Survey
FIELD DATES FROM JUNE 14 TO DECEMBER 1 2017

Q7 - Do you have any additional comments on the CPC asset management objectives?

	Total	Residential	Commercial
Total	2	1	1
Other	2 100%	1 100%	1 100%

It has to be tough developing the plan
I think we need more stability at the hydro

SIMUL/UtilityPULSE Collus PowerStream DSP Online Survey
FIELD DATES FROM JUNE 14 TO DECEMBER 1 2017

Q8 - The Capital Investment plans meet your expectations for safe, reliable delivery of electricity for the near and long term

	Total	Residential	Commercial
Total	10	9	1
Very satisfied	6 60%	5 56%	1 100%
Somewhat satisfied	3 30%	3 33%	-
Somewhat unsatisfied	1 10%	1 11%	-
TOP 2 BOX	9 90%	8 89%	1 100%
BOTTOM 2 BOX	1 10%	1 11%	-
MEAN	4.40	4.33	5.00
SD	0.97	1.00	0.00
SE	0.31	0.33	0.00
MEDIAN	5.00	5.00	5.00

SIMUL/UtilityPULSE Collus PowerStream DSP Online Survey
FIELD DATES FROM JUNE 14 TO DECEMBER 1 2017

Q9 - The Maintenance Investment plans meet your expectations for getting the most out of equipment and technology for the near and long term

	Total	Residential	Commercial
Total	10	9	1
Very satisfied	5 50%	5 56%	-
Somewhat satisfied	5 50%	4 44%	1 100%
TOP 2 BOX	10 100%	9 100%	1 100%
MEAN	4.50	4.56	4.00
SD	0.53	0.53	0.00
SE	0.17	0.18	0.00
MEDIAN	4.50	5.00	4.00

SIMUL/UtilityPULSE Collus PowerStream DSP Online Survey
FIELD DATES FROM JUNE 14 TO DECEMBER 1 2017

Q10 - What changes, if any, would you like to see in the 2018-2022 Distribution System Plan spending programs?

	Total	Residential	Commercial
Total	3	2	1
Other	3 100%	2 100%	1 100%

I believe in active maintenance of equipment
I would like to know what a moderate increase means. What %
My rates keep going up, though I use very little hydro. It's very unfair.

SIMUL/UtilityPULSE Collus PowerStream DSP Online Survey
FIELD DATES FROM JUNE 14 TO DECEMBER 1 2017

Q11 - To what degree do you agree or disagree - CPC's expected investment outcomes will provide 'Value' to you, the customer.

	Total	Residential	Commercial
Total	9	8	1
Agree strongly	5 56%	5 62%	-
Agree somewhat	4 44%	3 38%	1 100%
TOP 2 BOX	9 100%	8 100%	1 100%
MEAN	4.56	4.62	4.00
SD	0.53	0.52	0.00
SE	0.18	0.18	0.00
MEDIAN	5.00	5.00	4.00

SIMUL/UtilityPULSE Collus PowerStream DSP Online Survey
FIELD DATES FROM JUNE 14 TO DECEMBER 1 2017

Q12 - CPC's approach to its Distribution System Plan Asset Management program is a prudent proposal to help CPC achieve its corporate mission: 'Our business provides people with the energy for success, and with the necessities of life'

	Total	Residential	Commercial
Total	9	8	1
Agree strongly	6 67%	5 62%	1 100%
Agree somewhat	3 33%	3 38%	-
TOP 2 BOX	9 100%	8 100%	1 100%
MEAN	4.67	4.62	5.00
SD	0.50	0.52	0.00
SE	0.17	0.18	0.00
MEDIAN	5.00	5.00	5.00

SIMUL/UtilityPULSE Collus PowerStream DSP Online Survey
FIELD DATES FROM JUNE 14 TO DECEMBER 1 2017

Q13 - General comments on the Distribution System Plan:

	Total	Residential	Commercial
Total	3	2	1
Other	3 100%	2 100%	1 100%

Wow, I didn't think there was so much planning being done.
After reading this survey, I realize how important it is to have people I trust at the hydro
My main concern is getting lower hydro rates.

SIMUL/UtilityPULSE Collus PowerStream DSP Online Survey
FIELD DATES FROM JUNE 14 TO DECEMBER 1 2017

Q14 - Would you like a Collus PowerStream representative to contact you?

	Total	Residential	Commercial
Total	10	9	1
Yes	1 10%	1 11%	-
No	9 90%	8 89%	1 100%

SIMUL/UtilityPULSE Collus PowerStream DSP Online Survey
FIELD DATES FROM JUNE 14 TO DECEMBER 1 2017

Q15 - Could you tell us the subject matter you would like addressed?

	Total	Residential	Commercial
Total	1	1	-
Other	1 100%	1 100%	-

SIMUL/UtilityPULSE Collus PowerStream DSP Online Survey
FIELD DATES FROM JUNE 14 TO DECEMBER 1 2017

Q17 - May we provide CPC with a copy of your survey responses?

	Total	Residential	Commercial
Total	1	1	-
No	1 100%	1 100%	-

Appendix G

2017 – 2023 Capital by G/L

CAPITAL EXPENSES

		Yearly Budget Totals						
	Year	2017	2018	2019	2020	2021	2022	2023
Account	**Substation**	**$51,087**	**$51,087**	**$300,000**	**$75,000**	**$76,875**	**$79,181**	**$81,161**
1820	Station Equipment	$0	$0	$0	$0	$0	$0	$0
1980	SCADA	$51,087	$51,087	$300,000	$75,000	$76,875	$79,181	$81,161
1808	Buildings	$0	$0	$0	$0	$0	$0	$0
1805	Land	$0	$0	$0	$0	$0	$0	$0
1830	**Poles, Towers and Fixtures**	**$589,100**	**$997,755**	**$839,013**	**$1,126,168**	**$1,091,328**	**$1,324,404**	**$1,317,113**
1835	**Overhead Conductor and Devices**	**$605,255**	**$1,025,117**	**$862,022**	**$1,157,051**	**$1,121,256**	**$1,360,723**	**$1,353,233**
1840	**Underground Conduit**	**$352,831**	**$33,827**	**$227,016**	**$38,180**	**$36,999**	**$44,901**	**$44,654**
1845	**Underground Conductor and Devices**	**$233,011**	**$22,551**	**$118,636**	**$25,454**	**$24,666**	**$29,934**	**$29,769**
1850	**Line Transformer**	**$67,210**	**$65,211**	**$209,455**	**$73,604**	**$71,327**	**$86,560**	**$86,083**
1855	**Services**	**$268,094**	**$26,009**	**$36,738**	**$29,357**	**$28,449**	**$34,524**	**$34,334**
1860	**Meters**	**$139,533**	**$139,533**	**$142,184**	**$144,886**	**$147,638**	**$150,444**	**$154,205**
1915	**Office Furniture and Equipment**	**$20,000**	**$20,000**	**$20,380**	**$20,767**	**$21,162**	**$21,564**	**$22,103**
1920/1925	**Computer Hardware & Software**	**$100,000**	**$100,000**	**$101,900**	**$103,836**	**$105,809**	**$107,819**	**$110,515**
1930	**Vehicles and Equipment**	**$475,000**	**$500,000**	**$240,000**	**$500,000**	**$425,000**	**$100,000**	**$400,000**
1940	**Tools, Shop, and Garage Equipment**	**$31,334**	**$31,930**	**$31,930**	**$33,154**	**$33,784**	**$34,426**	**$35,287**
	TOTAL	**$2,932,455**	**$3,013,020**	**$3,129,275**	**$3,327,456**	**$3,184,292**	**$3,374,480**	**$3,668,456**

CONTRIBUTED CAPITAL

		Yearly Budget Totals						
	Year	2017	2018	2019	2020	2021	2022	2023
	Customer Initiated	**$475,000**	**$484,025**	**$493,221**	**$701,935**	**$711,485**	**$731,183**	**$798,801**
1830	Poles, Towers and Fixtures	$0	$0	$0	$100,000	$100,000	$105,000	$110,000
1835	Overhead Conductor and Devices	$122,500	$124,828	$127,199	$129,616	$132,079	$134,588	$148,047
1850	Line Transformer	$140,000	$142,660	$145,371	$148,133	$150,947	$153,815	$169,197
1840	Underground Conduit	$17,500	$17,833	$18,171	$18,517	$18,868	$19,227	$21,150
1845	Underground Conductor and Devices	$70,000	$71,330	$72,685	$74,066	$75,474	$76,908	$84,598
1855	Services	$125,000	$127,375	$129,795	$231,604	$234,117	$241,645	$265,810
	Road Authority	**$138,375**	**$141,005**	**$143,684**	**$146,414**	**$149,195**	**$152,030**	**$167,233**
1830	Poles, Towers and Fixtures	$63,611	$64,819	$66,051	$67,306	$68,584	$69,888	$76,876
1835	Overhead Conductor and Devices	$65,355	$66,597	$67,862	$69,151	$70,465	$71,804	$78,985
1840	Underground Conduit	$2,157	$2,198	$2,239	$2,282	$2,325	$2,369	$2,606
1845	Underground Conductor and Devices	$1,438	$1,465	$1,493	$1,521	$1,550	$1,580	$1,738
1850	Line Transformer	$4,157	$4,236	$4,317	$4,399	$4,483	$4,568	$5,024
1855	Services	$1,658	$1,690	$1,722	$1,755	$1,788	$1,822	$2,004
	Subtotal	**$613,375**	**$625,030**	**$636,905**	**$848,349**	**$860,680**	**$883,213**	**$966,034**
2440	**Contributed Capital**	**($449,875)**	**($458,423)**	**($467,133)**	**($476,009)**	**($654,494)**	**($672,182)**	**($729,658)**
	Customer Initiated (85% Contributed until	($403,750)	($411,421)	($419,238)	($427,205)	($604,762)	($621,505)	($678,981)
	Road Authority (1/3 Contributed)	($46,125)	($47,002)	($47,895)	($48,805)	($49,732)	($50,677)	($50,677)
	TOTAL	**$163,500**	**$166,607**	**$169,772**	**$372,340**	**$206,186**	**$211,031**	**$236,377**

NET CAPITAL	**$3,095,955**	**$3,179,627**	**$3,299,047**	**$3,699,796**	**$3,390,479**	**$3,585,511**	**$3,904,833**